Australian Energy Market Commission

CONSULTATION PAPER

INVESTIGATION INTO INTERVENTION MECHANISMS AND SYSTEM STRENGTH IN THE NEM

4 APRIL 2019

INQUIRIES

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ABOUT THE AEMC

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

SUMMARY

1 A growing number of directions are being issued by AEMO to synchronous generators in South Australia to maintain adequate system strength. When AEMO intervenes in the market in this way, it is required to compensate both market participants who were directed, and also those that were affected by the direction. AEMO also implements 'intervention pricing', a practice designed to minimise market distortion by preserving the price signals the market would have sent but for the intervention in the market. The increased use of directions and intervention pricing in South Australia has important implications for wholesale electricity prices, both in South Australia and across the NEM. It affects wholesale electricity prices and market signals to investors, and the energy and compensation costs faced by consumers.

2 Directions are an important part of the intervention framework of the NEM. The intervention framework – the system's 'safety net' – includes not only directions, but the Reliability and Emergency Reserve Trader (RERT), and instructions. The intervention framework has always been available to AEMO as a last resort to keep the lights on.

3 In its final report of the *Reliability Frameworks Review* in July 2018, the Commission recommended that the appropriateness of the interventions framework, and the cost implications of the compensation framework associated with it, be reviewed in light of the increased use of interventions. The Commission considers it necessary to review the interventions framework in light of not only the recent use of the RERT but importantly because of the growing number of directions being issued by AEMO to maintain minimum levels of system strength in South Australia. The number of directions issued has risen significantly over the last two years, including since the Commission finished its *Reliability Frameworks Review*. While the intervention framework provides an important stop gap, it is not without costs and is not intended to be used to provide ongoing maintenance of power system security.

4 This paper actions the recommendation set out in the *Reliability Frameworks Review*. It also commences consultation on two rule change requests submitted by the Australian Energy Market Operator (AEMO) which seek to amend the interventions framework and related compensation framework. These rule change requests are being progressed as part of this wider investigation as they raise fundamental questions about the interventions framework.

5 Finally, the paper considers the current framework for managing system strength, and considers whether any refinements are warranted to that framework to support system security in the most efficient manner possible. In the case of South Australia, the frequent use of directions by AEMO would not be necessary if contracts with synchronous generators for the provision of system strength services, or other measures such as synchronous condensers, were in place as envisioned by the framework in the NER for managing system strength.

6 Interventions to maintain system strength

7 Low system strength has emerged as an issue in South Australia as the generation mix in that region shifts from one dominated by synchronous generators to one with a growing

proportion of asynchronous renewable generation. Currently, low system strength in South Australia is addressed through AEMO issuing directions to synchronous generators to operate in order to meet minimum system strength requirements. As at late March 2019, around 210 directions have been issued to South Australian generators to maintain system strength, representing an unprecedented use of this intervention mechanism. For the first time in November 2018, AEMO also issued a direction to a generator in Victoria to maintain adequate system strength there. This highlights that low system strength can be expected to pose challenges in other NEM regions in the near to mid-term.

8 Issues such as declining system strength are not unique to South Australia or the NEM more broadly. They are emerging in energy systems around the world as rapid changes in technology, consumer preferences and government policy drive significant energy market transition. Transformation on this scale means that regulatory and market settings must evolve as the generation mix changes so that energy systems can remain secure and reliable. This investigation is part of that ongoing process and builds on the work already undertaken by the Commission to develop new regulatory frameworks to manage system security, including system strength and inertia, amongst others.

9 The framework for managing system strength has been in place in South Australia since late 2017 (and other regions since 1 July 2018). AEMO first identified declining South Australian system strength as an issue in the December 2016 *National Transmission Network Development Plan*. In early December 2016, AEMO announced that at least two large synchronous generating units should be online at all times to maintain system strength in South Australia. This requirement has evolved over time and now comprises a complex suite of 51 combinations involving 16 generating units across seven power stations. Directions to maintain system strength were issued on seven occasions in 2017, prior to AEMO formally declaring a system strength shortfall in South Australia on 13 October 2017.

10 As a result, ElectraNet (the transmission network service provider or TNSP in South Australia) was obliged to use reasonable endeavours to procure system strength services to address the shortfall by 30 March 2018 (being the date specified in the notice issued by AEMO to ElectraNet). ElectraNet's analysis identified that installing synchronous condensers was the least costly means to provide the required services. However, this option was not possible to implement by 30 March 2018. As such, the only option that could be implemented in the time available was to contract with generators for the provision of system strength services.

11 Following a tendering process, ElectraNet concluded that generator contracting was a more costly option than continuing to rely on AEMO issuing directions. As a result, it did not proceed with the option of generator contracting, and is instead procuring synchronous condensers to address the shortfall in the medium term. The Commission notes that ElectraNet's initial options analysis was undertaken when only relatively few directions had been issued (directions had been issued on only ten occasions as at the end of 2017). Since then, the number of directions issued, and associated costs, have increased markedly. In addition, the expected date for commissioning the synchronous condensers has been moved back to the end of 2020, a timeframe longer than initially estimated.

12 Until such time as the synchronous condensers are commissioned, AEMO is directing

synchronous gas fired generators to ensure adequate system strength in South Australia. AEMO has the power to intervene in the market, as a last resort, to maintain a secure system. This is necessary when there are insufficient synchronous generators online, noting that system strength is not an inherent characteristic of asynchronous generators. Usually, directions are required when spot prices fall to levels that are not sufficient to cover gas fired generators' short run costs (typically during periods of high wind output and low to moderate demand). During 2018, such directions were in place for 30 per cent of the time on average – a very significant increase relative to the past, and one that is at odds with the principle in the NER that intervention mechanisms should only be used as a last resort.

13 Issues to be considered through this investigation

14 When AEMO issues system strength directions in South Australia, it implements 'intervention pricing', a practice designed to minimise market distortion by preserving scarcity price signals (that is, the price signals from the market that provide incentives to generators and investors to act in a certain way). The application of intervention pricing in South Australia has important implications for wholesale prices, both in South Australia and across the NEM. This affects market signals to investors and the energy costs faced by consumers. In addition, market customers bear the cost of compensating both directed participants (those who provide services under direction) and affected participants (those whose dispatch targets are affected as a consequence of the direction).

15 There is very limited transparency about the extent of these cost impacts. While some high level data on compensation costs is published, no information is readily available about the impact of intervention pricing on wholesale energy prices. A recent ElectraNet report puts the cost of compensation for system strength directions in South Australia at $34 million per annum. In addition, the report refers to the wider impact of intervention pricing on wholesale market outcomes as exceeding $270m as at September 2018.

16 AEMC analysis similarly indicates that intervention pricing has had a marked impact on wholesale prices in South Australia, as well as impacting prices across the NEM. In South Australia, spot prices in 2018 were on average 10 per cent higher than they would have been had intervention pricing not been applied in connection with system strength directions. The Commission recognises that this is an upper limit of the estimated impact of intervention pricing in South Australia. This is because the market could be expected to "self-correct" to some degree if intervention pricing did not apply and spot prices were allowed to fall when system strength directions are issued. In addition, higher spot prices due to intervention pricing do not translate directly and immediately into higher energy bills, as most retailers have hedge contracts in place. However, an impact of this magnitude can be expected to inform expectations as to future spot prices, and so contract prices. In this way, higher spot prices due to system strength directions and intervention pricing put upward pressure on energy bills.

17 Intervention pricing has also impacted other regions of the NEM, although to a lesser degree than in South Australia. Nonetheless, these impacts warrant consideration given the potential for issues of low system strength to increase over time and the higher volume of energy traded in those regions.

18 AEMO has submitted a rule change request relating to the "regional reference node test" (RRN test), a test set out in the National Electricity Rules (NER) which is used by AEMO to determine when intervention pricing should apply. This rule change request is being progressed through this investigation. In the case of the system strength directions in South Australia, the RRN test is met (and therefore intervention pricing applies) because the South Australian generators which are directed to provide system strength services happen to be located at or very near to the RRN. However, this is not the case in most other regions, meaning that the test may not deliver predictable and consistent outcomes across the NEM.

19 AEMO's rule change request proposes changes to the wording of the RRN test, and seeks to extend its application to encompass the Reliability and Emergency Reserve Trader (RERT), in addition to directions. The proposal to amend the wording of the test has prompted the Commission to consider how the test should be drafted in order to achieve the objective of preserving market price signals and minimising market distortion. The paper considers the circumstances in which intervention pricing should apply and, in particular, whether it should continue to apply in connection with system strength directions (and directions for other services for which there are no relevant market price signals to preserve).

20 Another important issue examined in the paper is the hierarchy of intervention mechanisms set out in the NER, in particular the requirement that, where the RERT has been procured, it should be used in preference to directions and instructions. Given the cost of the RERT relative to other mechanisms, this provision may produce inefficient cost impacts on consumers. The paper explores whether a different approach should be adopted to minimise costs to consumers.

21 The paper also discusses the compensation framework that is triggered when AEMO intervenes in the market. It explores issues such as whether compensation should be payable to affected participants, and whether the quantum of compensation payable to directed participants is having unintended effects on the bidding behaviour of South Australian generators. AEMO has submitted a rule change request which seeks to amend the $5,000 threshold per trading interval which limits the amount of compensation payable to directed and affected participants. This rule change request will be progressed through this investigation.

22 Finally, the paper explores the current application of the minimum system strength and inertia frameworks. The Commission considers it useful to revisit how the minimum system strength and inertia frameworks have been applied to date in light of the potentially substantial impacts on costs facing consumers arising from the use of directions and the application of the intervention pricing and compensation frameworks. These impacts highlight the importance of ensuring that shortfalls are identified early enough that least cost measures can be implemented in time, thereby obviating the need to rely on more costly options, or AEMO directions, to maintain adequate system strength.

23 In addition to the directions being issued in South Australia, system strength related issues are emerging in other regions of the NEM. As such, the paper also considers whether the timeframes and level of flexibility in these frameworks are sufficient to deliver optimal outcomes when addressing emerging system strength and inertia shortfalls as they arise in

NEM regions other than South Australia. A more flexible framework may limit the need to rely on directions and so avoid the high costs that this can entail.

24 The Commission is particularly interested in how well the frameworks accommodate emerging system strength and inertia related issues where there may be a risk of a shortfall occurring but only for a certain time of the year or only under certain circumstances, or where conditions in the power system suddenly change such that a shortfall in system strength is declared which needs to be addressed. Aspects of the framework that are explored in more detail include:

- The approach used to determine when and to what extent a fault level shortfall may be expected to arise. In particular, how AEMO should determine what "typical" dispatch patterns look like over a five-year period in a sector that is undergoing rapid transition.
- The timeframes in the system strength framework for addressing system strength issues. The framework provides TNSPs with at least 12 months to develop and implement the least-cost solution for meeting a shortfall.
- The flexibility afforded to AEMO in declaring the nature and extent of a system strength shortfall, and the level of flexibility provided to the TNSP in how it meets the shortfall.

25 These are important issues that have significant implications for market participants and consumers alike. The Commission invites stakeholders to provide feedback on the issues raised in this paper, and the rule change requests submitted by AEMO. This will inform the development of draft determinations for the two rule change requests as well as further analysis of what, if any, refinements are required to the regulatory frameworks governing interventions, system strength and inertia.

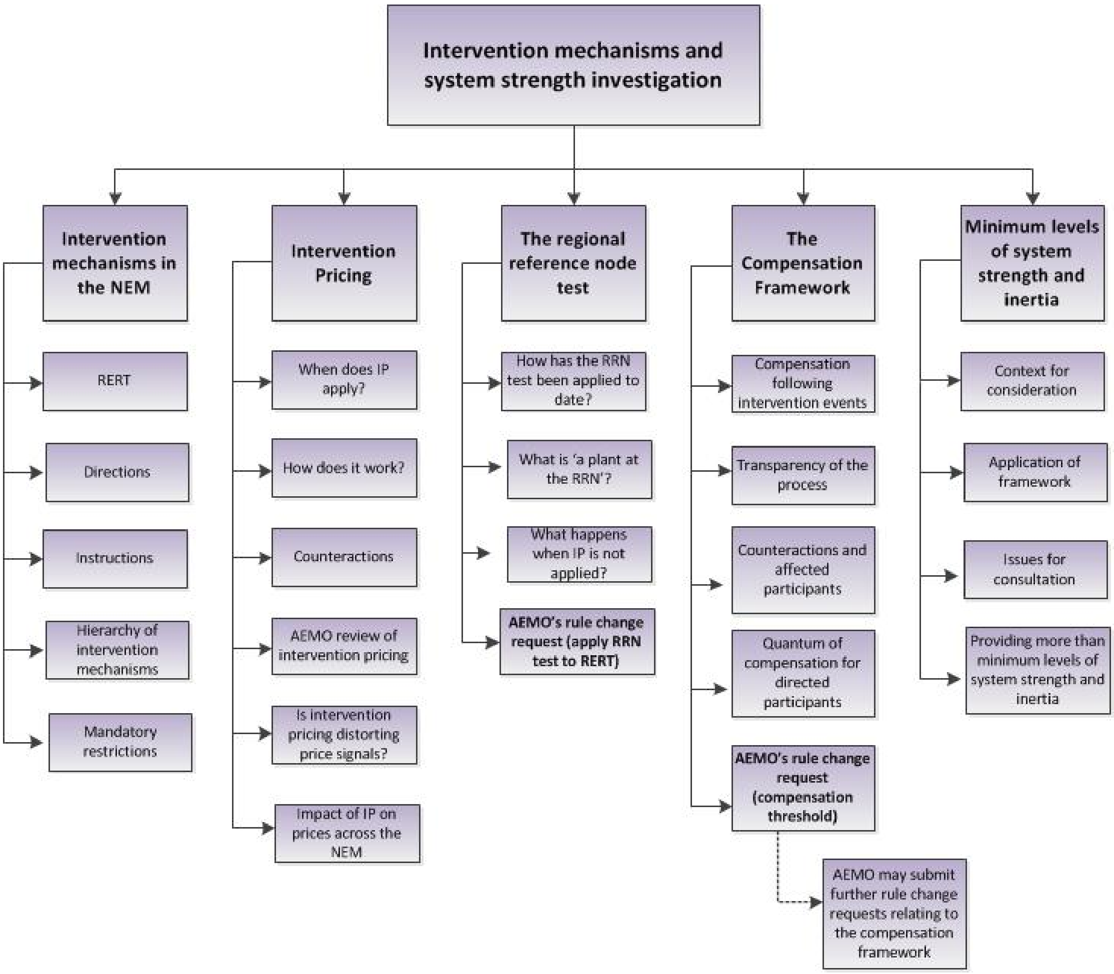
26 Other system strength issues not being considered as part of this investigation

27 The minimum system strength rule also places an obligation on new connecting generators to "do no harm" to the level of system strength necessary to maintain the security of the power system. The "do no harm" aspects of the system strength rule are not the focus of this investigation but discussion has been included for context. The Commission notes that this aspect of the framework may be resulting in some issues relating to the connection of new generators. This will be considered in the Commission's future work program.

28 The Commission also notes that, beyond the minimum levels of system strength and inertia, additional system strength and inertia have the potential to provide economic benefits by alleviating constraints in the power system and thereby increasing competition in the wholesale market. The Commission considers that these economic benefits are likely to increase as asynchronous generation grows and synchronous generators retire.

29 As part of its future work program, the Commission proposes to explore options to value additional system strength and inertia and to design and potentially implement a mechanism to pay for these services. The development of this mechanism will need to be undertaken in view of the range of other system services which may be necessary in the future to maintain a secure power system, and for which there are currently no incentives in place. There are many inter-relationships between these services, and they will need to be considered in a coordinated fashion in order to arrive at an efficient outcome in the interests of consumers.

Figure 1: Structure of the paper



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1 INTRODUCTION

The increasing use of interventions in South Australia and Victoria has drawn attention to a number of issues regarding the interventions framework set out in the National Electricity Rules (NER). The interventions framework comprises the Reliability and Emergency Reserve Trader (RERT), 'directions' and 'instructions'. The RERT was activated in Victoria in November 2017, and in South Australia and Victoria in January 2018 and January 2019 to address supply shortages. Directions are frequently being issued in South Australia to ensure adequate system strength and, in late 2018, a direction was also issued to a generator in Victoria to ensure adequate system strength in that region.

Instructions are another form of market intervention available to AEMO. These are typically used to instruct a transmission network service provider to shed load, for example in response to a lack of reserve condition. Finally, this paper also examines the mandatory restrictions dispatch and pricing framework, a framework that has not been used since its inclusion in the NER. Mandatory restrictions involve the imposition by a NEM jurisdiction of restrictions on electricity consumption, and a mechanism by which AEMO manages generator dispatch and pricing.

In response to concerns about increasingly frequent reliance on interventions, and in accordance with a recommendation made in the *Reliability Frameworks Review* final report[1], the Australian Energy Market Commission (AEMC or Commission) has commenced an investigation into the regulatory frameworks that govern the use of interventions in the National Electricity Market (NEM).

The AEMC has also received four rule change requests from AEMO relating to a number of issues with the design of the current interventions frameworks. Two of these rule change requests raise important issues and as such they will be progressed as part of this investigation. Issues raised by them are discussed in Chapters 5 and 6 of this paper.

On 4 April 2019, the Commission published a notice under section 95 of the National Electricity Law (NEL) setting out its decision to initiate the rule change process in relation to the other two rule change requests. These will be dealt with independently of this investigation as they involve issues that are machinery in nature and uncontroversial. Given this, these two rule change requests will be consolidated and progressed using an expedited process.

AEMO has indicated it intends to lodge further rule change requests relating to the interventions framework. These will be initiated separately and informed by this investigation into the NEM intervention mechanisms.

1.1 Outline of this paper

This consultation paper has been prepared to facilitate public consultation on the Commission's investigation into the design and application of the interventions framework in

1 AEMC, *Reliability Frameworks Review - Final Report*, July 2018

the NER and two of the four rule change requests received to date from AEMO that relate to the interventions framework.

This paper:

- Considers the efficiency and appropriateness of the interventions and compensation frameworks, including the hierarchy of interventions and the use of intervention pricing
- Describes issues related to the use of the interventions framework in managing power system security
- Sets out a summary of, and a background to, two of the four rule change requests submitted by AEMO
- Identifies a number of questions and issues to assist the AEMC in its approach to the investigation and to facilitate consultation on the rule change requests
- Examines issues associated with the minimum system strength and inertia frameworks
- Outlines the process for making submissions

Stakeholders are encouraged to comment on these or any other aspects of the paper.

1.2 Purpose of this investigation

The purpose of this investigation is to explore potential changes to regulatory frameworks which may be required in order to meet the challenges created by the changes in technology which impact system security and AEMO's increasing use of interventions to manage system security.

Issues relating to the intervention framework were identified in the AEMC's Reliability Frameworks Review Final Report as warranting further investigation. That report acknowledged that intervention mechanisms are an important feature of the market design, allowing AEMO to intervene in the market (as a last resort) when such action is required to maintain reliability or security. However, the report also identified that the increasing use of directions and intervention pricing is impacting the energy and compensation costs borne by consumers, and may be distorting price signals to investors. It recommended that the Commission:

- consider the intervention mechanisms from the perspective of how interventions occur and operate as a suite of mechanisms,
- 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, and
- progress any rule change requests submitted by AEMO on the intervention pricing and compensation framework in conjunction with this investigation.

This paper progresses the recommendations made in that report as well as examining a number of other issues relating to the interventions framework more broadly. It builds on the work of the Intervention Pricing Working Group (IPWG) which was established by AEMO when unexpected outcomes from the implementation of intervention pricing prompted AEMO to conduct a review of intervention pricing. As part of that review, AEMO commissioned a report by SW Advisory and Endgame Economics.[2] It also established the IPWG to consider the recommendations in that report as well as a number of other issues which are now being progressed by the AEMO rule change requests.[3] The AEMC's investigation will draw upon the work undertaken to date by AEMO and the IPWG.

1.3 Scope of this investigation

The AEMC's investigation will explore issues associated with the current interventions and compensation frameworks in the NER and will identify potential changes that could improve the efficiency and effectiveness of the frameworks. The investigation will consider the application of the interventions framework to the maintenance of system security as well as reliability, and the hierarchy, or sequence of use, of the three different intervention mechanisms (RERT, directions and instructions).

Consideration will also be given to whether improvements can be made to the minimum system strength and inertia frameworks to more effectively and efficiently identify and address shortfalls in system strength and inertia as they arise in NEM regions. The framework for managing system strength has been in place in South Australia since 2017 (and other regions since 1 July 2018). In accordance with that framework, AEMO declared a system strength shortfall in South Australia in October 2017. As a result, ElectraNet (the transmission network service provider in South Australia) is obliged to procure system strength services to address the shortfall. It is currently procuring synchronous condensers which are expected to be commissioned by the end of 2020. AEMO has also declared an inertia shortfall in South Australia[4] and has recommended that ElectraNet fit flywheels to the synchronous condensers to provide additional inertia.

Until the synchronous condensers are commissioned, AEMO is directing synchronous gas fired generators to ensure adequate system strength in South Australia. During 2018, such directions were in place for 30 per cent of the time on average – a very significant increase relative to the past, and one that is at odds with the principle that intervention mechanisms should only be used as a last resort.

In light of this issue, the Commission is taking the opportunity to seek stakeholder feedback on the minimum system strength and inertia frameworks with the intention of making them as effective and efficient as possible. The application of these frameworks should obviate the need for AEMO to maintain system security by intervening in the operation of the market. However, the Commission intends to explore whether adjustments could be made to these frameworks to improve the flexibility with which they can be applied to address issues as they begin to emerge in other NEM regions. A more flexible framework may limit the need for the use of directions and interventions pricing, which can have unintended impacts on the wholesale price and investment signals.

2 SW Advisory and Endgame Economics, *Review of Intervention Pricing - Final Report prepared for AEMO*, 4 October 2017.

3 Terms of reference for the IPWG, the SW Advisory report and meeting minutes are available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group. The SW Advisory Report is available in the meeting pack for meeting 1

4 AEMO, *National Transmission Network Development Plan*, 2018

The minimum system strength and inertia frameworks are discussed further in Chapter 7 of this paper.

For any proposed changes to the interventions, system strength and inertia frameworks, the AEMC will:

- Identify the reasons for the proposed change and likely impacts on the NEM and consumers
- Describe pathways to implementation, including timing, possible interim stages and any necessary changes to the National Electricity Rules.

Any recommendations arising from this investigation will be reported to the COAG Energy Council, including any rule changes made in response to the rule change requests received. Recommendations may include possible changes to policy frameworks and potential future rule change requests, as well as any further actions where required.

1.4 The rule change requests

As noted earlier, unexpected outcomes from the implementation of intervention pricing prompted AEMO to conduct a review of intervention pricing. As a result of that work, AEMO has to date submitted four rule change requests relating to the interventions framework. (AEMO has indicated it intends to submit further rule change requests relating to the interventions framework in due course.) Two of the requests submitted to date are explored in this paper (Chapters 5 and 6), which will be used as the means to commence consultation on the rule change requests. The issues raised by these two rule change requests are:

- whether the 'regional reference node test' which currently applies only to directions (and determines whether intervention pricing should be implemented in connection with a direction) should also apply to the Reliability and Emergency Reserve Trader (RERT), and whether changes should be made to the test to clarify its operation[5]
- whether the current threshold of $5,000 (below which compensation is not payable to affected participants, and below which directed participants are not able to claim additional compensation) should apply per intervention event rather than per trading interval[6]

Two other rule change requests submitted by AEMO concern administrative issues which do not raise larger questions about the interventions framework. Issues addressed include whether the timeframes for interventions and settlements should be aligned in order to streamline cost recovery processes[7], and whether the deadline for submitting compensation claims should be extended from 7 to 15 business days.[8] These rule change requests will be progressed independently of this investigation of the interventions framework.

5 AEMO's rule change requests is available at https://www.aemc.gov.au/rule-changes/application-regional-reference-node-test-reliability-and-emergency-reserve-trader

6 AEMO's rule change request is available at https://www.aemc.gov.au/rule-changes/threshold-participant-compensation-following- market-intervention

7 AEMO's rule change request is available at https://www.aemc.gov.au/rule-changes/alignment-intervention-compensation-and-settlement-timetables

8 AEMO's rule change request is available at https://www.aemc.gov.au/rule-changes/deadlines-additional-compensation-claims-following-market-intervention

1.5 Structure of this report

The remainder of this consultation paper is structured as follows:

- Chapter 2 describes the current issues in relation to the use of the interventions framework in addressing issues of system security, including a description of the two rule change requests being progressed through this paper, the assessment approach, and guiding principles for the investigation and rule change requests
- Chapter 3 provides an explanation of the existing interventions mechanisms in the NEM
- Chapter 4 explores the application of the intervention pricing framework, including the role of intervention pricing in connection with the RERT and directions, when intervention pricing applies and how it works, and whether intervention pricing is distorting price signals when used in connection with system strength directions.
- Chapter 5 discusses the regional reference node (RRN) test which is used by AEMO to determine whether to apply intervention pricing when it issues a direction, including the origins of the test, how it has been applied to date, and the AEMO rule change request seeking to change the test and extend its application to encompass the RERT.
- Chapter 6 outlines the compensation framework that is triggered when AEMO intervenes in the market, including the payment of compensation to affected participants, the quantum of compensation payable to directed participants, and discusses the AEMO rule change request seeking to amend the $5,000 threshold per trading interval that limits the payment of compensation.
- Chapter 7 explores the current application of the minimum system strength and inertia frameworks and raises a number of aspects of the framework for further consideration, including whether the timeframes and level of flexibility in these frameworks are sufficient to lead to optimal outcomes when addressing emerging system strength and inertia shortfalls as they arise in NEM regions.
- Chapter 8 sets out the process for lodging a submission.

2 SUMMARY OF ISSUES AND ASSESSMENT APPROACH

This chapter sets out the nature of the recent interventions, explains the recent changes in the power system that have given rise to these interventions, and sets out the issues to be addressed.

This chapter also provides a description of AEMO's rule change requests and sets out the Commission's proposed assessment approach.

2.1 Concepts and background to the Commission's investigation and rule change requests

System strength refers to the relative change in voltage for a change in load or generation at a connection point. Low levels of system strength can jeopardise the ability of generators to operate correctly, thus impacting system security. System strength is usually measured by the available fault current at a given location or by the short circuit ratio.[9] Fault current differs from:

- frequency (which relates to the rotational speed of the synchronous generators connected to the system),
- inertia (which refers to the inherent capacity of large spinning machines to dampen the rate of change of frequency following a contingency event that produces an imbalance in active power supply and demand), and
- voltage (which is regulated by the injection or absorption of reactive power to manage the voltage at a given point in the power system).

Low system strength has emerged as an issue in South Australia in 2017-2018 as the generation mix in that region has shifted from one dominated by synchronous generators to one with a growing proportion of asynchronous renewable generation. Such issues are not unique to South Australia. They are emerging in energy systems around the world as rapid changes in technology, consumer preferences and government policy drive significant energy market transition. These changes mean that regulatory and market settings need to evolve to ensure that energy systems remain secure and reliable. This investigation is part of that ongoing process.

ElectraNet intends to address the shortfall in system strength in South Australia through the construction of synchronous condensers, in accordance with its obligation under the *Managing power system fault levels* rule made by the Commission in September 2017.

In the meantime, AEMO has been intervening in the operation of the market through the issuance of directions to synchronous generators to maintain minimum levels of system strength. AEMO first directed generators to provide system strength in South Australia in April

9 System strength service is defined in chapter 10 of the NER as 'a service for the provision of a contribution to the three phase fault level' at a given location in the transmission network.

2017. The second occasion was in September 2017 and, since then, directions have become increasingly frequent.

The increasing use of directions in South Australia has drawn attention to a number of issues regarding the interventions framework, including the impact of directions and intervention pricing on spot prices and investment signals, and the impact on consumers of both intervention pricing and compensation payments to directed and affected participants.

2.1.1 Why is system strength low in South Australia?

The generation mix in South Australia is changing rapidly. The market share of large scale asynchronous generators (predominantly wind) has grown rapidly, while operational demand is falling due to the increased penetration of residential scale photovoltaic systems. Some synchronous generators (e.g. Northern Power) have already retired and other synchronous generating units are expected to withdraw from the market in the near term.[10]

When demand is low to moderate and output from wind generation is high, spot prices in South Australia fall to low levels, making it difficult for gas fired generators to earn sufficient revenue to recover their short run costs. As a result, synchronous generators may bid unavailable, thus reducing the number of synchronous generating units operating during such periods. This has resulted in low levels of fault current, a service that has historically been provided by synchronous generators and is not typically provided by asynchronous generators. This has resulted in reduced system strength, as discussed further in Chapter 7.

2.1.2 What is the current approach to managing low system strength?

AEMO's Integrated System Plan (ISP) identified system strength as both an existing and emerging challenge in the NEM.[11] System strength will remain relatively high in many parts of the NEM while synchronous generators operate there (including those parts of the NEM with strong transmission links to large synchronous generators). However, there is low system strength at the fringes of the grid, particularly in north Queensland, south-west New South Wales, north-western Victoria, and South Australia.

In South Australia, where the shift in the generation mix has been more pronounced, system strength is falling and is no longer adequate when insufficient gas fired units are operating. When such generators do not have a commercial incentive to operate due to low spot prices, AEMO directs one or more synchronous gas fired generators to remain online to maintain adequate system strength.

In Victoria, recent events have shown that system strength may also be inadequate in that region when multiple synchronous generating units are offline at the same time (see Chapter 7 for more detail).

10 For example, Torrens Island A power station will be progressively mothballed between 2019 and 2021: AEMO generator information page available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

11 AEMO, *Integrated system plan*, 2018, pp. 72-73.

In 2016, the South Australian Government requested the AEMC to make a rule regarding power system fault levels (low fault current levels indicate inadequate system strength). In response, the AEMC made a final rule which places an obligation on TNSPs to procure minimum levels of system strength where AEMO has determined that system strength is inadequate and declared a shortfall.[12] The application of these frameworks should obviate the need for AEMO to maintain system security by intervening in the operation of the market.

As discussed in the following section, the Commission intends to explore whether adjustments could be made to this framework to improve the flexibility with which it can be applied to address issues as they begin to emerge in other NEM regions.

The minimum system strength rule was published together with a related rule which imposes similar requirements on TNSPs to maintain minimum levels of inertia.[13] Under the rules, AEMO has declared shortfalls in system strength and inertia in South Australia. ElectraNet has committed to meeting the shortfalls through the construction of synchronous condensers which it found to be the most efficient solution in the short to medium term.

ElectraNet sought offers from market participants in South Australia to meet the minimum system strength requirements but ultimately determined that generator contracting was not an economically viable solution and proposed that, prior to the commissioning of the synchronous condensers, AEMO continue with directing synchronous gas fired generators in the short term. In reaching this conclusion, ElectraNet had regard only for the direct cost of directions-related compensation, an issue discussed further in Chapter 7.

2.1.3 What are the issues with managing system strength through the use of interventions

The increasing use of directions in South Australia has drawn attention to a number of issues regarding the interventions framework, including the impact of directions and intervention pricing on spot prices and investment signals, and the impact on consumers of both intervention pricing and compensation payments to directed and affected participants.

Intervention pricing is designed to reduce market distortion by preserving the scarcity price signals that would be conveyed but for the intervention.[14] For example, if AEMO issues a direction to a generator to provide additional capacity in response to a low reserve condition, the spot price would normally be expected to fall when the additional generation comes on line (relative to the spot price associated with the previously tight supply demand balance).[15] This would have the effect of muting the price signal that is intended to convey the need for investment in additional capacity to meet demand. In such cases, intervention pricing is implemented in order to preserve prices at the level that would have occurred had the direction not been issued. Thus, the 'intervention price' is higher than the spot price would be if intervention pricing was not used.

12 AEMC, *Managing power system fault levels, Rule Determination*, September 2017.

13 AEMC, *Managing the rate of change of power system frequency, Rule Determination*, September 2017.

14 An 'AEMO intervention event' is defined in chapter 10 of the NER as including directions and the RERT, but not clause 4.8.9. instructions or mandatory restrictions.

15 Note that the dispatch offer of the generator directed to provide services is not taken into account in setting the dispatch price: clause 3.9.1(3A) of the NER.

However, where the service being provided in response to a direction is not a commodity traded in the market (e.g. system strength), the use of intervention pricing can have unintended distortionary effects - keeping prices higher than they would otherwise be and conveying a distorted signal regarding the need for additional investment in energy capacity, regardless of whether that capacity supports or degrades system strength. Using intervention pricing for a high proportion of the time amplifies this effect, an issue which is discussed further in Chapter 4.

AEMO's Quarterly Dynamics Report for the period July to September 2018 notes that:[16]

> AEMO intervened on multiple occasions to direct synchronous generation to remain online to ensure adequate system strength in South Australia and thereby maintain the grid in a secure operating state. On average, directions were in place [in South Australia] for around 40% of the time during the quarter, with a [compensation] cost of $7.4 million, which was $0.35 million higher than the prior quarter.
>
> This compares with directions in place for 50% of the time in Q2 2018 and 30% in the period since the system strength unit combinations were introduced in September 2017. Key drivers of system strength directions during the quarter included periods of relatively low prices (<$50/MWh) and high wind output (>1,100 MW) which resulted in synchronous generators seeking to decommit from the market for commercial reasons.

In addition to the compensation costs noted above, the use of intervention pricing in connection with directions has implications for wholesale energy prices and investment signals, and may place upward pressure on energy costs passed through to consumers. This is an existing concern in South Australia where market customers, and ultimately consumers, bear the cost of compensation payments resulting from directions issued to maintain system security in South Australia.

While the impact of intervention pricing on wholesale energy prices is most marked in South Australia, its impact is not limited to South Australia. As discussed in Chapter 4, intervention pricing is putting upward pressure on energy prices in South Australia and, to a lesser extent, across the NEM. Such cost impacts (due both to compensation payments and wholesale energy price impacts) may become more marked in regions other than South Australia in the near to mid-term, particularly as the generation mix changes in areas such as north-west Victoria, south-west NSW and northern Queensland.

For the first time on 17 November 2018, AEMO directed a generator in Victoria to remain online in order to ensure adequate system strength. While AEMO had anticipated that system strength would emerge as an issue in Victoria in the mid-term,[17] extenuating circumstances (including multiple synchronous generating units being unavailable at the same time) brought system strength to the fore earlier than expected. AEMO has indicated it is undertaking detailed power system modelling to determine the combinations of synchronous generators

16 AEMO, *Quarterly Energy Dynamics Q3 2018*, November 2018, p. 7.

17 AEMO, *Integrated System Plan*, July 2018, p.73.

that need to be online to ensure adequate system strength in Victoria (replicating the approach adopted in South Australia).

The implementation of intervention pricing in connection with the Victorian directions further highlights the need to address issues relating to the intervention pricing framework, including the application of the regional reference node (RRN) test.[18] The RRN test is used to determine, once a direction has been issued, whether intervention pricing should be implemented in connection with that direction.[19]

As noted above, the use of intervention pricing may have distortionary effects if used in connection with a direction for a service (such as system strength) that is not traded in the market. Accordingly, this paper will explore whether the current test is working as intended and whether there would be benefit in amending it.

2.1.4 Is there sufficient flexibility in the existing frameworks for minimum system strength and inertia?

In the *Managing power system fault levels* final rule, the Commission introduced an obligation, if a shortfall is declared by AEMO, for transmission network service providers (TNSPs) to provide for the minimum level of system strength necessary to maintain the power system in a secure operating state (referred to as the 'minimum level of system strength'). This framework came into effect on 1 July 2018. The final rule also set out transitional arrangements that allowed the framework to apply in South Australia prior to 1 July 2018. In September 2017, AEMO declared an NSCAS gap related to system strength and, in accordance with the transitional arrangements, ElectraNet elected to treat this as a fault level shortfall under the minimum system strength framework.

Also on 1 July 2018, a similar framework was introduced for the minimum level of inertia in the final rule for *Managing the rate of change of power system frequency*.[20] AEMO declared a shortfall in inertia in South Australia in December 2018.[21]

Experience with implementing the framework in South Australia, together with the likelihood that shortfalls may be declared in other regions in the near to mid-term, raises a number of issues as to whether the framework is delivering optimal results. This paper provides an opportunity to seek stakeholder feedback on the operation to date of the minimum system strength and inertia frameworks. The Commission intends to consider whether the timeframes and level of flexibility in these frameworks are appropriate to lead to optimal

18 RRNs are typically located near the major load centres in each region of the NEM - i.e. in capital cities. The central dispatch process sets prices at the RRN: clause 3.9.1(a)(1) of the NER. The essence of the RRN test is whether directing a plant at the RRN would have avoided the need for the direction which constituted the intervention. For example, if a plant needs to be directed on in northern Queensland due to a cyclone damaging the transmission network in central Queensland, directing a plant at the RRN in Brisbane would not solve the problem. In such cases, no intervention pricing is warranted since there is no region-wide scarcity which should be reflected in the spot price. By contrast, if there is a general lack of energy or frequency control ancillary services (FCAS) and additional capacity coming on line anywhere in the region would address the deficiency, then the test is met and intervention pricing should apply (to preserve the scarcity price signal that would be conveyed to the market if the intervention did not occur).

19 See clause 3.9.3(d) of the NER.

20 National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017 No. 9

21 AEMO, *National Transmission Network Development Plan*, December 2018, pp. 4-5.

outcomes when addressing emerging system strength and inertia shortfalls as they arise in NEM regions. Issues discussed include:

- how shortfalls are identified and when they are declared[22]
- the timeframes for addressing system strength and inertia issues once a shortfall has been declared
- whether TNSPs should have more flexibility in how they meet a system strength or inertia shortall
- whether there would be value in incentivising the provision of system strength and inertia services beyond minimum required levels

2.1.5 Is the current hierarchy of interventions appropriate?

The increasing use of interventions in South Australia and Victoria has heightened the interest in the use of intervention mechanisms in the NEM. The NER include a principle that AEMO decision-making should be minimised to allow market participants the greatest amount of commercial freedom to decide how they will operate in the market.[23] Consistent with this, AEMO considers the use of interventions to be a last resort.

When interventions are used during times of 'supply scarcity', AEMO must use reasonable endeavours to first exercise the RERT (if it has been procured) and then, if necessary, issue either directions or instructions[24]. The NER do not specify a priority as between directions (which require registered participants to take action in relation to scheduled plant and market generating units) and instructions (which require registered participants to take actions other than in relation to scheduled plant and market generating units). In practice, AEMO uses directions where practicable and instructions to shed load only very rarely.[25]

The Commission intends to consider whether this hierarchy of intervention (RERT first, then directions and/or instructions) delivers the best outcomes for consumers.

2.2 The rule change requests

This section provides a summary of the AEMO rule change requests received by the AEMC that relate to the application of the RRN test to the RERT and the $5,000 threshold for compensation. A separate consultation paper has been published to facilitate consultation on the two rule change requests received from AEMO on the alignment of timeframes for interventions and settlement and the extension of the deadline for submitting compensation

22 The Commission recognises the tension between, on the one hand, the need to identify a potential shortfall over a five year planning horizon (e.g. based on high level trends such as falling demand and increasing asynchronous generating capacity) and, on the other hand, the need for specificity in declaring the shortfall and quantifying the services that the TNSP must procure in response. Consideration is given to whether, for example, there may be value in requiring AEMO to issue both preliminary and final shortfall notices to help resolve this tension.

23 See clause 3.1.4(a)(1) of the NER.

24 See clause 3.8.14 of the NER.

25 AEMO states that it views load shedding as an 'absolute last resort' – AEMO, *Summer 2017-2018 Operations Review*, May 2018, p. 17.

claims from 7 to 15 business days.[26] AEMO has also signalled its intention to submit further rule change requests in relation to the intervention framework.

Table 2.1: **Summary of AEMO rule change requests received to date**

RULE CHANGE REQUEST	HOW PROGRESSED	TIMEFRAMES
Extending the application of the RRN test to the RERT	As part of this investigation – see Chapter 5	Normal process, with six week consultation period
Changing the $5,000 compensation threshold to apply per intervention event	As part of this investigation – see Chapter 6	As above
Aligning intervention and settlement timeframes	Consolidated with rule change below	Expedited
Extending the claims deadline from 7 to 15 business days	Consolidated with rule change above	Expedited

2.2.1 Application of the RRN test to the RERT

AEMO's rule change request proposes to extend the reach of the RRN test (to encompass the RERT in addition to directions) and to clarify the wording of the test to remove ambiguity.[27] It notes that the rule change request has been developed in discussion with the Intervention Pricing Working Group (discussed in Chapter 5), members of which supported extending the application of the RRN test to encompass the RERT.[28] It is noted, however, that the proposed amendments to the wording of the RRN test were not presented to or discussed with the IPWG. AEMO notes that the proposal to extend the RRN test to encompass the RERT was also presented to the NEM Wholesale Consultative Forum.

In relation to the RERT, AEMO notes that, currently, intervention pricing is applied whenever the RERT is activated, regardless of whether there is value in a scarcity price signal at the RRN. Reducing the application of intervention pricing in connection with the RERT "would prevent the application of higher intervention prices for all intervention events where there is no value in a scarcity price signal at the RRN. This has the potential to reduce costs for consumers".[29] AEMO considers that, in this way, the proposed rule change would "mitigate additional market costs that would arise from exercising the RERT under conditions that do not satisfy the RRN test". Such outcomes are said to directly promote the National Electricity Objective (NEO) by "maintaining the efficient operation of electricity services for the long term interests of consumers with respect to price and security of supply".[30]

26 AEMC, *Consultation Paper - National Electricity Amendment (Intervention compensation and settlement processes) Rule 2019*, April 2019

27 The rule change request is available at https://www.aemc.gov.au/rule-changes/application-regional-reference-node-test-reliability-and-emergency-reserve-trader

28 AEMC staff attended meetings of the IPWG as an observer.

29 AEMO, Electricity Rule Change Proposal, op cit, p. 5.

30 AEMO, Electricity Rule Change Proposal, op cit, pp 5-6.

In relation to the wording of the test, AEMO notes that "the current drafting of the RRN test has proved difficult for AEMO to interpret. AEMO proposes to improve the drafting of the test by removing double negatives and redundant cross references. These changes are not intended to alter the meaning or application of the test."[31] The rule change request includes proposed amendments to clause 3.9.3(d), set out below for ease of reference:[32]

> AEMO must continue to set *dispatch prices* pursuant to clause 3.9.2 and *ancillary service prices* pursuant to clause 3.9.2A if AEMO is satisfied that the need for the AEMO intervention event could not have been met by a direction to provide energy or market ancillary services~~given to a Registered Participant in respect of plant~~ at the *regional reference node*~~would not in AEMO's reasonable opinion have avoided the need for any direction which constitutes the AEMO intervention event to be issued.~~

The Commission considers that the proposed amendments to the clause do impact the substance of the test. The Commission's preliminary views on the issues raised by the rule change request are discussed further in Chapter 5.

2.2.2 Adjusting the $5,000 threshold for compensation

AEMO has submitted a rule change request proposing that the $5,000 compensation threshold for affected and directed participants be changed so that it applies per intervention event, rather than per trading interval. AEMO notes that, under the current approach, where an intervention event is of a long duration, the calculated participant compensation amount could far exceed $5,000 over the entire event without breaching the $5,000 threshold in an individual trading interval.

AEMO considers that "the potential for material under-compensation creates operational and financial risks for participants"[33] and that the proposed rule change would "efficiently incentivise participants to work collaboratively with AEMO without having to weigh this against the risk of financial losses from an intervention event".[34]

In considering the proposed rule change, it is appropriate to have regard to the impact of the threshold on directed participants and affected participants in turn. The Commission's preliminary views on the issues raised by the rule change request are discussed further in Chapter 6.

2.3 NEO assessment

In undertaking this investigation, the Commission will be guided by the National Electricity Objective (NEO). The Commission's assessment of the above rule change requests must consider whether the proposed rules promote the NEO as set out under section 7 of the National Electricity Law (NEL) as follows:

31 AEMO, Electricity Rule Change Proposal, op cit, p. 4.

32 ibid, p. 6. Proposed new words are underlined and strike through is used to indicate words that AEMO proposes be deleted from the current clause.

33 AEMO, Electricity Rule Change Proposal, op cit, p. 5.

34 ibid, p.6.

> 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:
>
> 1. price, quality, safety, reliability and security of supply of electricity; and
> 2. the reliability, safety and security of the national electricity system.

Based on a preliminary assessment of the issues raised by the investigation and the related rule change requests, the Commission considers that the relevant aspects of the NEO are the efficient investment in electricity services with respect to the security of the national electricity system and the price of supply of electricity.

As part of the investigation, the Commission proposes to develop recommendations for potential changes to regulatory frameworks, and to test the proposed rules, through consideration of the following propositions in relation to the promotion of the NEO:

- The normal functioning of the national electricity market provides operational and investment certainty to market participants. This leads to efficient price signals and minimises the costs of investment in the long-term interests of consumers of electricity.
- The use of interventions has a bearing on the efficiency of investment signals which impacts the costs of investments over the long term.
- Intervention pricing and compensation payments impact the price of electricity and have a bearing on the costs passed through to consumers.

2.4 Assessment approach

The Commission considers that intervention-based approaches, however well designed, are likely to be a second-best alternative to well-functioning markets at promoting economic efficiency in the long-term interests of consumers. Markets are generally the most efficient mechanism to further the interests of consumers through allowing efficient price discovery and production decisions based on competitive market dynamics. By allocating risks to market participants, markets provide financial incentives to make efficient decisions and provide incentives for innovation, to the benefit of consumers.

Indeed, as noted above, the NER include a principle that AEMO decision-making should be minimised to allow market participants the greatest amount of commercial freedom to decide how they will operate in the market.[35] Consistent with this, AEMO considers interventions to be a last resort mechanism.

Nonetheless, intervention-based approaches remain an important tool available to AEMO to help ensure reliability and system security. This is reflected in previous Commission decisions to remove sunset clauses in the NER and retain such measures indefinitely. Such measures may be particularly important when new frameworks are yet to be developed or fully implemented to support system security as the energy market transition unfolds.

35 See clause 3.1.4(a)(1) of the NER.

The intervention pricing framework in the NER is intended to maintain the efficiency of price signals that would otherwise be provided through the efficient operation of the market. However, a key question for consideration is when the application of the intervention pricing framework is appropriate.

The Commission has set out a number of principles to guide the development of recommendations on potential changes to the interventions, system strength and inertia frameworks. In addition to the NEO, these principles, together with those set out in Chapters 5 and 6, will also be used to guide the Commission's assessment of the rule change requests.

1. **Appropriate risk allocation:** Regulatory and market arrangements should be designed to explicitly take into consideration the trade-off between the risks and costs of providing a secure supply of electricity. Risk allocation and the accountability for investment and operational decisions should rest with those parties best placed to manage them. Through the use of interventions, risks are more likely to be borne by consumers. Solutions that are better able to allocate risks to market participants such as businesses who are better able to manage them are preferred where practicable.
2. **Efficiency:** The costs associated with the provision of energy resources should be assessed against the value to consumers of having a secure supply. Intervention frameworks should seek to minimise distortions in order to promote the effective functioning of the market.
3. **Flexibility:** Regulatory arrangements must be flexible to changing market and external conditions. They must be able to remain effective in achieving security outcomes over the long-term in a changing market environment. Regulatory or policy changes should not be implemented to address issues that arise at a specific point in time. Further, NEM-wide solutions should not be put in place to address issues that have arisen in a specific jurisdiction only. Solutions should be flexible enough to accommodate different circumstances in different jurisdictions. They should be effective in facilitating security outcomes where it is needed, while not imposing undue market or compliance costs on other areas.
4. **Transparency and predictability:** Interventions frameworks should promote transparency as well as being predictable, so that market participants can make efficient investment and operational decisions.

QUESTION 1: ASSESSMENT PRINCIPLES

1. Do stakeholders agree with the Commission's proposed assessment principles?
2. Are there any other relevant principles that should be included in the assessment framework?

3 INTERVENTION MECHANISMS IN THE NEM

3.1 Introduction

As discussed in Chapter 2, the changing generation mix in South Australia has led AEMO to declare system strength and inertia shortfalls. ElectraNet is currently procuring synchronous condensers fitted with flywheels in order to address these shortfalls but these are not yet in place. In the interim, AEMO is regularly directing synchronous generators to remain on line in order to ensure adequate system strength. Until such time as the synchronous condensers are installed, this need for directions is expected to remain.

In November 2018, the Energy Security Board (ESB) released a consultation paper regarding metrics for assessing the outcomes and objectives of the Strategic Energy Plan.[36] It includes the following objective: "markets operate safely, securely and efficiently, under full range of operating conditions, with minimal intervention". The proposed metrics for this objective include "system interventions < X per year", a development that may reflect increasing concern about the extent of recent intervention in the market.

The ESB's *Health of the NEM* report, released in December 2018, notes that SA interventions are lasting longer than in the past and that they "come at a significant cost to consumers". Between 2007-08 and 2016-17, directions lasted on average less than 7 hours, while in 2017-18 they lasted on average 62 hours.[37]

The current cost to consumers in South Australia of system strength directions compensation has been estimated at approximately $34 million per annum.[38] This includes part of the cost of paying compensation to both directed and affected participants, and the cost of engaging independent experts to assess claims for additional compensation. However, this figure does not take into account trading amounts retained by AEMO (which also go towards the cost of paying compensation) or the additional cost to consumers associated with higher wholesale energy costs, an issue discussed further in Chapters 4 and 7.

This chapter explains the intervention mechanisms in the NEM, including the wider context within which they operate. It discusses:

- The approach to managing reliability and security in the NEM
- The purpose, types and hierarchy of intervention mechanisms
- Key aspects of the RERT, directions, instructions and mandatory restrictions

3.2 Delivering a reliable and secure supply of energy

The Australian Energy Market Operator (AEMO) is responsible for maintaining power system security.[39] Power system security refers to AEMO scheduling and operating the power system in a secure and safe operating state, and returning the system to such a state following supply disruptions. System security deals with the technical parameters of the power system

36 ESB, *Strategic Energy Plan, Consultation on proposed metrics,* November 2018, p. 6

37 ESB, *Health of the NEM*, December 2018, p. 31

38 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 4.

39 Clause 4.3.1 of the NER.

such as voltage, system strength, frequency, the rate at which these might change and the ability of the system to withstand faults.

In order to maintain the electricity system in a secure operating state, a number of physical parameters must be controlled. Rapid changes in frequency or large deviations from normal operating frequency can lead to instability in the system. In addition, when large fluctuations in voltage occur, it is difficult for generators to remain connected to the system. Low system strength can exacerbate the magnitude of voltage fluctuations.

Large spinning synchronous generators, such as coal, gas and hydro, resist large rapid changes in frequency (by providing 'inertia') and increase system strength. These generators are synchronised to the frequency of the system and support the stability of the system by working together to maintain a consistent operating frequency and maintain the strength of the system in localised networks. Newer forms of electricity generators connected to the national electricity system, such as wind and rooftop solar, are not synchronised to the grid in the same way as synchronous generators and are, therefore, limited in their ability to dampen rapid changes in frequency.[40]

Historically, most generation in the NEM has been synchronous and, as such, the system security services provided by these generators have not been separately valued. As the generation mix shifts to more asynchronous generation, these services are not provided as a matter of course giving rise to increasing challenges in maintaining the power system in a secure state. Some asynchronous generators have capabilities to respond rapidly to sudden changes in electricity supply or demand. Currently, however, these services do not play a major role in maintaining power system security across the NEM. However, their ability to provide such services can be expected to increase in importance over time.

The shift to newer forms of generation has been more pronounced in some regions of the NEM than others. South Australia, in particular, has experienced a substantially faster change than other regions as an increasing volume of renewable energy is integrated and a number of conventional synchronous generators have recently retired. As the generation mix changes in a similar way across the NEM, the importance of new regulatory frameworks designed to support system security will increase.

System security is distinct from reliability. Reliability means that the power system has an adequate amount of capacity (generation, demand response and network capacity) to meet consumer needs. A reliable power system therefore requires adequate investment 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 wake of credible contingencies.

40 While the electrical waveform output from wind and solar generators is synchronised to the grid, the mechanical rotation of wind turbines is not synchronised to the power system.

3.2.1 How are security and reliability achieved?

The definitions of 'system security' and 'reliability' that are used in the NEM were developed prior to the commencement of the market. When the NEM was established, the roles and responsibilities of participants were developed to be consistent with these definitions. Specifically, 'reliability' issues are typically resolved by the market responding to information provided by the system operator; whereas 'security' issues are operationally directly managed by the AEMO.

The requirements for secure and reliable operating states are specified in Chapter 4 of the NER. A *secure operating state* ensures the power system is technically viable in the sense that, in the event of a credible contingency such as the failure of a transmission line or large generating unit, the power system can continue operating in a satisfactory state.[41] A secure operating state (defined in clause 4.2.4 of the NER) is an essential criterion for on-going operation of the electricity market and hence the ability to supply consumers.

A *satisfactory operating state* (defined in clause 4.2.2 of the NER) occurs when the power system is operating within the designated limits of all its components, the system is stable and circuit breakers are capable of disconnecting faulty circuits. Unless the power system is also in a secure operating state, it will not necessarily remain satisfactory following a single credible contingency event. Under clause 4.3.1 of the NER, AEMO has responsibility for maintaining power system security.

A *reliable operating state* ensures that the balance between supply and demand enables customer requirements to be met within the standards set by the Reliability Panel (clause 4.2.7 of the NER). Clause 3.9.3C(a) of the NER sets out the reliability standard for generation and inter-regional transmission elements - namely, that expected unserved energy should be limited to 0.002 per cent of the total energy demanded in a region in a given financial year.

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

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

However, additional mechanisms exist that allow for interventions to be made in certain limited circumstances when the market based arrangements have not – or will not – deliver the desired outcome. These include the Reliability and Emergency Reserve Trader (RERT) and clause 4.8.9 directions. The RERT has been activated on three occasions (once in Victoria on

41 A secure operating state is a subset of the group of satisfactory operating states. That is, a secure operating state is a satisfactory operating state, but not vice versa.

30 November 2017, once in Victoria and South Australia on 19 January 2018, and once in Victoria and South Australia on January 24-25 2019). It was also procured but not activated in NSW in June 2018. Only in two instances since 2010 has AEMO issued directions in order to achieve reliability (both were issued to a South Australian generator in early 2017).

By contrast, power system security is achieved through a combination of regulatory tools (e.g. generator technical performance standards and transmission system design requirements) and market based approaches (e.g. the provision of frequency control through market ancillary services). AEMO also uses a complex set of constraint equations within the NEM Dispatch Engine (NEMDE) to maintain power system security.

In practice, the distinction between a reliability incident and a system security incident can be blurry. For example, where demand starts to exceed supply (a reliability issue), AEMO will need to manage frequency as system security could be compromised. If frequency cannot be managed such that the system is able to accommodate a credible contingency event, then AEMO may need to intervene to maintain system security.

3.3 Overview of interventions

The purpose of interventions is to help maintain and/or re-establish the reliability and security of the NEM when regulatory processes or market responses have not delivered desired outcomes. Reliability means that the power system has an adequate amount of capacity (generator, high voltage transmission network and 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.

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 set out in clause 3.9.3C of the NER.[42] However, in operating the power system AEMO is expected to try to avoid any unserved energy (i.e. load shedding) in real time,[43] including by using the intervention mechanisms available to it if necessary.

As discussed in section 3.2, reliability in the NEM is largely driven through the spot and contract 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.[44] Furthermore, AEMO can use network support and control ancillary services (NSCAS) to the extent that the projected reserve shortfall is affected by a network limitation that can be addressed by such services.[45] If those options fail, AEMO may have no other choice but to intervene in the market more directly.

42 The reliability standard for generation and inter-regional transmission is a maximum expected unserved energy (USE) in a region of 0.002 per cent of total energy demanded in that region for a given financial year.

43 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.

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

45 Clause 3.11.5 of the NER.

AEMO has a responsibility to maintain and improve power system security,[46] defined in chapter 10 of the NER as the safe scheduling, operation and control of the power system on a continuous basis. The secure operation of the system involves compliance with technical parameters relating to issues such as frequency, voltage control and system strength even after a credible contingency has occurred, such as the loss of a single generating unit or transmission line.

Intervention mechanisms enable AEMO to deal with actual or potential supply shortages or system security issues by intervening in the market in certain limited circumstances. The fact that intervention mechanisms are considered 'last resort' powers is an attribute strongly supported by stakeholders.[47] 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 or system security issue.

From an economic perspective, the purpose of intervention mechanisms is to bring about, in certain circumstances, an outcome contrary to that which would have occurred through regulatory or market processes.

Intervention mechanisms are an acknowledged and important feature of the market design. However, the use of such mechanisms requires careful consideration as to the flow-on effects for investment signals and investor confidence, as well as costs for consumers.

Reflecting significant changes in the generation mix and the increasing challenges this has created for the system operator, the use of interventions has increased in the last two years. This has increased the spotlight on them, with growing concern about their frequent use and impacts on the market.

Intervention 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 (168.5 MW activated in total) was $51.99 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.[48] The cost of the January 2019 RERT activations are not yet known. Costs associated with the RERT are ultimately borne by consumers.

The use of directions also entails a range of costs which are passed onto consumers, including the cost of compensating directed and affected participants, and upward pressure on wholesale energy prices due to the application of 'intervention pricing'. These are explored further in Chapter 4.

Because of potential consumer cost impacts and the inherent interference with normal market functioning, the regulatory arrangements limit AEMO's powers to use interventions.

46 See s. 49 of the *National Electricity Law 1996* and clause 4.1.1(b) of the NER

47 See for example submissions made to the Reliability Frameworks Review Interim Report by AGL, Energy Networks Australia, Hydro Tasmania and Flow Power, available at https://www.aemc.gov.au/markets-reviews-advice/reliability-frameworks-review. Similar views were also expressed in response to a 2000 review of Power System Directions by NEMMCO and NECA.

48 AEMO, *Summer 2018-19 Readiness Plan,* November 2018.

For example, the RERT may only be procured if AEMO identifies a breach or potential breach of the reliability standard. If procured, the RERT can also be used for power system security reasons where practicable. Directions should only be used when the market has failed to respond to information (e.g. lack of reserve notices) provided by AEMO or where required to maintain system security.

Finally, there may be times when AEMO has no choice operationally and/or legally but to issue an instruction for involuntary load shedding[49] to maintain the power system in a secure state.[50] 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.

The RERT, directions and instructions are the three key intervention mechanisms available to maintain or re-establish power system security and/or reliability.[51] These are discussed in turn through the remainder of this chapter.

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 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 (MOU) detailing a process for the use of the emergency powers available to Ministers relating to the management of emergencies that affect the power system.[52] 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.[53]

A further mechanism, known as 'mandatory restrictions', is another means by which AEMO, acting in concert with a jurisdiction, can intervene in the market. Set out in rule 3.12A of the NER, mandatory restrictions are a form of market intervention mechanism that is proposed by a jurisdiction in instances where a significant supply demand imbalance is forecast. Mandatory restrictions are discussed further in section 3.9.

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

50 Clauses 4.2.6 and 4.3.1 of the NER.

51 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.

52 Memorandum of understanding on the use of emergency powers (2015)

53 "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.

3.4 The RERT

The Reliability and Emergency Reserve Trader (RERT) allows AEMO to contract for reserves (generation or demand side capacity that is not otherwise available to the market) ahead of a period when available supply is projected to be insufficient to meet the reliability standard.[54] At present, AEMO can contract for reserves from three hours to nine months ahead of the projected shortfall. (The Commission recently published a draft determination which, if made as proposed, would extend this to 12 months.[55]) AEMO can dispatch these reserves to ensure reliability of supply and maintain power system security, where practicable.[56] AEMO may contract only with resources that are 'out-of-market'. Examples include a back-up diesel generator or emergency demand response.

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.

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.[57]

The RERT was activated twice in 2017-18 to maintain the power system in a reliable operating state.[58] On 30 November 2017, the RERT was activated for the first time.[59] AEMO also entered into reserve contracts in January 2018 and activated the RERT in Victoria and South Australia. AEMO has noted that both short- and long-notice RERT providers were used.[60]

In June 2018, following a number of LOR2 notices in New South Wales, AEMO entered into reserve contracts (i.e. it procured the RERT) on 7 June and again on 8 June. The RERT was not activated on either day. There were no costs associated with these events.

AEMO procured the RERT in preparation for the summer of 2018-19 and activated the RERT on 24 and 25 January 2019. Detailed information on these events is not yet available.

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54 Where the RERT has been procured for reliability purposes, it can also then be used - 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.

55 AEMC, *Draft rule determination: National Electricity Amendment (Enhanced Reliability and Emergency Reserve Trader) Rule 2019*, February 2019.

56 Clause 3.20.7(a) of the NER.

57 There are three types of RERT based on how much time AEMO has to procure the RERT: the short-notice RERT is procured within seven days' and three hours' notice of a projected shortfall; the medium-notice RERT is procured between ten weeks' and one week's notice of a projected shortfall; the long-notice RERT is procured between ten weeks' and nine months' notice of a projected shortfall. See AEMC Reliability Panel, RERT Guidelines.

58 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.

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

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

3.4.1 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.[61] A number of these are also relevant to AEMO's ability to dispatch the RERT. Broadly speaking, AEMO is required to seek to minimise market distortion and maximise the effectiveness of the RERT at least cost to consumers.[62]

In particular, AEMO:

- *Is to ensure as far as reasonably practical* the number of affected participants and the effect on interconnector flows is minimised (this also applies to directions).[63]
- When procuring or dispatching the RERT must *have regard to* the following principles:[64]
  - 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 reinstatement of the long-notice RERT).[65] These provide additional guidance with respect to AEMO taking actions that have the least distortionary effect on the market, both in relation to the 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.[66]

3.4.2 Pricing under the RERT

When the RERT is activated (or when AEMO issues a direction under clause 4.8.9 - discussed further below), 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.[67] 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

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

62 Clause 3.20.2(b) of the NER.

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

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

65 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.

66 Clause 3.20.7(e) of the NER

67 Clause 3.9.3 of the NER

intervention pricing).[68] 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 Chapter 4.

3.4.3 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[69] that details matters including:[70]

- 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.[71]

The Commission's February 2019 draft rule regarding the enhancement of the RERT introduces a number of new reporting requirements, including requiring AEMO to publish quarterly reports on RERT activities.

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.[72] The Panel's analysis of market performance in terms of reliability considers, amongst other elements, the use of intervention mechanisms in the preceding year.

3.5 Directions

Reliability directions and the RERT were initially conceived as transitional mechanisms with sunset clauses. However, in 2008, the Commission extended the power to issue reliability directions indefinitely. In making its decision, the Commission concluded that reliability directions were necessary as a last resort mechanism to maintain reliability of supply, particularly in light of a projected tightening in the supply-demand balance, and to provide the market with long-term confidence that AEMO is able to intervene to avoid load shedding.[73]

For similar reasons the RERT sunset clause was removed in 2016 (rather than simply extended to June 2019, as requested by the COAG Energy Council). The Commission noted that the "final Rule preserves the safety-net feature of the RERT, and complements the suite of permanent intervention tools available to manage reliability (directions and clause 4.8.9

68 AEMO is proposing that the approach applied to directions also apply to the RERT - namely, that where the RERT is activated to address a localised issue, intervention pricing should not apply. This is discussed further in Chapter 5.

69 Clause 3.20.6(a) of the NER.

70 AEMO reporting on the RERT is the subject of the Enhancement to the Reliability and Emergency Reserve Trader rule change request.

71 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.

72 Under Clause 8.8.3(b) of the NER.

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

instructions), in the event that market responses are, or are likely to be, insufficient to service the electricity needs of consumers in a manner consistent with the reliability standard". The Commission also noted that extending the RERT indefinitely would provide regulatory certainty about the range of intervention mechanisms available to manage reliability in the NEM. [74]

When the NEM commenced in 1998, the NER distinguished between directions for breach of security, reliability and statutory obligations and applied different processes to each class of direction. For example, "what-if" pricing was implemented in connection with reliability directions but not in connection with security directions. While there remain separate references to system security directions in the NER (e.g. clause 4.8.9A), the pricing and other consequences that flow from the application of directions are now governed by a single framework.[75] This reflects that, in practice, it can sometimes be difficult to characterise a situation as either relating to a security or reliability issue, and that a reliability issue can transition quickly to a security issue.

Clause 4.8.9 of the NER allows AEMO to intervene in the market by issuing directions or clause 4.8.9 instructions (discussed below) if AEMO is satisfied that it is necessary to maintain or re-establish the power system to a secure, satisfactory or reliable operating state. Section 116 of the National Electricity Law (NEL) allows AEMO to issue directions to take certain action if AEMO considers that it is necessary to maintain power system security or for reasons of public safety.

Clause 4.8.9.(a1) distinguishes between directions (which require registered participants to take action in relation to scheduled plant[76] or a market generating unit) and instructions (which require a registered participant to take some other action - i.e. not in relation to scheduled plant or a market generating unit).

If there is a risk to the secure or reliable operation of the power system, AEMO could for example direct:

- a scheduled generator, a semi-scheduled generator or market generating unit to increase (or decrease) their output
- a scheduled load to decrease (or increase) consumption
- a scheduled network service to take certain action

unless (in the reasonable opinion of the Registered Participant that is being directed) it would be a hazard to public safety, materially risk damaging equipment or contravene any other law.[77]

74 AEMC, *Rule determination: Extension of the Reliability and Emergency Reserve Trader) Rule 2016*, June 2016, p. i.

75 Changes to the NER were made in 2002 following a review of Power System Directions by NEMMCO and NECA, the predecessors of AEMO and the AEMC respectively. See NECA Code Change Panel, *Review of directions in the national electricity market*, February 2002.

76 Scheduled plant is defined in chapter 10 of the NER as 'In respect of a Registered Participant, 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'.

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

To minimise wider market effects associated with a direction, AEMO can also impose a 'counteraction' to offset the impact 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 flows during an AEMO intervention event. For example, AEMO may direct a generator to synchronise to come to minimum load and then follow dispatch targets in order to ensure there is sufficient headroom in the system as demand increases, thereby relieving a LOR condition. To reduce the effect of the direction on interconnector flows and the number of affected participants, AEMO may constrain down output from another generator to offset the impact of the direction.

If the counteraction does not perfectly offset the effect of the direction, or where other constraints in NEMDE operate to alter dispatch targets, other participants may also have their dispatch targets affected as a result of the direction. The party which is the subject of the counteraction becomes an 'affected participant', as do any other parties whose dispatch targets are affected by the direction and subsequent NEMDE dispatch process. This is discussed further in Chapters 4 and 6.

While AEMO has power to direct a wide range of market participants, it has only ever directed generators which are scheduled, as well as two instances when directions were issued to Basslink. On both these occasions, the direction was for Basslink to turn off its frequency controller in order to maintain power system security in the NEM.[78]

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 unless to do so would, in their reasonable opinion, be a hazard to public safety, materially risk damaging equipment, or contravene any other law.[79] This clause is classified as a civil penalty provision. A compensation framework exists to enable directed participants to recover their costs. This is discussed further in Chapter 6.

3.5.1 Principles for directions

The principles AEMO must follow regarding directions are set out in the NER[80] and may be augmented by guidelines issued by the Reliability Panel (though none have been published to date). As per the RERT, these principles 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.[81]

78 Directions reports are at https://www.aemo.com.au/-/media/Files/PDF/NEM_Event_Direction_to_Basslink_11_April_13.pdf andhttps://www.aemo.com.au/-/media/Files/PDF/NEM-Event—Direction-to-Basslink-and-a-Tasmanian-Generator—16-December2014.pdf

79 Clause 4.8.9(c) of the NER.

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

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

- *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.
- *Must* observe its obligations under clause 4.3.2 concerning sensitive loads.
- *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.
- *Must* take into account any applicable guidelines issued by the Reliability Panel.
- *Should* revoke a direction as soon as AEMO determines it is no longer required.[82]

3.5.2 Pricing under directions

As with the RERT, AEMO is also required to set prices during directions to the value which AEMO, in its reasonable opinion, considers would have applied had the intervention event not occurred.[83] 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.[84] Intervention pricing is discussed further in Chapter 4.

3.5.3 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.[85] AEMO is obliged to publish this report as soon as reasonably practicable after issuing a direction.[86]

The Commission notes that, with one exception, AEMO has not published a report regarding a system strength direction since its September 2018 report describing directions issued to South Australian generators on 23-29 May 2018. The one exception is a report describing the directions issued on 29 and 30 August 2018. The publication of this report was likely prompted by CS Energy's claim in which it (successfully) disputed its liability, as an affected participant, to repay revenue to AEMO earned as a result of these directions. (This claim is discussed further in section 6.1.2.)

This delay in the publication of reports is likely to reflect the resource intensive nature of the directions process, and the fact that – as at late March 2019 – around 210 system strength directions have been issued in South Australia.[87] However this is problematic in terms of transparency and warrants additional attention and appropriate resourcing. It may be

82 Clause 4.8.9(b) of the NER. While these principles are to be reflected in AEMO's directions procedures, there are no such Reliability Panel guidelines on directions.

83 Clause 3.9.3(b) of the NER.

84 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 any of the directions issued by AEMO that constituted the intervention event.

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

86 Clause 3.13.6A(a) of the NER.

87 See market intervention notices available on the AEMO website at https://www.aemo.com.au/Market-Notices

appropriate to include in the National Electricity Rules or the intervention settlement timetable an actual time period within which such reports must be published.

The NER do not require the report to address how AEMO applied the principles governing directions. However, the Commission acknowledges that AEMO's NEM Event reports typically touch on some of the principles (for example, the requirement to minimise the number of affected participants and impacts on interconnector flows).

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.[88] Past reports examine the occurrence, nature and significance of the issuance of directions.

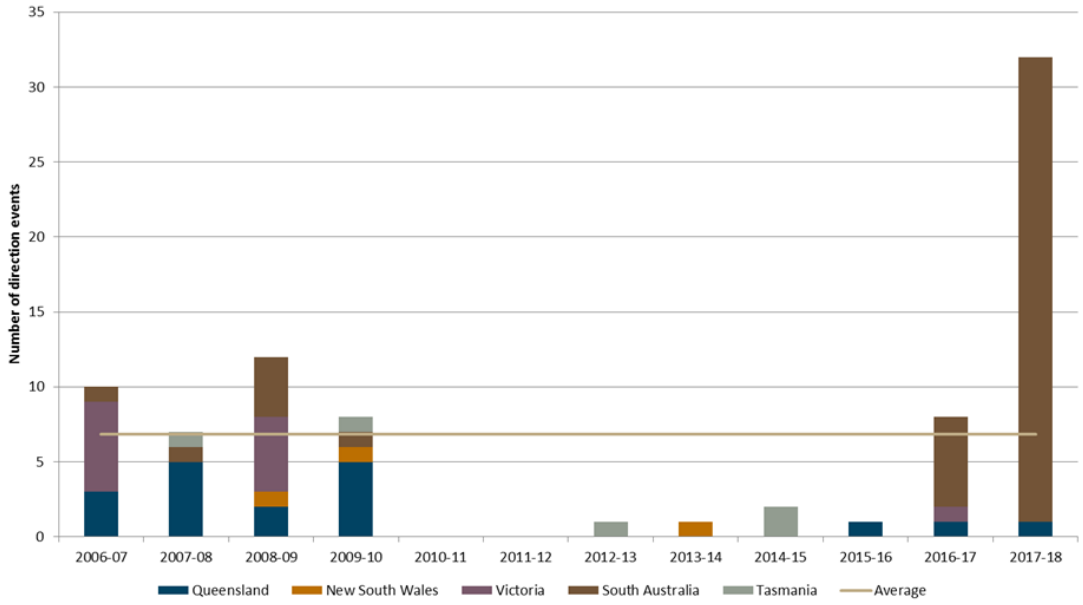
3.5.4 Recent trends in directions

The use of directions has increased markedly in recent times. Figure 3.1 presents the number of direction events since 2006-07 (as at 30 June 2018). It shows that:

- The number of direction events in the 2017-18 financial year was the highest of the past ten years. The number was four times higher than the previous financial year (32 in 2017-18 compared to eight in 2016-17).
- All but one of the intervention events in the 2017-18 financial year occurred in South Australia.
- Over the past two financial 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.

88 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 AMPR report was published on 4 April 2019 and is available on the AEMC website.

Figure 3.1: Clause 4.8.9 direction events in the NEM



Note: Data provided by AEMO. 2017-18 includes data up to 30 June 2018.

AEMO's *South Australian Electricity Report* notes that:[89]

> As at 23 September 2018, AEMO has issued over 140 directions to South Australian generator units to ensure the correct level of system strength was maintained at all times. These were security directions, for the provision of fault current, not for energy. Where AEMO issues a direction for energy, this is a reliability direction. Apart from two directions in 2017, which were for reliability/shortfall reasons, all South Australia directions have been for system strength reasons.

As at late March 2019, the number of system strength directions issued in South Australia has increased to around 210.

The proportion of time that directions have been in place in the NEM (in particular, South Australia) has also risen noticeably. In 2017-18, a direction event was in force on average 159 hours per month while in 2016-17 the average figure was seven hours per month.

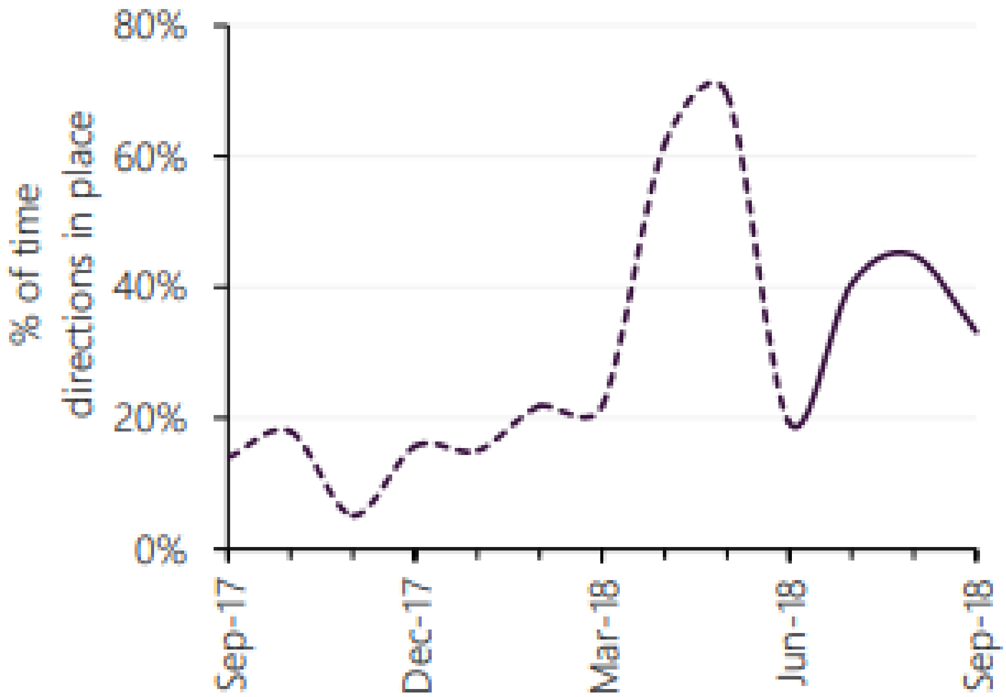
Figure 3.2 shows the percentage of time that directions were in place in South Australia since September 2017. On average, directions were in place for around 40 per cent of the time during the third quarter of 2018, 50 per cent of the time in the second quarter of 2018,[90] and 30 per cent of the time since the system strength unit combinations were introduced in September 2017.[91]

89 AEMO, *South Australian Electricity Report*, November 2018, p. 53.

90 Notably, directions were in force for over 60 per cent of the time during April and May 2018.

Key drivers of system strength directions during the quarter included periods of relatively low prices (<$50/MWh) and high wind output (>1,100 MW) which resulted in synchronous generators seeking to decommit from the market for commercial reasons.[92] This is discussed further in section 6.4.

Figure 3.2: System strength directions in South Australia



AEMO, *Quarterly Energy Dynamics - Q3 2018*, November 2018, p. 7

3.6 Instructions

An instruction differs from a direction in the nature of the action taken. Clause 4.8.9(a) and (a1) of the NER provide that AEMO is taken to have issued a direction where it requires 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. Where the action to be taken does not relate to a scheduled plant or market generating unit, AEMO is taken to have issued a 'clause 4.8.9 instruction'.

Instructions generally involve AEMO requiring a network service provider or a large energy user to temporarily disconnect its load or reduce demand if there is a risk to the secure or

91 AEMO, *Quarterly Energy Dynamics - Q3 2018,* November 2018, p. 7

92 ibid.

reliable operation of the power system.[93] AEMO may also instruct a network service provider to shed and restore load consistent with schedules provided by the relevant state government.[94]

The categories of registered participants that can be subject to an instruction 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".
- 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.[95] Currently there are 76 registered market customers, the majority of which are retailers.[96]
- 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.
- 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.

The trigger for 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.[97] As an instruction typically involves load shedding, it is fundamentally a mechanism for maintaining or returning the system to a secure operating state.

Instructions oblige instructed parties to use reasonable endeavours to comply. As with directions, they are a non-voluntary form of intervention.[98]

Instructions to shed load are issued infrequently. AEMO issued instructions to shed load in South Australia on 8 February 2017 and in NSW on 10 February 2017. In January 2019, there were two further instances of load shedding. While detailed information is not yet available, the Commission understands that instructions to shed load were issued.

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

94 Jurisdictions manage the impact of instructions in advance by providing a load schedule, including sensitive loads, which sets out the order in which AEMO may shed load under rule 4.8: see clause 4.3.2(f) of the NER.

95 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

96 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).

97 Subsequent to complying with the sequence of steps set out in clause 3.8.14 during times of supply scarcity (i.e. activating the RERT, if it has been procured, ahead of using directions or instructions).

98 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).

3.6.1 Principles for instructions

During a supply scarcity event, AEMO must comply with the sequence of steps outlined in clause 3.8.14 - namely, in the event of supply scarcity, AEMO is to dispatch all valid bids and offers from the market, then dispatch the RERT (if it has been procured) before issuing directions or instructions. Additionally, there are requirements in the rules for AEMO to use reasonable endeavours to shed load across regions in an equitable manner, as specified in the power system security standards,[99] and to maintain supply to sensitive loads.[100]

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.[101]
- 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.[102]
- 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.[103]

3.6.2 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.[104] 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 in Chapter 4.

As discussed in section 4.6, some stakeholders have suggested that this same approach (setting the spot price to the market price cap) should also be used when the RERT is activated (in lieu of intervention pricing).

3.6.3 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.[105] 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.*[106] AEMO must also prepare a review report and make it available to

99 Clause 4.8.9(i) of the NER.
100 Clause 4.3.2(f) of the NER.
101 Part 8, section 114 of the National Electricity Law.
102 Clause 4.8.9 (i) of the NER.
103 Clause 4.8.9 (j) of the NER.
104 Clause 3.9.2(e)(1) of the NER.
105 Reporting on instructions is addressed in Clause 4.8.15 while reporting on directions is clause 3.13.6A.

Registered Participants and to the public.[107] Registered participants must co-operate in any review conducted by AEMO, including making records and information available.[108]

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.

3.7 Principles underpinning the intervention mechanisms

There are subtle differences between the principles that constrain and guide AEMO's use of each intervention mechanism (discussed in sections 3.4.1, 3.5.1 and 3.6.1). For instance, the principle regarding minimising the cost of the RERT cites both maximising effectiveness and minimising cost to end use consumers of electricity.[109] The obligation on AEMO in relation to directions does not directly mention end use consumers in relation to minimising costs (and compensation).[110] AEMO is to 'have regard to' the RERT cost principle and apply the higher bar of 'reasonable endeavours' to meet the directions cost principle.[111]

Noting that each intervention mechanism has different characteristics, 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. On the other hand, there may be benefit in amending the principles to promote internal consistency to the extent appropriate.

> QUESTION 2: PRINCIPLES APPLICABLE TO THE INTERVENTION MECHANISMS
>
> Are any changes to the intervention mechanism principles warranted?

3.8 Hierarchy of intervention mechanisms

Clause 3.8.14 of the NER establishes a two-level hierarchy for the use of the intervention mechanisms. In times of 'supply scarcity', after dispatching all valid bids and offers, AEMO must use reasonable endeavours to first exercise the RERT (if it has been procured) and then, if necessary, issue either directions or instructions.[112] The term 'supply scarcity' is not defined in the rules and is used only in clause 3.8.14. As such, the term is to be read with its plain meaning – namely, periods during which there is a shortage or shortfall of supply.[113]

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

107 Clause 4.8.15(c) of the NER.

108 Clause 4.8.15(e) of the NER.

109 The Commission's draft rule regarding enhancement of the RERT introduces a payment guide for the RERT. The guide reflects the principle that AEMO should only use the RERT if it is cheaper than involuntary load shedding.

110 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.

111 Clauses 4.8.9(b)(1) and 3.20.2(b) of the NER.

112 The sequence to be followed under clause 3.8.14 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 the 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 rule 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).

The NER do not specify a priority as between directions (which require registered participants to take action in relation to scheduled plant and market generating units) and instructions (which require registered participants to take action other than in relation to scheduled plant and market generating units). 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'.[114] In practice, however, AEMO uses directions first (for example, to manage an actual or forecast LOR2 condition) and instructions to shed load only very rarely (as a last resort to maintain system security when a LOR3 condition occurs).[115]

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 circumstances to follow the sequence under clause 3.8.14.

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)"[116] and "any plant operating restrictions associated with a relevant AEMO intervention event".[117]

An important question is whether this hierarchy of intervention – i.e. RERT first, then directions and/or instructions – delivers the best outcomes for consumers.

Assuming that RERT contracts are procured at a cost less than the VCR of those customers whose load would likely have been shed had the RERT not been activated, activating the RERT before issuing an instruction to shed load can be expected to deliver efficient outcomes.[118]The RERT represents a voluntary arrangement for out-of-market resources to generate energy or reduce demand, and so should (subject to the above qualification as to cost) be preferable to instructions that lead to the involuntary shedding of load.

The Commission's draft rule to enhance the RERT seeks to embed efficient outcomes by requiring AEMO to use reasonable endeavours to ensure that the average amount payable under RERT contracts does not exceed the 'estimated load shedding VCR' for the relevant region.[119] 'Estimated load shedding VCR' is defined as the average VCR associated with those loads that AEMO reasonably expects would likely have been shed had AEMO not exercised the RERT, having regard to the priorities set out in the relevant load shedding procedures.[120]

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

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

115 A lack of reserve (LOR) 2 condition signals a tightening of electricty supply reserves and the need for more generation to be available. An LOR3 condition signals a deficit in the supply/demand balance. At such times, load shedding may be required to keep the system secure. AEMO publicly states that it views load shedding as an 'absolute last resort' – see AEMO, *Summer 2017-2018 Operations Review*, May 2018, p. 17.

116 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.

117 See clauses 3.8.14(a)(1) and (2) and 3.8.14(b)(1) and (2) of the NER. An AEMO intervention event is defined as exercising the RERT and issuing a direction: chapter 10 of the NER. It does not include issuing an instruction.

118 The value of customer reliability (VCR) is an AER estimate of the value to customers of a reliable electricity supply. See https://www.aemc.gov.au/rule-changes/establishing-values-of-customer-reliability

119 See clause 3.20.3(k)(3) in Draft National Electricity Amendment (Enhancement of Reliability and Emergency Reserve Trader) Rule 2019.

This is designed to manage the costs of the RERT and ensure that its use does not impose inefficient costs on consumers.In particular, where the relevant customer VCR is lower than the cost of the RERT, it would be more efficient to shed such load, rather than exercise the RERT at very high cost.

The rationale for prioritising the RERT over directions (specifically directions to procure energy) is less obvious than the rationale for exercising the RERT ahead of instructions (where the cost of the RERT is lower than the relevant VCR). Both directions and RERT are interventions in the energy market. Holders of RERT contracts have agreed to be activated under contracts; market participants have agreed to be participants in the NEM, fully aware that powers of direction powers are available to AEMO. It follows that there is no obvious reason that one should be preferred to another, except for cost. From a consumer perspective, consumers have no choice as to whether electricity supplies are secured using the RERT or directions but are nonetheless liable to pay for the costs of whichever intervention mechanism is deployed.

It is reasonable to expect that directing in-market generators may deliver reliability outcomes at costs lower than those associated with dispatching out-of-market reserves. This is because, under clause 3.15.7(c), generators who are directed to provide energy or market ancillary services are compensated for the services they provide at the 90th percentile price. (While they also have the option to make a claim for additional compensation if they are still out of pocket, such claims are made only rarely.)

It is unlikely that out-of-market reserve providers would deliver services under the RERT at a cost lower than this. If this were the case, such parties could be expected to provide services profitably in the market under normal conditions. Parties providing services under the RERT are eligible to receive a number of different payments - for being available, for pre-activation and, finally, activation. Experience to date demonstrates that the RERT can entail high costs even when activated for periods of short duration, as shown below.

Figure 3.3: RERT costs in 2017-18

RERT costs associated with 2017-18 financial year ($ million)

	Availability payments	Pre-activation costs	Activation costs	Other costs A	Total costs B
RERT costs in financial year 2017-18	$27.03	$ 21.56	$3.23	$0.17	$51.99

A. "Other costs" represent 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.

B. Costs are passed through to Market Customers in the relevant region in accordance with the NER.

Source: AEMO, *RERT 2017-18 Cost Update,* available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/RERT-Update—-cost-of-RERT-2017-18.pdf
Note: These costs were incurred for two activation periods which totalled 12 hours.

120 Ibid, see draft clause 3.20.1(b)

AEMO could face this type of potential trade-off between RERT and directions. For example, in 2017 AEMO issued directions to Pelican Point power station on 9 February and 1 March. Both directions were issued for reliability reasons – i.e. because of forecast LOR2 conditions in South Australia.

At the time, no RERT contracts had been procured in South Australia, and so no choice had to be made between directing and RERT. However, AEMO has now procured RERT in South Australia.[121] Under the current provisions, if faced with the same conditions – i.e. a forecast lack of reserve with Pelican Point (or some other generator) bidding unavailable – AEMO would have to activate the RERT contracts prior to calling upon Pelican Point (or another generator), regardless of the relative costs of each option. Given that the directed generator would have been compensated for its output at the 90th percentile price (which at the time was in the order of $137/MWh) it is reasonable to conclude that the cost of directing the generator would have been significantly lower than the cost of activating the RERT.

While most generators will be incentivised to participate in the market when the supply demand balance is tight and the spot price high,[122] it is possible that generators will remain available for direction, as was the case with Pelican Point. This may be, for example, because the generator considers that it will be unable to recover its start and/or fuel costs if a projected shortfall is only of short duration and has therefore bid unavailable.

In considering the optimal hierarchy of intervention mechanisms, it is relevant to consider that directions may be capable of faster implementation than the RERT and this is valuable: delaying the issue of directions for as long as possible provides the greatest possible time for the market to respond and thus avoid the need for the intervention, or for circumstances to change such that the intervention is no longer required. (For example, temperatures and demand may not reach forecast levels, meaning that no direction or out-of-market reserves are required to ensure reliability.)

By contrast, activating the RERT may involve pre-activation as well as activation costs, minimum notice periods and minimum run times. Given this, prioritising the RERT over directions may result in an approach that is more blunt in an operational sense and more costly for consumers.

QUESTION 3: HIERARCHY OF INTERVENTION MECHANISMS

1. What is the ideal hierarchy of intervention mechanisms, i.e. the order in which AEMO should use the RERT, directions and instructions to shed load?
2. Should the current hierarchy of intervention mechanisms be changed so that the RERT is no longer preferred to directions?

121 AEMO, *Summer 2018-19 Readiness Plan*, November 2018, p 4.

122 Evidenced by the fact that reliability directions have only been issued on two occasions since 2010, while system security directions are now frequent.

3. Should a reasonable endeavours 'least cost' principle inform the hierarchy of intervention mechanisms?
4. What are the potential advantages and disadvantages of making such a change?
5. Should the same hierarchy apply in the case of both a system security event and 'supply scarcity'?

3.9 Mandatory restrictions

In late January and early February 2000, the supply of electricity in Victoria, NSW and South Australia was disrupted by a combination of technical issues and industrial action. On 23 January 2000, units at Bayswater, Mount Piper and Torrens Island power stations tripped in quick succession leading to a loss of over 1,400 MW or 10 per cent of demand.[123] In the first few weeks of February, the impact of industrial action at Yallourn was exacerbated by record high demand. As a result, demand exceeded supply in Victoria and South Australia and significant load shedding occurred in each region. On 4 February, Victoria imposed demand restrictions which continued until 10 February 2000.[124]

When restrictions are imposed on a region, electricity users are requested to reduce demand (and large electricity users may be *required* to reduce demand). This reduces the quantity of electricity traded, the spot price, and thus the revenue earned by generators. The level of demand response that will be achieved by restrictions is difficult to estimate and the actual response by consumers may be greater than is necessary. The reduction will not count towards the relevant jurisdiction's share of inter-regional load shedding and, perversely, would reduce the spot price at the height of a shortfall.[125] This is in contrast to the approach whereby the spot price is set to the market price cap if involuntary load shedding occurs.

In July 2000, the National Electricity Code Administrator (NECA – the predecessor of the AEMC) investigated integrating demand restrictions into the market in order to preserve price signals and ensure that market prices during such periods provide an appropriate incentive for new investment in generation and demand side management schemes.[126] This investigation also recommended changes to the market pricing provisions in order to clarify how prices should be set during extreme events.

Following the investigation, new provisions under Rule 3.12A were added to the NER to incorporate mandatory restrictions in the centralised dispatch and pricing process. Mandatory Restrictions are a market intervention mechanism, whereby restrictions are imposed by a jurisdiction[127] and the pricing mechanism is applied by AEMO in instances where a supply demand imbalance is forecast. The NER defines mandatory restrictions as "restrictions

123 NECA, I*nvestigation into the Market's Performance in Extreme Conditions*, July 2000

124 ibid.

125 ibid.

126 ibid.

127 The *National Electricity Market – Memorandum of Understanding on the Use of Emergency Powers 2015* defines jurisdictions as NSW, VIC, QLD, SA, ACT and TAS or any other party who becomes party to this memorandum.

imposed by a participating jurisdiction, by a relevant law, other than the rules, on the use of electricity in a region"*.*

Mandatory restrictions on the use of electricity may be imposed by a jurisdiction as a means of controlling demand and averting a situation where there is insufficient generation capacity to meet demand, particularly in situations where mandatory load shedding is or would otherwise be necessary. These restrictions may come into effect during periods of extreme demand or instances where a sudden decrease in available capacity occurs, for example due to industrial action.

An example of a relevant state law is the *Electricity Supply Act 1995* (NSW). Amendments were made to that Act following the February 2017 heatwave during which the NSW Government publicly encouraged customers to reduce demand.[128] These amendments were designed to provide the NSW Government with the streamlined and updated tools needed to take action in the management of an electricity supply emergency. The provisions recognise that AEMO has primary responsibility for managing electricity emergencies but are designed to support AEMO. For example, they empower the Minister to direct persons or corporations who are not registered participants in the NEM, thus assisting AEMO by undertaking actions that are beyond AEMO's remit.[129]

The *Electricity Supply Act* amendments outline when directions can be issued and the terms by which they can be varied and revoked. Section 94B(2) provides that *"*electricity supply emergency directions may be given (…) to restrict the use of electricity in order to reduce demand"*.* Directions may require large users of electricity to wholly or partly turn off or shut down any plant of equipment for a specified period of time: s94B(2)(b).Failure to comply with a direction is an offence. The state is not liable to pay compensation for any loss resulting from the use of electricity supply emergency directions: s179A (1B).

Rule 3.12A of the NER outlines how mandatory restrictions are to be implemented. It includes provisions relating to restriction offers, mandatory restrictions schedule, acquisition of capacity, rebid of capacity, dispatch of restriction offers, pricing during a restriction price trading interval, determination of funding restriction shortfalls, cancellation of a mandatory restriction period, and review by the AEMC. The provisions are designed to integrate mandatory restrictions into the market to ensure the delivery of a reliable and secure power supply. This is achieved through a combination of capacity contracting and a refinement to the 'what-if' pricing arrangements used to preserve price signals during interventions in the market.[130]

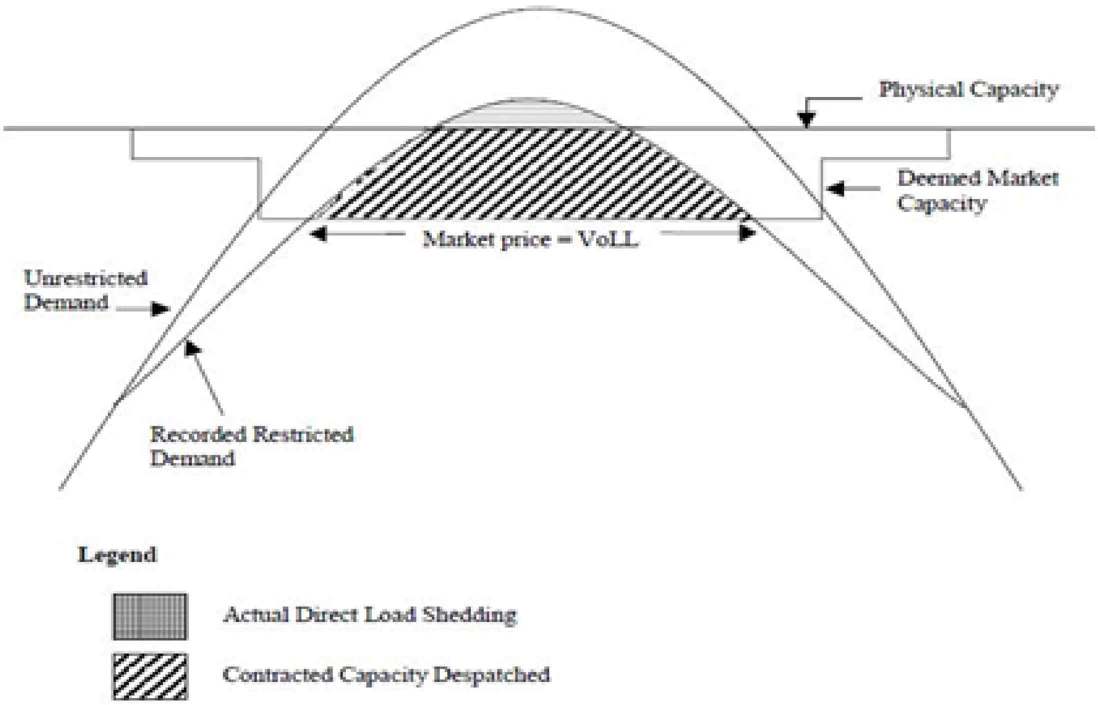
128 AEMO, *System Event Report New South Wales,* 10 February 2017

129 The second reading speech for the *Electricity Supply Amendment (Emergency Management) Bill 2017* notes that 'in the majority of situations, the Australian Energy Market Operator can take the necessary action and does not require intervention from the New South Wales Minister. However, if the Australian Energy Market Operator is not able to do what is needed because of limits on its powers, AEMO may require assistance from within New South Wales. Some examples where a New South Wales energy Minister may be asked to assist include: where directions must be given to persons other than registered participants in the national electricity market and AEMO requests that New South Wales declare an electricity supply emergency and exercise its local emergency powers; or where a power supply disruption is likely to have an extended duration requiring mandatory restrictions for the broader community, including exemptions for vulnerable consumers. The powers needed by the New South Wales Minister for energy are not likely to be used frequently, but when they are needed, they must operate quickly and effectively." Available at https://www.parliament.nsw.gov.au/bill/files/3455/2R%20Electricity%20Supply%20Amdt.pdf

130 Australian Customer and Competition Commission, *Pricing under Extreme Conditions: Final Determination,* September 2001

When restrictions are declared upon electricity usage in a region, AEMO will be required to call for sufficient capacity contracts ('restriction offers') equal to the estimated reduction in demand due to the restrictions. Capacity can be offered by any participant (generators and market network service providers) already presenting to the market. The scheduled capacity, equivalent to the reduction in demand due to the restrictions, would be contracted to AEMO and withdrawn from the market for pricing purposes for the duration of the restrictions as shown in figure 3.4 below. This scheduled capacity would remain available for dispatch at the market price cap once all other options, including scheduled loads, have been exhausted. This is designed to avoid the outcomes seen in early 2000, where anecdotal reports indicate that demand response was so significant during this period that the resulting fall in the spot price led to generation being exported from Victoria to South Australia and NSW which had not implemented restrictions.

Figure 3.4: Integrating restrictions into the market



Source: NECA, Investigation into the Market's Performance in Extreme Conditions, July 2000. Clause 3.12A.1(a) of the NER requires AEMO to develop a 'mandatory restrictions trading system' in accordance with the Rules consultation procedures.The trading system must include procedures for the acquisition of capacity, restriction offer, standard terms and conditions, procedures for funding restriction shortfalls and procedures for rebidding and dispatch of capacity.

AEMO has developed a Mandatory Restriction Offers Procedure (2015) which explains the restriction offer process and outlines the arrangements for dispatching mandatory restriction offers when restrictions are declared in a jurisdiction.[131] The following extract from the procedure summarises the market operation when restrictions are declared:

131 AEMO, *Mandatory Restriction Offers Procedure SO_OP_3713,* November 2015

- **Mandatory restriction initiation:** The Mandatory Restriction offer process should commence only after AEMO formally receives advice from the Jurisdictional System Security Coordinator (JSSC) that the Jurisdiction proposes to invoke mandatory restrictions
- **Mandatory restriction schedule:** Once formal advice has been received, AEMO issues a market notice informing the market that a decision has been made to impose mandatory restrictions in participating jurisdiction(s). AEMO will, within four hours of receiving advice from the JSSC, prepare a Mandatory Restriction Schedule and forward it to the JSSC for approval. The schedule is a half hourly schedule detailing the forecast load for the region (unrestricted load profile) and the forecast load including mandatory restrictions (restricted load profile).
- **Market management systems:** The JSSC is responsible for amending and approving the mandatory restriction schedule. Once approved, AEMO will submit the mandatory restriction schedule to the market management systems.
- **Mandatory restriction offer submission:** After the approved mandatory restriction schedule has been submitted to the market management systems, AEMO will issue a market notice informing the market of the offer cut off time and request participants to submit market restriction offers.
- **Mandatory restriction eligibility:** AEMO must only accept restriction offers from scheduled generators and scheduled network providers with a connection point in the region in which mandatory restrictions apply in accordance with clause 3.12A.1(b)(8) of the NER.
- **Mandatory restriction ineligibility:** Generating units and some market network service providers that have access to their regional reference node constrained by intra-regional constraints will be deemed ineligible to offer mandatory restrictions.
- **Mandatory restriction dispatch:** Participants will have a minimum duration of two hours by which to submit mandatory restriction offers after which AEMO will de-authorise ineligible offers and validate eligible offers. A mandatory restriction offer stack will be determined for each trading day and used to accept mandatory restriction offers for each region to meet the mandatory restriction schedule.
- **Submit Mandatory restriction offers:** Once AEMO has determined the mandatory restriction schedule has been satisfied by accepted mandatory restriction offer capacities, offer quantities will be submitted to the market management system.
- **Load forecasting:** Initially**,** load forecasts will be submitted by AEMO for regions under consideration without taking into consideration the effects of the mandatory restriction. Once approved mandatory restriction offers have been dispatched and submitted, load forecasts reflecting the mandatory restrictions will be sent to the market management system.
- **Monitoring mandatory restriction offer dispatch:** The JSSC and AEMO are responsible for monitoring the mandatory restriction schedule. Market network service

providers and generators are responsible for informing AEMO of any deducted mandatory restriction capacity.[132]

3.9.1 Issues arising with respect to mandatory restrictions

Mandatory restrictions have been designed to minimise the extent of involuntary load shedding and improve the arrangements for determining reserve thresholds consistent with the standards set by the AEMC Reliability Panel.

The concept of integrating restrictions into the market to preserve scarcity price signals and balance supply and demand under extreme market conditions was supported in principle by stakeholder submissions during the proposed code change.[133] However, a number of stakeholders expressed concern about estimating demand reduction, unmanageable risk created for market customers, recovery of costs based on beneficiaries in mandatory restriction periods, gaming by customers, and jurisdictional intervention.

Submissions identified that the challenge of accurately estimating the likely impact of restrictions would distort outcomes and not achieve the intended outcome.[134] An overestimation of the demand reduction due to restrictions would cause a situation where the spot price is set at the MPC for an extended period which could have a major impact on market customers, particularly those who are not fully hedged. While an extended period of prices at the MPC will eventually exceed the cumulative price threshold and trigger an administered price period (effectively capping retailers' market risk), risk exposure in the interim period could nonetheless be significant. Contract prices could rise as there are incentives for generators to become less hedged and retailers to become more hedged.[135]

The Australian Competition and Consumer Commission (ACCC) considered the above issues in its final determination. It concluded that the proposed amendments to the Code were likely to result in a benefit to the public which outweighed the potential detriment from any lessening of competition that would result if the proposed conduct or arrangements were made or engaged in.[136]

Mandatory restriction pricing arrangements have not been applied in any of the jurisdictions to date.[137] However, the ageing generation fleet and the increasing frequency and intensity of extreme weather events may lead to situations where jurisdictions need to reduce demand when a projected shortfall is not expected to be met through market responses and/or the RERT and the extent of involuntary load shedding is considered unacceptable from a jurisdictional perspective. As such, relevant questions arise as to whether the mandatory

132 Deducted capacity means a generator who has committed capacity as part of a restriction offer and now (possibly due to technical issues) has to reduce the capacity it originally offered.

133 ACCC Determination, *Amendments to the National Electricity Code*, September 2001, available at https://www.accc.gov.au/system/files/public-registers/documents/D03%2B38144.pdf

134 ibid.

135 ibid.

136 ibid

137 In this regard, it is worth noting that the market has changed significantly since rule 3.12A was included in the NER, particularly with respect to demand response and proposals to introduce a demand response mechanism. If introduced, such a mechanism would facilitate demand reductions in response to tight supply conditions and may - in conjunction with the enhanced RERT - reduce the need to activate the mandatory restrictions process, all else being equal.

restrictions framework should be retained, and if so, whether the framework should be amended.

Removing the framework would mean relying on the operation of the spot market (supported by the RERT and directions) to enable participants on both the supply and demand side to respond to price signals, even in extreme conditions. The rationale for introducing the mandatory restrictions framework was to preserve price signals during a period where demand is reduced as a result of restrictions and provide an incentive for generators to invest and increase supply. The framework was designed to avoid situations similar to that which arose in Victoria in 2000 when the response to restrictions was greater than expected, resulting in a significant fall in the spot price and energy being exported to other regions.

The application of mandatory restrictions may result in outcomes that would leave market customers worse off than if restrictions and related pricing procedures had not been imposed. For example, errors in the estimation of demand reduction due to restrictions may result in price outcomes that are on average higher than would have occurred had the estimate of demand reduction due to restrictions been accurate[138]. Alternatively, market customers (and their consumers) may have to bear AEMO's costs of contracting generation capacity even if it is not ultimately required due to the level of demand response achieved in response to restrictions.

Given this, it may be preferable to use intervention pricing (as used for the RERT and directions) as the means to preserve scarcity price signals rather than require AEMO to contract for capacity (which, if dispatched, is priced at the MPC) independently of the normal dispatch process.

This may be more transparent, less blunt and less challenging to implement than the mandatory restrictions approach. The intervention price could reflect the level that the spot price would be expected to reach in the absence of any jurisdictionally imposed demand restrictions. This would serve to preserve scarcity price signals without the need to contract for capacity outside of the normal dispatch process.

QUESTION 4: MANDATORY RESTRICTIONS

1. Should the mandatory restrictions framework be retained?
2. Should the mandatory restrictions framework be amended in any way? For example, would it be preferable to use intervention pricing (as used for the RERT and directions) as the means to preserve scarcity price signals rather than require AEMO to contract for capacity (which, if dispatched, is priced at the MPC) independently of the normal dispatch process?

138 NECA, *Industrial Relations Force Majeure event in Victoria,* January 2000

4 INTERVENTION PRICING

4.1 Introduction

This chapter, together with Chapter 6, explains two related but separate frameworks relating to pricing and compensation. These frameworks are triggered when AEMO intervenes in the market by activating the RERT or (in certain circumstances[139]) issuing a direction. 'Intervention pricing' determines the price at which the market clears during an AEMO intervention event[140], while compensation is a separate process and is paid only to certain parties – those who are directed to provide services and those who are affected (i.e. dispatched differently) due to the direction. Compensation is payable regardless of whether intervention pricing is implemented.

Intervention pricing as defined in the NER 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.[141] This can be considered a form of intervention pricing in its broader sense, but is not intervention pricing as defined in the NER.

This chapter examines

- the role of intervention pricing in connection with the RERT and directions
- when intervention pricing applies and how it works
- whether intervention pricing is distorting price signals when used in connection with system strength directions
- AEMO's review of intervention pricing

The compensation framework is discussed in Chapter 6.

4.2 The role of intervention pricing

As noted in sections 3.4.2 and 3.5.2, 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.[142] 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?

AEMO determines the intervention price in accordance with an intervention pricing methodology developed under clause 3.9.3(e). As the methodology notes, the aim of intervention pricing is 'to preserve the market signals that would have existed had AEMO not intervened'.[143] Such signals are important, particularly in an energy-only market, as they are designed to convey to stakeholders the need for investment in additional capacity. In this

139 Intervention pricing does not apply if the direction relates to a localised rather than region-wide issue.

140 Defined in chapter 10 of the NER as issuing a direction or exercising the RERT. Clause 4.8.9 instructions are not included in the definition of an AEMO intervention event.

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

142 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.

143 AEMO, *Intervention Pricing Methodology*, September 2018, p. 5

way, intervention pricing seeks to minimise the market distortion that would otherwise result from the intervention.

4.3 When does intervention pricing apply?

Clause 3.9.3(a) of the NER provides that, in respect of a dispatch interval where an AEMO intervention event occurs, AEMO must declare that dispatch interval to be an 'intervention price dispatch interval'. This declaration is to be made as soon as the intervention occurs and regardless of whether intervention pricing is in fact applied, a requirement that has the potential to create confusion and one that also has implications for the entitlement of affected participants to compensation (discussed further in Chapter 6). Given this, there may be merit in clarifying this provision: for example by referring to 'intervention dispatch intervals' where a decision to intervene has been made, and only referring to 'intervention price dispatch intervals' once a decision has been taken to implement intervention pricing.

When the intervention event comprises a direction (rather than the activation of the RERT), AEMO is required to determine whether to implement intervention pricing. Specifically, AEMO must decide whether the test set out in clause 3.9.3(d) is met. That provision states that AEMO must continue to set prices using normal processes (and not implement intervention pricing) 'if a direction given to a registered participant in respect of plant at the regional reference node would not in AEMO's reasonable opinion have avoided the need for any direction which constitutes the AEMO intervention event to be issued'.

This test is known as the 'regional reference node test' (RRN test) and its intent has been described as follows:[144]

> For some interventions the Rules [clause 3.9.3(d)] provide that intervention pricing is not invoked and normal price setting continues. These circumstances apply in situations where equivalent intervention in respect of plant located at the regional reference node would not have removed the need for the intervention actually given. Thus, if a generator is directed to operate its generating plant to address a supply deficiency that is confined to a part of the network that does not include the regional reference node, then intervention pricing is not invoked. This might occur for example if a network constraint was restricting supply to a remote area near the directed generator.

The origin of the test lies in changes made to the directions framework as it existed when the NEM commenced operation in 1998. At that time, the National Electricity Code (the predecessor of the NER) included separate frameworks for directions relating to breach of reliability, security and statutory obligations. Intervention pricing was implemented for directions relating to reliability but not in relation to security directions.

A review of directions was undertaken jointly by NEMMCO and NECA in 2000.[145] It made a number of recommendations that are relevant to this review, including that:

144 AEMO, *Briefing Paper: Operation of the intervention Price Provisions in the National Electricity Market*, March 2011, p. 4.

145 NEMMCO and NECA, *Power system directions in the National Electricity Market*, May 2000.

- directions should be employed only as a last resort and in the event that normal market mechanisms have failed, or are not in place, to achieve a secure, satisfactory or reliable operating state or in response to statutory obligations, e.g. in relation to public safety
- the separate arrangements for reliability, security and statutory obligation directions should be consolidated into a single common arrangement, thereby reducing the level of discretion required to be exercised by NEMMCO
- in the event of a direction, market prices should so far as practicable be set on a 'what-if' basis in order to retain the appropriate price signal in the market and provide an incentive for market-based response in the future
- directed parties should be entitled to receive 'fair payment' at a level that at least covers the cost incurred in complying with the direction
- third parties whose market dispatch is affected by a direction should be compensated so that their financial position is unaffected by the direction.[146]

The report further noted that, in applying 'what-if' pricing, a distinction should be drawn between 'regional and local directions'. It stated:[147]

> A regional deficiency may be redressed by a direction to a participant anywhere in the region. Use of a what-if price for the region will therefore signal the region wide deficiency. On the other hand, a localised deficiency can only be redressed locally. As there is no regional deficiency it is inappropriate for the regional market price to indicate a shortfall, in fact the regional what-if price will be broadly the same as the 'outturn' price (that is, the spot price when there is no attempt to offset the effects of the direction). Market clearing prices are however based on a regional model of the market and cannot readily determine the impact of localised directions. Accordingly, what-if prices will not be calculated for localised directions.

The wording of the current RRN test does not clearly articulate or reflect this original policy intent. Instead, its reference to 'plant at the regional reference node' has prompted decisions to be made based on the physical circumstances pertaining to each case, rather than on whether the application of intervention pricing in a given case is consistent with the policy intent underpinning the test.

Given the difficulty to date in applying the test, AEMO has submitted a rule change request seeking to amend the provision in order to improve clarity and extend the reach of the test to encompass the RERT (in addition to directions). If made as proposed, this rule change would mean that, if the RERT were to be activated in order to address a localised rather than region-wide issue, intervention pricing would not apply. The test and the AEMO proposal are discussed in detail in Chapter 5.

146 ibid, p. i
147 ibid, p. ii

4.4 How does intervention pricing work?

If AEMO decides that the RRN test is met, intervention pricing is used to determine prices for energy and market ancillary services in every dispatch interval (being five minutes in duration)[148] impacted by the intervention. An AEMO intervention event may consist of a large number of dispatch intervals (up to three weeks in one instance)[149] 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" or "dispatch run") and once to determine intervention prices for energy and market ancillary services (the "what-if run" or "intervention pricing run"). This process happens every five minutes. Generators are dispatched in accordance with the dispatch 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 dispatch levels determined in the what-if run are combined with dispatch offers to calculate a clearing price that reflects the price that AEMO considers would have prevailed had the direction not been issued.[150]

The dispatch 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.[151] The what-if run does not include the direction or RERT activation, or any counteractions implemented to reduce their flow on effects.

Counteractions are designed to offset and thereby limit the wider impact of a direction. Clause 3.8.1(b)(11) of the NER requires AEMO to ensure that, as far as reasonably practical, the number of participants affected by an intervention event and the resulting effect on interconnector flows are minimised. In practice and where possible, AEMO complies with this provision by selecting generating units located in the same region as the directed generator (and, if possible, at the same power station as the directed unit, or another power station belonging to the same participant). It then constrains the dispatch of the selected generating unit/s by an amount that, as closely as practical, matches the amount of energy provided pursuant to the direction.

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. This was the approach adopted on 9 February 2017 in South Australia. Following a direction to Pelican Point, AEMO applied a counteraction by issuing instructions to the Mintaro gas turbine and to two of the three Dry Creek units to reduce their output.

148 Clause 3.8.21(a1) of the NER.

149 Recent intervention events in South Australia have lasted three weeks: e.g. from 23 April to 14 May 2018.

150 As discussed in section 4.7, this raises an important issue: where a direction responds to a system security issue, the generation mix that underpins the what-if run is unlikely to constitute a plausible counterfactual because it reflects a system that is not secure. Given this, it may not represent a sound basis for determining spot prices.

151 Clause 4.8.9(h)(3) of the NER.

If a counteraction is effective, then the divergence between prices in the what-if run and the dispatch run should be very small because the supply/demand balance underpinning both runs is roughly the same. Indeed, if an effective counteraction can be identified, there seems to be no economic rationale for applying intervention pricing: the act of counteracting has already removed the distortionary effect of the direction, so there is no need to implement intervention pricing.

If no counteraction is imposed, and other factors hold constant, the amount of energy exported from the region where the direction was issued 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.

When an intervention event brings on additional capacity and counteractions are not implemented, the prices produced by the what-if run will generally be higher than those produced by the dispatch 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 dispatch run will generally be lower due to the addition of generation capacity. This is not to say that the spot price is being pushed up by the intervention. 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 4.1 which shows that the commencement of a direction issued in September 2017 did not result in spot prices rising. However, the use of intervention pricing means that the spot price in the what-if run does not fall (as it does in the dispatch run - shown in red) in response to additional generating capacity coming online. This divergence between the what-if run and the dispatch run occurs when counteractions are not put in place to reduce the effect of the direction on the supply demand balance.

Figure 4.1: Impact of direction on SA prices 22-25 September 2017

Source: AEMC analysis

4.5 Counteractions in South Australia

Counteractions in connection with system strength directions have only been used on a limited number of occasions: specifically, when synchronous generators are operating above their minimum safe operating level and are thus able to be constrained down when another generator is directed on to ensure adequate system strength. For example, during an intervention event on 23-26 February 2018, AEMO directed Osborne power station to remain synchronised and follow dispatch targets (rather than de-commit as it had planned to do). In compliance with clause 3.8.1(b)(11), AEMO then applied counteraction constraints to reduce the output from Pelican Point power station and a number of units at Torrens Island power station.[152] Similar counteractions on Torrens Island and Pelican Point were also applied on other occasions e.g. 4-6 November 2017, 29 January 2018 and 4 February 2018.

In other cases, when synchronous generators are offline or operating at or close to their minimum safe operating level, the generators on which AEMO could apply a counteraction would be wind farms. However, AEMO advises that there are practical difficulties with counteracting on wind farms:

- Counteractions must be implemented manually, and because of the intermittent output of wind farms it is difficult to manage a manual counteraction, particularly when the direction may span multiple days.

152 AEMO, *NEM Event – Direction 23-26 February 2018,* ¸June 2018, p. 6.

- Further, AEMO's current systems do not support automatic invocation of counteraction constraints.[153]

4.5.1 Effectiveness of counteractions

The 9 February 2017 counteraction discussed in section 4.4 did not have the intended effect of confining the impact of the intervention to South Australia. As noted in a report commissioned by AEMO into the intervention event and the anomalous pricing outcomes that followed:[154]

> Superficially the counter-action should have restored the demand and supply balance in South Australia and so have minimal impact on the other regions. However, when compared with the dispatch run of NEMDE, the intervention pricing run yielded different interconnector flows, generator outputs and spot prices in other regions, most notably New South Wales and Queensland.

The same report identifies the necessary conditions for a counteraction to be effective, and states that only in some cases is a reasonable counteraction available.

AEMO has since identified that, on 9 February 2017, a feedback constraint in NEMDE bound incorrectly, which led to less power flowing north from Victoria to NSW and Queensland and therefore caused more expensive generators to come online.[155] This led to much higher than expected prices in the 'what-if' run of the dispatch engine.[156] The counteraction does therefore not appear to be the cause of the unusual price outcomes arising from the intervention.

Counteractions can nevertheless be challenging to implement. As we understand it, it is not currently possible for AEMO to:

- predict what the precise effect of a counteraction will be prior to issuing it; or
- identify the actions (i.e. instructions to generators) that will form the optimal counter-action.

This is because there are many thousands of constraint equations that are included in NEMDE. A portion of these constraints may contain terms that represent the output of units that are directed, or selected for counteraction. Predicting how a given counteraction will affect the dispatch solution in real time is therefore challenging.

4.5.2 What happens when counteractions are not applied?

When counteraction is not applied, the direction can have an effect not only on outcomes in the region of the direction, but also in other regions.

153 See slides and minutes from meeting 4 of the Intervention Pricing Working Group - available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group

154 Endgame Economics and SW Advisory, *Review of Intervention Pricing*, October 2017, p. 33

155 AEMO Intervention Pricing Working Group, meeting 2 – 20 December 2017.

156 The Intervention Pricing Methodology has since been amended to rectify the issue that caused this result.

Consider for example the effect of directing on a unit in South Australia in response to inadequate system strength without any counteraction. While the direction is for system security rather than reliability, requiring the generator to synchronise and operate at minimum safe operating level will result in additional energy being supplied to the market. Holding all other factors constant, the additional output of the unit will increase supply in South Australia, and so alter the flow across the interconnectors to Victoria. This will either lessen the amount of imports into South Australia, or increase exports from the region.

Either way, the neighbouring region of Victoria – and potentially New South Wales, Tasmania and even Queensland – will have a decreased demand for its generation. As a result, not counteracting may mean that a direction in one region can potentially affect outcomes in all other regions.

The table below illustrates the effect on dispatch outcomes of a system strength direction issued in May 2018 in South Australia. No counteraction was implemented in connection with the directions and, as a result, generation output declined in NSW and Victoria.

Figure 4.2: Impact of SA direction on interconnector flows, dispatch outcomes

Table 3 Estimated changes to local generation in each region (MWh)

	QLD	NSW	VIC	SA	TAS
Without direction	608,086	628,030	461,873	122,411	111,574
Actual	608,271	624,937	460,403	122,508 + 4,760[A]	111,574
Change	+185	-3,093	-1,471	+4,857	0

A. 4,760 MWh is the directed energy.

Table 4 Estimated changes to interconnector flow between regions (MWh)

	Terranora	QNI	VIC-NSW	Heywood	Murraylink	Basslink
Without direction[A]	-7,388	-54,464	36,426	-10,451	-3,328	0
Actual[A]	-7,376	-54,647	39,507	-14,173	-4,355	0
Change[B]	12 MWh less into NSW	183 MWh more into NSW	3,081 MWh more into NSW	3,722 MWh more into VIC	1,027 MWh more into VIC	0

A. Positive numbers are for flows flowing north or west, negative for flows flowing south or east.
B. Change = |Actual - Without direction|.

Source: AEMO, *NEM Event - Direction 23-29 May 2018*, September 2018, p. 7

AEMO's South Australian Electricity Report notes "generation in South Australia increased 27 per cent in 2017-18, about half supplied from gas-powered generation (GPG). The extra generation was used to meet local demand and exported to Victoria, with 2017-18 being the first time in at least nine years that South Australia was a net exporter of energy."[157] In addition to the effect of new wind capacity, this is attributable in large part to the high number of system strength directions issued to gas fired generators in South Australia and

157 AEMO, *South Australian Electricity Report,* November 2018, p. 4

AEMO's practice of not counteracting on wind generators in order to confine the impact of the direction to South Australia.

4.5.3 Issues associated with counteractions

A number of questions arise regarding the use of counteractions, including in relation to how they interact with intervention pricing. Given that the purpose of the counteraction is to balance out the effect of the original direction, it should follow that intervention pricing is not necessary because the supply demand balance underpinning both the what-if run and the dispatch run should be the same (or similar). However, the Rules do not currently achieve this objective – intervention pricing is still implemented in the case of counteraction, reflecting that counteractions may not precisely offset the impact of the direction.

When system strength directions bring online additional gas fired generation in South Australia and counteractions are not imposed, more energy - including a considerable volume of wind energy - is exported to other regions. As a result, higher cost generators in those other regions generate less. This means the fuel costs that would otherwise be incurred by those generators are avoided. This may represent a more efficient outcome than - for example - constraining down wind in South Australia (assuming AEMO were to develop the capability to counteract on wind farms) in order to allow more costly generators in neighbouring regions to run as normal.

There is thus a question, from both an efficiency and equity perspective, as to whether it is preferable to manually adjust the dispatch process through the application of a counteraction, or whether it is preferable to let NEMDE optimise the dispatch targets that naturally follow once a direction has been issued. It may be, for example, that it is more efficient to let NEMDE automatically constrain down a unit or units in a neighbouring region if they have higher costs than the unit/s which are available to be constrained down in the region in which the direction was issued.

In considering whether this would deliver greater efficiency and reduce compensation costs to South Australian consumers, it will be important to consider the impact on interconnector flows and holders of SRD units[158]. This is because SRD unit holders are eligible for affected participant compensation when a direction impacts interconnector flows.

Under clause 3.12.2(2)(c) of the NER, AEMO is required to notify 'eligible persons' (viz. SRD unit holders) of the estimated level of flow in MW of all relevant directional interconnectors that would have occurred had the AEMO intervention event not occurred, and an amount equal to the estimated amount that person would have been entitled to receive pursuant to clause 3.18.1(b) had the intervention not occurred (less the actual amount received).

The impact on interconnector flows and eligible persons is a factor to consider in determining the difference in efficiency and compensation costs as between two possible approaches:

158 SRD is shorthand for settlements residue distribution agreements. A SRD unit is defined in chapter 10 of the NER as 'a unit that represents a right for an eligible person to receive a portion of the net settlements residue under clause 3.6.5 allocated to a directional interconnector for the period specified in a SRD agreement entered into between that eligible person and AEMO in respect of that right'. These units are auctioned off by AEMO as part of the process of managing inter regional settlement residues.

- counteracting in the directed region (the region in which the direction was issued) in order to limit interconnector flow impacts, and
- not implementing counteractions and instead allowing NEMDE to optimise dispatch targets across the NEM at least cost when additional generation is brought online pursuant to a direction

The optimal approach will involve striking an efficient and equitable balance between the interests of SRD unit holders (some of whom use SRD units to manage their risk in the market) and South Australian consumers, who bear the cost of compensating affected participants, including SRD unit holders.

This in turn raises another question regarding the benefits that could flow to other regions if intervention pricing was not applied in connection with system strength directions. If this were the case, and spot prices in other regions were allowed to fall as a result of changes to dispatch targets in those regions[159], then the benefit of the direction would flow not only to consumers in South Australia (who enjoy the benefit of a secure system) but also to consumers in other regions where changes to the generation mix (displacement of more costly generators) would result in lower wholesale energy prices.

If this outcome were realised, then the cost of the directions could be shared across a larger number of consumers. At present, and in accordance with what is known as the 'regional benefit test', consumers in South Australia bear the entire cost of the system strength directions.[160] However, if intervention pricing was removed (and assuming counteractions are not applied), these benefits would flow to other regions and thus the compensation costs associated with the directions could also be spread more widely, thus reducing costs to South Australian consumers.

QUESTION 5: COUNTERACTIONS

1. Are the results of counteraction too difficult to predict?
2. Should the NER continue to require AEMO to use counteractions in connection with AEMO intervention events, or is it preferable to allow NEMDE to optimise dispatch at least cost?
3. If counteractions remain, should AEMO still implement intervention pricing when it counteracts a direction?

There are also questions regarding the interaction between counteractions and affected participant compensation. These are discussed further in Chapter 6.

4.6 AEMO's review of 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

159 This assumes little or no counteraction is in place.

160 Clause 3.15.8(b1)

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.[161] The prices produced by the two runs (dispatch run and what-if run) on that occasion were materially different.[162]

This was because a feedback constraint in NEMDE bound incorrectly in the what-if run – 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 dispatch run or real world).[163] A similar incident occurred on 13 January 2018 when binding feedback constraint equations limited interconnector flows in the what-if run, resulting in higher prices.[164] AEMO has since consulted on and made changes to the Intervention Pricing Methodology to address these issues.

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.[165] It also established the Intervention Pricing Working Group (IPWG) 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."[166]

In reviewing recent intervention events, the consultants note that:[167]

> 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.

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)

161 SW Advisory & Endgame Economics, op cit, p. 19.

162 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.

163 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 previous dispatch interval of the pricing run) in the NEMDE algorithm used for intervention pricing purposes.

164 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

165 SW Advisory & Endgame Economics, op cit

166 Ibid, p. 5.

167 Ibid, pp. 9-10.

does not apply when there is no relevant market and that AEMO should not use intervention pricing in such cases.[168]

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).[169] 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 inherently introduced during the exercise".[170] 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.[171]

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.[172] 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.[173]

A similar approach was also recommended in submissions to the *Reliability Frameworks Review* interim report with respect to the RERT. EnerNOC's submission stated that "one option the Commission could explore further is to set the spot price to the Market Price Cap for the duration of Strategic Reserves activation. This would preserve investment price signals with absolute undeniable certainty, and also put AEMO under pressure only to intervene as late as possible, and only when involuntary load shedding would otherwise be almost certainly unavoidable." This was echoed in the Energy Efficiency Council's submission.[174]

This proposal contrasts with the current situation whereby intervention pricing is applied whenever the RERT is activated.[175] Under the current approach, the spot price does not automatically rise to the market price cap when the RERT is activated - this will only happen if the what-if run of NEMDE yields the market price cap. As a result, it is possible for prices to remain at relatively low levels (say approximately $300 per MWh), despite AEMO having intervened to activate out-of-market generation and demand response.

For example, consider figure 4.3 which shows the two prices for the duration of the RERT activation on 19 January 2018.

168 Ibid, pp. 28-29.

169 Ibid, p. 49.

170 Ibid, p. 54.

171 Ibid, p. 54.

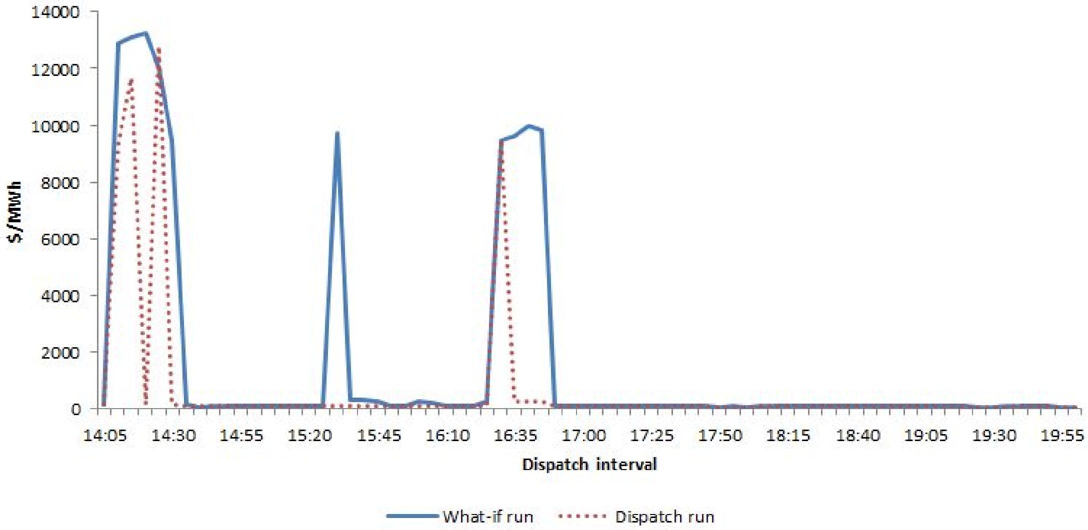
172 Clause 3.9.2(e)(1) of the Rules explicitly states that if there is regional load shedding then 'AEMO must set the *dispatch price* at that *region's regional reference node* to equal the *market price cap*'.

173 Ibid, p. 50.

174 See EnerNOC, submission to interim report, p. 7 and Energy Efficiency Council, submission to interim report, p. 18.

175 As discussed in Chapter 5, however, AEMO proposes that intervention pricing not be applied when the RERT is used to address a localised issue.

Figure 4.3: Intervention pricing during RERT activation 19 January 2018



Source: AEMC analysis

The intervention price was not consistently high during the entirety of the event due to a number of factors, including minimum running times for RERT and projected shortfalls only being forecast in some, but not all, dispatch intervals.

The option of replacing intervention pricing with an approach whereby the spot price is set to the market price cap when the RERT is activated raises significant questions. On the one hand, this would be a simple solution that would alleviate the need to try to simulate what would have occurred in the market had the intervention not happened. On the other hand, it may also be problematic for the following reasons:

- If the price had been at the MPC for the six hours during which the RERT was activated on 19 January 2018, the cost implications for consumers would have been significant.
- If prices are at the MPC for extended periods (more than 7.5 hours), the cumulative price threshold[176] would be passed, triggering an administered price period with flow on effects on prices for the rest of the week.[177] That is, prices would not be able to rise to the MPC on subsequent days regardless of the supply and demand conditions in the market. This would have the effect of muting the very scarcity price signals that the measure is designed to preserve.
- It is unclear what the impact would be in terms of bidding or demand response behaviour.

An additional challenge is that activating the RERT may require 'pre-activation' of reserves to occur in advance of when the shortfall is projected to arise. If the RERT activation then proved unnecessary (for example, because demand was not in fact as high as forecast), the

176 This caps the total market price that can occur over seven consecutive days.

177 During an administered price period, the spot price is capped at $300/MWh.

proposed approach would nevertheless yield prices at the MPC. Further, once activated, reserve contracts may stipulate minimum run times, meaning that the duration of the intervention event may be longer than is in fact required. If the MPC approach outlined above were to be adopted, this could result in the MPC applying for longer than is strictly necessary or efficient.

In addition, the MPC approach may reduce transparency relative to the current situation where intervention pricing is applied when the RERT is activated. This is because there would be no need to undertake both the dispatch run and what-if run in order to set prices, and thus no means to consider what the price would have been had the RERT not been activated. This reduces visibility as to whether the RERT activation was in fact required.

Finally, it is important to consider how prices should be set if the RERT is used in response to a system security issue. While the RERT cannot be procured in response to a system security issue, it can - if it has already been procured in response to a projected reliability shortfall - be used where practicable to address a system security issue. In such cases, setting the spot price to the MPC would not be appropriate.

4.6.1 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.[178]

A number of issues and proposed rule changes were identified.[179] While some proposed changes are administrative in nature (and are being progressed independently of this investigation), two have important implications and are therefore being progressed as part of this consultation paper. For example, it is proposed that the RRN test be extended to apply to the RERT, as well as directions. This proposal is explored in the next chapter.

Another proposed change is 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,[180] the proposed change could lead to increased compensation payments. Given that compensation costs are funded by consumers, this has implications for the NEO. This proposal is discussed further in Chapter 6, along with other issues pertaining to the compensation framework.

More fundamental changes to the intervention pricing framework were not supported by the IPWG. For example, the IPWG did not support the recommendation by SW Advisory and

178 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

179 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.

180 As noted earlier, one intervention in South Australia lasted three weeks: from 23 April to 14 May 2018.

Endgame Economics that intervention pricing only be used when there is relevant scarcity (i.e. of energy or market ancillary services). The IPWG minutes suggest that the following factors informed the IPWG's view that intervention pricing should continue to be used in connection with system strength directions, even where there is no relevant scarcity.[181]

One participant expressed agreement with the consultant's recommendation that intervention pricing should only be implemented in relation to directions for energy/FCAS scarcity. However, the member considered that "the implications of the recommendations are incorrect. If AEMO could procure system strength services which does not involve provision of energy, then intervention pricing does not need to be implemented. However, if the direction involves provision of energy, intervention pricing needs to be implemented…. Where AEMO undertakes an action that injects extra energy into the market outside of the standard energy market process and this has an effect of changing the energy price at the RRN, then intervention pricing should apply. Others agreed with [this] comment" (pp 3-5).

AEMO staff queried whether the purpose of intervention pricing is only for investment signals or whether it should also reflect operational signals. One IPWG member responded "the market price cap is more an investment signal whereas intervention prices are more about effective dispatch. In theory, if we are only relying on the energy-only market to deliver other services such as energy, security and the new services such as system strength, then it is important that we preserve those price signals so as to avoid distortion to the energy market" (p. 6).[182]

The point being made here may be that, if intervention pricing was not applied and the spot price was allowed to fall in response to additional generation coming online pursuant to a system strength direction, generators with fuel costs may withdraw from the market on the basis that the spot price is not high enough to cover their short run costs. AEMO would then need to issue further directions to keep the required combination of synchronous generators online so as to maintain system strength. The vexing corollary of this operational timescale focus is that the longer term investment signals that flow from the intervention price may encourage additional capacity to enter the market and this could worsen the system strength problem (a point recognised by AEMO staff, as noted below).

Another member disagreed with the consultant's view that there is no economic rationale for intervention pricing during system strength events. "The rationale is not to distort the market prices but also not to disadvantage participants in a particular region. If an AEMO direction causes every other generator in the region to pay to generate this is not an optimal outcome." (p. 6)

AEMO staff did note that higher what-if prices signal a need for more generation and this could result in more wind generation which could worsen the system strength situation (p.

181 See minutes of the first IPWG meeting, 20 November 2017, available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group. Page number references in this section relate to these minutes.

182 The minimum system strength framework discussed in chapter 7 has been designed so that, once a system strength shortfall has been declared, it is not necessary to rely on the energy-only market to deliver system strength. Instead, where AEMO has declared a shortfall, it will notify the relevant TNSP to procure system strength services to address the shortfall - for example, by contracting with generators, or procuring synchronous condensers.

5). However, the Minutes conclude that "there was a broad consensus that the way intervention pricing is being applied is leading to the outcomes that was intended in the rules and sending the right economic signals, both in investment and dispatch timeframes" (p. 7).

This discussion took place at the first IPWG meeting, held on 20 November 2017. At that time, there had only been 8 intervention events designed to address inadequate system strength (affecting prices on only 21 days).

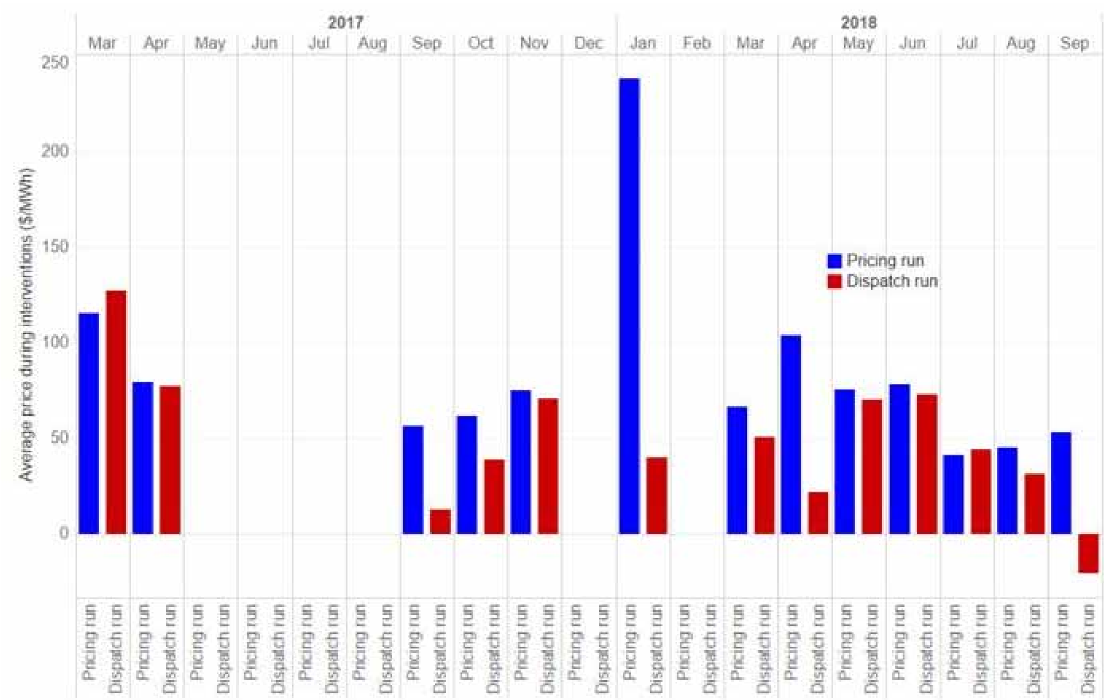
While the NEMDE algorithm issue which caused the anomalous price outcomes on 9 February 2017 and 13 January 2018 has been identified and addressed by AEMO, broader questions remain regarding the economic rationale for applying an intervention pricing approach designed with reliability events in mind to situations centred on security concerns and services that are not traded in the market. Further consideration is warranted as to whether the current "one size fits all" intervention pricing approach is sufficiently nuanced. This is discussed further below and in Chapter 5.

4.7 Impact of intervention pricing on prices across the NEM

The graph below compares dispatch and pricing run prices during interventions in South Australia from March 2017-September 2018. As can be seen, in all months save March 2017 and July 2018, the prices in the pricing run are on average higher than those in the dispatch run.[183] This should not be read as saying that intervention pricing pushed up the spot price compared to what it was prior to the direction. Rather, intervention pricing did not allow the spot price to fall in response to additional generation being brought on line due to the direction. This explains why, as shown in table 4.1 below, prices in South Australia (averaged over calendar year 2018) were more than 10 per cent higher than the average prices produced when dispatch run prices are taken into account.

183 It may be that average dispatch prices in March 2017 and July 2018 were higher than average intervention pricing run prices due to the noise introduced by the rerun approach. This outcome was also seen during an intervention on 25-26 April 2017: see Endgame Economics and SW Advisory, op cit, p. 26.

Figure 4.4: Impact of intervention pricing on spot price in SA



Source: AEMC analysis

Table 4.1 below illustrates the effect of the South Australian interventions on spot prices in South Australia and other regions. The top row shows the average price for the 2018 calendar year using the intervention pricing run of NEMDE which sets the spot price during interventions; the bottom row shows the average price using the dispatch run of NEMDE during interventions. (That is, the amounts shown below account for the fact that intervention pricing occurred in around one third of dispatch intervals in 2018. Taking into account only those intervals when intervention pricing was implemented, the differences between the figures would be substantially greater.) The difference between these two rows gives an indication of the degree to which interventions in South Australia may have affected spot price outcomes in South Australia and other regions.

Table 4.1: Impact of SA directions on spot prices across NEM ($/MWh)

	NSW	QLD	SA	VIC
Average 2018 price using intervention pricing run for interventions	82.1	74.5	100.1	90.0
Average 2018 price using dispatch run for interventions	81.6	73.8	90.1	88.1

Source: AEMC analysis (as at 6 December 2018)

As can be seen, the impact on prices is most marked in South Australia. However, even small differences in prices can have significant effects when the volume of energy traded in larger regions is considered. Table 4.2 shows a comparison of total payments through the pool in 2018 using the what-if prices and the dispatch run prices for interventions. As can be seen, the effect of interventions is not confined to one region: prices in other regions have also been affected. The difference in total payments through the pool due to interventions was $267.1 million in 2018.

Table 4.2: Total payments through the pool in 2018 under dispatch v. intervention pricing run outcomes ($ million)

	NSW	QLD	SA	VIC	TOTAL
Total payments through pool using intervention pricing run for interventions	$5,545.0	$3,901.2	$1,201.0	$3,938.6	**$14,585.9**
Total payments through pool using dispatch run for interventions	$5,508.3	$3,862.3	$1,102.8	$3,845.4	**$14,318.8**
Difference	**$36.7**	**$38.9**	**$98.2**	**$93.3**	**$267.1**

Source: AEMC analysis (as at 6 December 2018)

There are several points to note in relation to this data. First, the effect of the January 2018 RERT activation contributed $103 million to the total of $267 million. Leaving aside this amount, the total wholesale energy price impact of intervention pricing arising from system strength directions issued in South Australia was $164 million across the NEM in 2018 (as at 6 December 2018). Similarly, when the effect of the RERT activation is excluded, the impact of intervention pricing on spot prices in South Australia in 2018 is $70.6m rather than $98.2m. This is the impact on South Australian spot prices associated only with system strength directions.

Secondly, this estimate of the impact of intervention pricing represents an upper limit of the impact. This is because the market could be expected to self-correct at least to some degree if intervention pricing was not applied and prices were allowed to fall in response to additional generation coming online in response to a system strength direction. For example, in South Australia, removing intervention pricing and allowing the spot price to fall to reflect the supply demand balance that follows from the direction could be expected to prompt generators to rebid or withdraw from the market rather than pay to generate when prices fall to strongly negative levels.

Thirdly, higher spot prices typically do not translate immediately or directly into higher prices for consumers. This is because most retailers have hedge contracts with generators in order to manage wholesale price volatility. However, contract prices are negotiated having regard for expectations about future spot prices. Given that the ElectraNet synchronous condensers will not be in place until mid to late 2020, it is reasonable to expect that directions will continue to be issued in the interim. If intervention pricing continues to apply as it has done to date, then high spot prices in South Australia will put upward pressure on contract prices and thus wholesale energy costs (which account for around 46 per cent of a typical electricity bill in South Australia).

It is also worth considering who receives the higher spot prices that flow from the application of intervention pricing. The chief recipients of higher spot prices during system strength directions will be wind generators (who do not provide system strength), together with any gas fired generators who are operating without being directed to do so. Gas fired generators who are operating pursuant to a system strength direction do not receive the spot price. Instead, they are compensated based on the 90th percentile price. This highlights the issue of what signals are being sent both to generators in operational timescales, and to potential investors.

Finally, it should be noted that implementation of the minimum system strength framework would significantly reduce if not remove the need for AEMO to issue directions to generators to maintain system strength.[184] As such, it would significantly mitigate or remove the wider impacts on wholesale prices outlined above that result from the use of directions and intervention pricing. This could occur in one of two ways. First, if ElectraNet (or the relevant TNSP in a region other than South Australia) were to contract with generators to supply system strength services, those generators would be constrained on by AEMO when required to support system strength (rather than being directed to operate by AEMO).

Such system strength generating units are not eligible to set the spot price when they are dispatched at their minimum loading level (or minimum safe operating level). However they are eligible to receive the spot price, in addition to contractual payments from the TNSP.[185] When such units are constrained on, it is reasonable to expect that the spot price would be similar to the dispatch run prices shown in table 4.1 above, reflecting that there is plenty of energy available at such times but (without the constrained on generators) inadequate fault current. No intervention pricing would apply and no directions-related compensation payments would be owing.

Alternatively, if the TNSP opts to install synchronous condensers (as are currently being procured by ElectraNet), the spot price can be expected to fall when wind output is high and demand is low to moderate as AEMO will no longer need to issue system strength directions

184 ElectraNet notes that, even with generator contracts in place, there remains the potential need for AEMO to issue directions once the volumes and unit combinations offered by tenderers have been exhausted: ElectraNet, *South Australian Transmission Annual Planning Report*, June 2018, p. 87.

185 Clause 3.9.7(c) and 5.20C.4(b) of the NER.

and implement intervention pricing in connection with those directions. Again, removing (or significantly reducing) the need to direct gas fired generators will mitigate or remove the cost of directions-related compensation and the wider impact of intervention pricing on wholesale energy prices. The cost of the generator contracts and/or synchronous condensers will be passed through to consumers via TNSP charges, not the spot price. This is discussed further in Chapter 7.

4.8 Is intervention pricing appropriate for system strength directions?

Given the increasing use of directions to maintain adequate system strength in South Australia (SA), intervention pricing has been implemented for around one third of hours in 2018.[186] This is in stark contrast to the use of intervention pricing for reliability directions, of which there have been only two since 2010. During those two events, intervention pricing was used for a total of 4 hours and 5 minutes.[187]

The directions issued in South Australia do not respond to a scarcity of energy or FCAS (in which case there would be a clear rationale for implementing intervention pricing). Rather, the SA directions respond to inadequate system strength - a service which, like inertia, is not traded in the market.

As described in AEMO's South Australian Electricity report, they are directions for the provision of fault current not for energy.[188] This raises questions about whether there is an economic rationale for implementing intervention pricing in such cases.

The Commission is concerned that intervention pricing in connection with system strength directions may be producing inaccurate price signals. Informed by these prices, new entrants may invest in additional capacity, regardless of whether those investments support or undermine system strength. This in turn may result in losses in dynamic efficiency. In this way, efforts to reduce directions-related price impacts on existing generators through intervention pricing may be producing inefficient investment signals as well as higher costs to consumers (due to the market clearing at the higher intervention price).

This concern has also been recognised by AEMO which noted in its December 2018 position paper on intervention pricing that:[189]

> There is a broader concern as whether intervention pricing applied in situations where there is no shortage of general generation available (energy or FCAS), distorts price signals seen by potential investors. It is arguable that this goes against what intervention pricing is intended to achieve - that is, avoiding market distortions. However, it is also arguable that the aim of the 2002 code change [discussed in Chapter 5] was to apply what-if pricing as far as possible for any intervention as a consistent arrangement for the use of directions, if they alter market (energy or

186 AEMC analysis

187 AEMO, *NEM Event – Direction to South Australia Generator – 9 February 2017*, July 2017, p. 12 and AEMO, *NEM Event – Direction to South Australia Generator – 1 March 2017*, January 2018, p. 10.

188 AEMO, *South Australian Electricity Report*, 2018, p. 53; emphasis added.

189 AEMO, *Intervention pricing for system security directions - position paper for the NEM*, December 2018, p. 4.

> ancillary service) outcomes.
>
> AEMO considers this to be a policy consideration that is best considered as part of a coordinated review.

The Intervention Pricing Working Group was of the view that, when a direction results in a perturbation of the supply demand balance, it is appropriate to apply intervention pricing to preserve the price of energy (even though there is no scarcity of energy). On the other hand, the view of the consultants was that, if there is no scarcity of a market traded commodity, the use of intervention pricing to preserve signals to the market is not justified.

Indeed, SW Advisory and Endgame Economics considered that the use of intervention pricing in such cases can have the opposite effect to what is intended: it can cause market distortion rather than minimising it, particularly when interventions are in place for a significant proportion of the time. This is because intervention pricing serves to conflate two services - one being generic MW, and one being system strength. By not allowing the spot price to fall when a system strength direction brings additional capacity online, intervention pricing has the effect of holding the price of energy at levels which do not reflect the actual scale and mix of generators providing energy to South Australia.

The consultants' report states:[190]

> In our opinion, there is no economic rationale for altering prices for energy and ancillary service prices during an intervention that occurs to obtain these 'unpriced services'. No amount of modification of the energy price will signal the scarcity of the unpriced services. AEMO should not therefore use intervention pricing in these cases... There is no economic rationale for intervention pricing being applied to energy and FCAS prices - these services were not scarce and so there is no need to confect a price to signal their scarcity.

In the context of the South Australian system strength directions, this raises two issues.

First, the circumstance prompting the need for the direction was a lack of system strength. Preserving a price signal for energy that does not distinguish between generators which help maintain system strength and those which do not means that market prices are not signalling the services that the system actually needs. Instead, the price for energy creates conditions that are favourable for new entrants, regardless of whether or not they improve or worsen the situation with respect to system strength. New entrants investing on the back of such prices may exacerbate the existing system strength problem, leading to inefficient outcomes.

While concern about investment signals would not be warranted if intervention pricing was only used for a small proportion of the time, the use of intervention pricing for around one third of dispatch intervals in 2018 means that the impact on average spot prices is significant - around 10 per cent higher in South Australia in 2018. This distortionary effect is recognised in ElectraNet's February 2019 economic evaluation report which states: "both AEMO and ElectraNet recognise that ongoing use of generator directions beyond the short-term is not a

190 SW Advisory, op cit, pp. 28-29.

sustainable outcome and leads to distortions in the market, significant costs to consumers and operating difficulties".[191]

Rather than seeking to use the energy price to signal the value of multiple services (energy and system strength) in a blunt way, a more nuanced value stack could be created that could efficiently support investments delivering both reliability and security. Continuing to hold up energy prices in order to avoid adverse impacts on investment signals and resultant concerns about reliability should not be expected to deliver the security that the system needs, and may prompt the need for other more costly measures and investments to address resulting system insecurity.[192]

Secondly, it is important to consider that, in the case of system security directions such as those being issued in South Australia, intervention prices are a function of a hypothetical generation mix that would never be allowed to be realised in practice. (As noted previously, the intervention pricing run does not include those generators which are directed to provide services, and any counteractions implemented in connection with the direction.) AEMO would not allow the system to operate in a state that is insecure as a result of inadequate system strength - as evidenced by the fact that AEMO intervenes in the market by issuing directions when system strength is inadequate.[193]

Given this, a question arises as to whether it is appropriate to set prices in connection with system security directions based on a counterfactual that is not plausible. In such cases, the intervention price is abstracted to a point that does not reflect AEMO's key obligation to operate the system in a secure state.

The Commission considers it important to mitigate, where possible, dynamic efficiency losses that could accrue if distorted price signals lead to inefficient investment outcomes. Accordingly, and building on the work of the Intervention Pricing Working Group, the Commission considers it appropriate to consider further whether intervention pricing should continue to be used in connection with system strength directions.

QUESTION 6: ARE FURTHER CHANGES TO INTERVENTION PRICING WARRANTED?

1. Is there merit in making more fundamental changes to intervention pricing? For example, should intervention pricing only apply in circumstances where there is scarcity of a market traded commodity? If not, what is the economic rationale for applying intervention pricing?

191 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 18.

192 To signal the value of system strength beyond minimum levels, it may be appropriate to create a mechanism that can signal the value to the market of providing additional system strength. This is discussed in chapter 7. This could be combined with the price of (generic) MW to more accurately signal the value of, and incentivise, efficient energy investments.

193 The situation would be different in the context of a reliability direction: AEMO may allow the system to fall short of the reliability standard so long as it is not insecure.

2. Should consideration be given to adopting a different approach to pricing when the RERT is activated - for example, setting the spot price to the MPC?
3. Are there other issues relating to intervention pricing that warrant consideration as part of this investigation?

5 THE REGIONAL REFERENCE NODE TEST

This chapter discusses the regional reference node (RRN) test which is used by AEMO to determine whether to apply intervention pricing when it issues a direction.[194] It examines the origins of the test, how it has been applied to date, and the AEMO rule change request seeking to change the test and extend its application to encompass the RERT.

5.1 Introduction

In order to preserve scarcity signals to the market, AEMO implements intervention pricing when it intervenes in the market by activating the Reliability and Emergency Reserve Trader (RERT) or issuing a direction.

Before AEMO implements intervention pricing in connection with a direction, it must form a reasonable opinion as to whether the 'regional reference node test' (RRN test) is met: that is, would a direction issued to plant at the RRN have avoided the need for the actual direction issued?[195] If the answer is no, then intervention pricing should not be applied. For example, if directing a plant at the South Australian RRN in Adelaide would not have avoided the need to issue a direction to address a localised problem in the south-east of South Australia, then intervention pricing should not apply.

5.1.1 What is the RRN test?

Clause 3.9.3(d) of the NER states that:

> *AEMO* must continue to set *dispatch prices* pursuant to clause 3.9.2 and *ancillary service prices* pursuant to clause 3.9.2A if a *direction* given to a *Registered Participant* in respect of *plant* at the *regional reference node* would not in *AEMO's* reasonable opinion have avoided the need for any *direction* which constitutes the *AEMO intervention event* to be issued.

In other words, if directing a plant at the regional reference node would not have removed the need for the intervention, then AEMO does not apply intervention pricing.[196]

AEMO's rule change request (discussed in section 5.6) describes the RRN test as recognising "that the scarcity price signal at the RRN serves no purpose where action at the RRN could not have prevented the direction. Put another way, scarcity price signals are not appropriate where a direction is issued for plant at a specific location on the network to resolve a localised condition".[197]

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194 The RRN test does not apply when the RERT is activated.

195 The regional reference node (RRN) is the location in each region by reference to which marginal loss factors are calculated, and at which spot prices are determined by NEMDE. With the exception of Tasmania, RRNs are located near the capital cities in each region of the NEM. See table 5.1 for more detail.

196 SW Advisory, op cit, p. 6.

197 AEMO, *Electricity Rule Change Proposal - Regional Reference Node Test following activation of the RERT*, November 2018, p. 3. This request was submitted to AEMO on 17 December 2018.

5.1.2 History of the test

As discussed in Chapter 4, the origin of the RRN test lies in changes made to the directions framework as it existed when the NEM commenced operation in 1998. At that time, the National Electricity Code (the predecessor of the NER) included separate frameworks for directions relating to breach of reliability, security and statutory obligations. Intervention pricing was implemented for directions relating to reliability but not in relation to security directions.

A review of directions in 2000 made a number of recommendations, including that:[198]

- the separate arrangements for reliability, security and statutory obligation directions should be consolidated into a single common arrangement, thereby reducing the level of discretion required to be exercised by NEMMCO
- in the event of a direction, market prices should so far as practicable be set on a 'what-if' basis in order to retain the appropriate price signal in the market and provide an incentive for market-based response in the future

The review report further noted that, in applying 'what-if' pricing, a distinction should be drawn between 'regional and local directions'. It stated:[199]

> A regional deficiency may be redressed by a direction to a participant anywhere in the region. Use of a what-if price for the region will therefore signal the region wide deficiency. On the other hand, a localised deficiency can only be redressed locally. As there is no regional deficiency it is inappropriate for the regional market price to indicate a shortfall, in fact the regional what-if price will be broadly the same as the [dispatch run price or] 'outturn' price (that is, the spot price when there is no attempt to offset the effects of the direction). Market clearing prices are however based on a regional model of the market and cannot readily determine the impact of localised directions. Accordingly, what-if prices will not be calculated for localised directions.

The wording of the current RRN test does not clearly articulate or reflect this original policy intent. Instead, its reference to 'plant at the regional reference node' has prompted decisions to be made based on the physical circumstances pertaining to each case, rather than on whether the application of intervention pricing in a given case is consistent with the policy intent underpinning the test.

For example, AEMO notes in its rule change request that "generally, directions to resolve 'local' issues do not require use of intervention pricing. However, where a local issue coincides with the regional reference node, intervention pricing is applied."[200] Thus, in the case of South Australia, intervention pricing is used in connection with system strength directions because the system strength issue can be addressed by directing Torrens Island Power Station, which happens to be located at the RRN. However, if the same issue were to arise in New South Wales or Queensland, the outcome would likely be different because

198 NEMMCO and NECA, *Power system directions in the National Electricity Market*, May 2000.

199 ibid, p. ii

200 AEMO, *Electricity Rule Change Proposal,* op cit, p. 4.

directing plant at the node in NSW (there is only one relatively small cogeneration plant at the RRN in NSW) would not address system strength issues.

Arguably, one of the goals of the 2000 review (namely, reducing the discretion required to be exercised by the system operator) has not been achieved. Rather than exercising discretion in determining whether the direction in question is a reliability or a security direction (as was the case prior to the 2000 review), AEMO now has to exercise discretion as to whether the RRN test is met and intervention pricing should or should not apply. Recent events in Victoria, and earlier events in South Australia, demonstrate that the current test is unclear and can be interpreted in a number of ways, as discussed further below.

5.2 AEMO guidance on the RRN Test

There is limited guidance in AEMO documents as to how to apply the RRN test – that is, how AEMO should form the requisite reasonable opinion that a direction to a plant at the RRN would have avoided the need for any direction which constituted the intervention event.

An AEMO briefing paper dated March 2011 states (emphasis added):[201]

> For some interventions the Rules [clause 3.9.3(d)] provide that intervention pricing is not invoked and normal price setting continues. **These circumstances apply in situations where equivalent intervention in respect of plant located at the regional reference node would not have removed the need for the intervention actually given**. Thus, if a generator is directed to operate its generating plant to address a supply deficiency that is confined to a part of the network that does not include the regional reference node, then intervention pricing is not invoked. This might occur for example if a network constraint was restricting supply to a remote area near the directed generator.

It is not clear what is meant by "a part of the network that does not include the regional reference node". There is only one RRN for each region in the NEM. It is likely that AEMO is referring to instances where a network constraint effectively separates one part of the network in a given region from the rest of that network (and the RRN is located in the latter part). However, the manner in which the RRN test has been applied in practice does not always appear consistent with this approach, given that, in some cases, there is no relevant network constraint effectively separating the RRN from other parts of the network.

5.3 How has the test been applied to date?

To our knowledge, there have only been four occasions when intervention pricing was not applied as a result of the RRN test – on 13 October 2015, 1 December 2016, 28-29 March 2017 and 16-18 November 2018. These occasions are described below.

201 AEMO, *Briefing paper - operation of the intervention price provisions in the National Electricity Market*, March 2011, p. 4

While AEMO is required to apply the RRN test each time it intervenes in the market by issuing a direction, there is limited discussion in its market event reports as to how the test has been applied. There are some exceptions, also discussed below.

5.3.1 Directions to northern Queensland generators on 13 October 2015

Due to failures on the transmission network in northern Queensland, AEMO directed generators in northern Queensland to synchronise and follow dispatch targets. This was necessary in order to restore the system to a secure operating state. The report detailing the event states: 'intervention pricing was not applied, as the need to restore power system security could not be met by directing plant located at the regional reference node in accordance with NER clauses 3.9.3(b) and (d)'.[202]

5.3.2 1 December 2016: directions to multiple parties in SA

The RRN test was discussed in the AEMO report describing directions issued to multiple participants in response to security concerns in South Australia on 1 December 2016. This relatively detailed discussion of the RRN test is included in four market event reports.[203]

AEMO's report relating to the 1 December 2016 event states:[204]

> AEMO issued directions to three participants in South Australia between 0115 hours and 0500 hours. The first direction was issued to Torrens Island A1 generating unit to provide 10 MW of fast raise FCAS under clause 4.8.9 of the NER. The Regional Reference Node (RRN) test was met for this direction, that is, a direction at the RRN would have avoided the need for the direction (NER clause 3.9.3(d)). Intervention pricing was implemented from (and including) the DI ending at 0135 hours until the end of the direction at the DI ending at 0500 hours.
>
> The remaining three directions involved reducing generation at Pelican Point or reducing consumption at Olympic Dam to manage shortage of fast raise and fast lower FCAS respectively. The RRN test was not met for either of these directions, that is, a direction at the RRN would not have avoided the need for the direction. However, since these directions overlapped with the first direction for which the RRN test was met, AEMO applied intervention pricing for all intervals between the DI ending 0135 hours and 0500 hours.

It is not entirely clear from the above discussion why AEMO considered that the RRN test was not met by the remaining directions. For example, was it because of the location of the plants relative to the RRN,[205] or because issuing a direction to reduce generation or consumption to a plant at the RRN would not have been practicable in the particular circumstances of that event? Adopting the approach outlined in the 2011 AEMO Briefing

202 AEMO, *NEM Event – Directions to northern Queensland generators – 13 October 2015,* July 2016, p. 9.

203 Two reports relating to 1 December 2016 (one relating to directions to multiple participants, and one relating to a direction to Mortlake power station), one report relating to 9 February 2017 and one report relating to 1 March 2017.

204 AEMO, *NEM Event - Direction to South Australia Participants - 1 December 2016*, November 2017, pp 10-11.

205 Pelican Point is very close to the RRN but Olympic Dam is not.

Paper, it could be argued that equivalent intervention at a plant located at the RRN *would* have removed the need for the intervention. This is because managing a scarcity of FCAS can be done by reducing generation and/or consumption anywhere in the network (so long as there are no network constraints in place).

If AEMO's view is based on the location of the actual plants, it is not clear how this approach would apply in regions where there is no actual plant located at the RRN. (See section 5.4.) There is also a potential inconsistency in that the directions issued to Pelican Point on 9 February and 1 March 2017 (discussed below in section 5.3.4) were both considered to meet the RRN test (so intervention pricing was considered appropriate), while the above direction to Pelican Point issued on 1 December 2016 was considered not to meet the RRN test (so, all else equal, intervention pricing should not apply).

It is also worth noting that Pelican Point is very close to the South Australia RRN and in fact has a lower marginal loss factor (MLF) than Torrens Island Power Station – see section 5.4.

Importantly, the RRN test asks whether a direction in respect of plant at the RRN would have avoided the need for *any* direction which constitutes the AEMO intervention event to be issued. This suggests that, where an intervention event comprises multiple directions, intervention pricing should not apply if any of the directions that comprise the event do not meet the RRN test. Given that AEMO concluded that the directions to Pelican Point and Olympic Dam did not meet the test, it is arguable (assuming the conclusion regarding those directions was correct) that intervention pricing should not have applied in this instance. Instead, AEMO concluded that the direction to Torrens Island power station met the test and therefore applied intervention pricing.

5.3.3 1 December 2016: direction to Mortlake power station

Due to the loss of the Heywood interconnector, SA became islanded from the rest of the NEM in the early hours of 1 December. During the separation event, a number of directions were issued to participants in SA (as discussed above). Following the event, SA remained at risk of another separation event and a limit was imposed on Heywood interconnector flows. When Mortlake power station in Victoria commenced generating, a number of constraint equations were violated and flow on the interconnector exceeded the limit imposed. AEMO directed Mortlake to desynchronise.

The AEMO report following the event states:[206]

> The RRN test in accordance with clause 3.9.3(d) was not met for this Direction, that is, a direction at the RRN would not have avoided the need for the Direction. The voltage unbalance issues at APD could only be resolved by reducing output from Mortlake PS, hence a Direction at the RRN would not have avoided the need for the Direction. Intervention pricing was not implemented for this Direction since the RRN test was not met.

206 AEMO, *NEM Event – Direction to Mortlake Generating Unit 12 – 1 December 2016,* November 2017, p. 9.

There is no discussion in the report regarding any network constraint between the Victorian RRN and Mortlake Power Station (which would be relevant if applying the approach to the RRN test outlined in AEMO's 2011 Briefing Paper). The situation was simply that the synchronisation of Mortlake Power Station was what caused the problem and hence only a direction to Mortlake could fix the problem. In other words, a direction to a specific plant was required – not a generic or notional plant located at the RRN.

The characteristics of specific plant are also relevant in determining which generators are required to maintain system strength. For example, are the plants synchronous or asynchronous, slow start or fast start? What is their location and how does the plant contribute to fault levels in various parts of the power system? Given this, it could be argued that the approach adopted in relation to the Mortlake direction (when intervention pricing was not implemented) is also appropriate in relation to system strength directions.

In the case of South Australia, however, it happens that directing Torrens Island power station (located at the RRN) can provide the requisite system strength. On this basis, AEMO considers that the RRN test is met and applies intervention pricing in connection with all system strength directions in SA, irrespective of whether or not those directions include a direction issued to Torrens Island power station. Whether this approach would hold in other regions is an important question. Ideally, the test should be capable of delivering consistent pricing outcomes across the NEM in relation to directions for the same issue, rather than producing different results depending on the location of generators relative to the RRN in each region. This is discussed further below.

5.3.4 28-29 March 2017: directions to Mt Stuart power station

The following description of the directions issued by AEMO on 28-29 March 2017 is taken from the SW Advisory and Endgame Economics report commissioned by AEMO.[207]

> On 28 March 2017, tropical cyclone Debbie made landfall between Bowen and Proserpine in Queensland, and continued in a south west direction. This led to a reclassification of the loss of certain transmission lines as a credible contingency, requiring additional capacity to be brought online in northern Queensland so as to maintain the power system in a secure operating state. When the market failed to respond, a direction was issued to Mt Stuart power station to come online.
>
> Intervention pricing was not implemented during the intervention event, because the RRN test was not satisfied, i.e. the same direction, or change in generation, at the regional reference node would not have alleviated the need for the constraint. Put another way, the requirement for generation could only be met by generation on the non-RRN side of the constraint.
>
> This is the first example we have seen of an intervention to obtain generation during a time of scarcity where there was no intervention pricing, in this case because of the RRN test. The RRN test is a clear example of a decision embodied within the market

207 SW Advisory, op cit, pp 23-24.

rules that, in some circumstances, there is no rationale for taking steps to signal the scarcity of generation. Specifically, the RRN test implies that we draw the line at signalling scarcity of energy at an intra-regional level.

This is an important observation – the Rules contemplate that there are times when no steps will be taken to redress the effect of an intervention on market prices.

<u>Intervention was to obtain an unpriced service</u>

This is also an example of an intervention to obtain an unpriced service. In this case, the directed generators would not have been paid through the spot market for the service that they were providing. Even if the contingency had occurred, Clause 3.9.7 of the Rules explicitly states that:

In the event that a network constraint causes a scheduled generating unit to be constrained-on in any dispatch interval, that scheduled generating unit must comply with dispatch instructions from AEMO in accordance with its availability as specified in its dispatch offer but may not be taken into account in the determination of the dispatch price in that dispatch interval.

In other words, had the contingency occurred the constrained-on generators would not have received the market price cap *even if they were preventing load shedding*. There is therefore no signal to the generators to provide the service – it is unpriced in the spot market.

It follows that there is no case here for intervention pricing, of course noting that intervention pricing was not applied because of the RRN test.

If the NEM had a spot market in locational (sub regional) FCAS or Network Support and Control Ancillary Services (NSCAS), this would be a case for intervention pricing. But the NEM does not have spot markets in either of these potential services. Clause 3.11.6 (a) states that:

….. AEMO may dispatch NSCAS to:

(1) maintain power system security and reliability of supply of the transmission network in accordance with the power system security standards and the reliability standard; and

(2) maintain or increase the power transfer capability of that transmission network so as to maximise the present value of net economic benefit to all those who produce, consume or transport electricity in the market, but AEMO may only call for offers to acquire NSCAS to maintain power system security and reliability of supply of the transmission network in accordance with the power system security standards and the reliability standard.

However, Clause 3.11.6 does not specify a spot market in NSCAS. Hence NSCAS is an unpriced service in the spot market.

Of note is that, consistent with the above comments, the service of system strength is an unpriced service in the spot market. As such, it could be argued that the underlying rationale of preserving market scarcity signals is not applicable given that there is no relevant market for system strength.

The AEMO market event report describing the Mt Stuart direction states: "Intervention pricing was not applied, because the need to restore power system security could not be met by directing plant located at the regional reference node in accordance with NER clauses 3.9.3(b) and (d)."[208]

5.3.5 Reliability events on 9 February and 1 March 2017

There is a brief discussion of the RRN test in two reports relating to reliability related directions issued to Pelican Point on 9 February 2017 and 1 March 2017. The February 2017 report states 'the RRN test was met for this Direction, i.e. a direction at the RRN would have avoided the need for the Direction'.[209] Similarly, the March 2017 report states: 'the RRN test was met for this direction, meaning that a direction given in respect of plant at the RRN would have avoided the need for the direction'.[210]

The approach in both of these reliability-related reports is consistent with the existence of a lack of reserve (LOR) condition in SA at the time the directions were issued: this LOR condition could be addressed by plant at the RRN (or anywhere in the region, assuming there were no network constraints) coming online or increasing output. This approach is consistent with the 2011 Briefing Paper's reference to equivalent intervention at the RRN.

Alternatively (although this seems less likely given the wording of the reports), AEMO may have based its decision on the fact that Pelican Point is very close to the SA RRN and in fact has the lowest marginal loss factor (MLF) of any generator in SA.

5.3.6 System strength directions in SA

The 21 market reports published at the time of writing regarding system strength directions in South Australia state that intervention pricing is being applied in connection with the directions. The reports make no reference to the RRN test or how it is applied. Each report simply includes the following text under the heading 'Application of intervention pricing':[211]

> AEMO declares intervention pricing for periods subject to an AEMO intervention event. Under intervention pricing, NER 3.9.3(b) requires that AEMO set the dispatch price and ancillary service prices at the value which AEMO, in its reasonable opinion, considers would have applied had the intervention event not occurred. AEMO determines and publishes these prices in accordance with the Intervention Pricing Methodology.

AEMO's view is that the RRN test is met in connection with the South Australia system strength directions and thus it is appropriate to apply intervention pricing. AEMO's approach

208 AEMO, *NEM Event - Directions to Queensland Generators - 28 and 29 March 2017*, January 2018, p. 8.

209 AEMO, *NEM Event - Direction to South Australia Generator - 9 February 2017*, July 2017, p. 12.

210 AEMO, *NEM Event - Direction to South Australia Generator - 1 March 2017*, January 2018, p. 11.

211 See for example AEMO, *NEM Event - Direction 07-16 April 2018*, July 2018, p. 9.

(generally and as it relates to the South Australian and Victorian contexts) is set out in its rule change request as follows:[212]

> AEMO's practice is to apply the RRN test considering the following practical considerations:
>
> - There is no distinction in the test between 'reliability' or 'security' directions.
> - The RRN test does not require the existence of a real physical unit to be directed and that the test can be applied to a notional unit at the regional reference node.
> - Generally, directions to resolve 'local' issues do not require use of intervention pricing. However, where a local issue coincides with the regional reference node, intervention pricing is applied.
> - System strength directions in South Australia require one of a number of combinations of units to be directed. One of these combinations involved only units at Torrens Island Power Station, which is located at the regional reference node. Thus the test is passed for all combinations and intervention pricing is required.
> - Recent directions in Victoria to address voltage control and reactive power reserves have been given to address a specific local issue at Keilor 500kV Terminal Station. AEMO did not initially apply intervention pricing to these directions, but has subsequently done so on the basis that the provision of reactive power from a unit at the RRN would have resolved the issue. AEMO is currently developing a position paper for broader discussion with the market.
> - The RRN test is only met if all directions that relate to an AEMO intervention event could have been substituted by a direction at the regional reference node.

5.3.7 System security directions issued in Victoria in November 2018

As noted above, AEMO issued directions in Victoria in November 2018 to address issues relating to both voltage control and system strength. The first direction to address voltage control concerns was issued to Newport power station (located close to but not at the RRN) late on 16 November 2018. This was considered a localised issue and intervention pricing was not applied. However, this direction was later extended (on 17 November) to address inadequate system strength. (This is the first time that AEMO has issued a direction in Victoria in response to inadequate system strength.) Intervention pricing was applied in connection with that portion of the direction to Newport.

The next day, 18 November, AEMO again issued a direction in response to voltage control issues. This direction was issued to Mortlake power station (located in western Victoria, far from the RRN) and intervention pricing was not applied.

In a written briefing to industry following these events, AEMO indicated that 'going forward, AEMO intends to apply intervention pricing for system strength directions in Victoria. AEMO is considering its position on the application of the NER intervention pricing provisions for voltage control in Victoria'.

212 AEMO, *Electricity Rule Change Proposal*, op cit, p. 4.

On 24-26 November 2018, directions were again issued in Victoria to address voltage control issues and intervention pricing was applied (in contrast to the initial weekend). Subsequently, AEMO has indicated it intends to apply intervention pricing in relation to both system strength and voltage control issues for the reasons set out below.[213]

> For system strength directions in both South Australia and Victoria, AEMO is satisfied that sufficient synchronous machines at the respective RRNs would remove the need to direct plant in other places in the regions. AEMO will therefore continue to apply intervention pricing for the period of those directions.
>
> For voltage control directions in Victoria, in relation to the recent high voltage issues, AEMO is satisfied that synchronous reactive plant at the Victorian RRN region reference node would avoid the need to direct elsewhere in the region. AEMO will therefore apply intervention pricing for similar directions going forward.
>
> AEMO has not attempted to examine the economic merits of such an approach. These are best dealt with through policy setting for the NEM.

As with the discussion of the RRN test in the AEMO rule change request, the briefings provided to industry allude both to notional and actual plants at the RRN. At a theoretical level, the application of the test is often described as relating to a notional plant. However, in practice, AEMO has regard for the location of the actual plant involved and whether the location of that plant coincides with the RRN.

As flagged in Chapter 4 (section 4.8), the AEMO position paper also notes that:[214]

> There is a broader concern as to whether intervention pricing applied in situations where there is no shortage of general generation available (energy or FCAS), distorts price signals seen by potential investors. It is arguable that this goes against what intervention pricing is intended to achieve - that is, avoiding market distortions. However, it is also arguable that the aim of the 2002 code change was to apply what-if pricing as far as possible for any intervention as a consistent arrangement for the use of directions, if they alter market (energy or ancillary service) outcomes. AEMO considers this to be a policy consideration that is best considered as part of a coordinated review.

5.4 What is a 'plant at the RRN'?

The RRN test refers to "a *direction* given to a *Registered Participant* in respect of *plant* at the *regional reference node".* In its rule change request, AEMO describes the substance of the test in the following terms: "intervention pricing does not apply where, in AEMO's reasonable opinion, the need for a direction issued in respect of a particular plant could not have been avoided by issuing a direction to (hypothetical or real) plant at the RRN".

Plant is defined in the NER as including (among other things) generators and loads:

213 AEMO, *Intervention pricing for system security directions - position paper for the NEM*, December 2018, p. 5.
214 ibid.

(a) In relation to a connection point, includes all equipment involved in generating, utilising or transmitting electrical energy.

(b) In relation to dispatch bids and offers, controllable generating equipment and controllable loads.

(c) In relation to the statement of opportunities prepared by AEMO, individually controllable generating facilities registered or capable of being registered with AEMO.

(d) In relation to the regulatory investment test for transmission, any of the definitions of plant in paragraphs (a) to (c) relevant to the application of the regulatory investment test for transmission to a RIT-T project.

(e) In relation to the regulatory investment test for distribution, any of the definitions of plant in paragraphs (a) to (c) relevant to the application of the regulatory investment test for distribution to a RIT-D project.

(f) In relation to a system strength remediation scheme, includes all equipment involved in the implementation of the scheme.

While the NER do not make clear whether the test relates to a hypothetical or actual plant, it may be reasonable to interpret the RRN test as referring to a hypothetical plant, particularly given that in only some regions is there an actual generating plant located at or near the regional reference node (RRN).

This appears consistent with the 2011 Briefing Paper's reference to "equivalent intervention" and AEMO's view of the test, as set out in section 5.3.5. In particular, AEMO states in its rule change request that the RRN test "does not require the existence of a real physical unit to be directed and that the test can be applied to a notional unit at the regional reference node".[215] This reflects the view of some that the test can be met by a direction issued to a plant which is "located" at the RRN in an electrical sense, if not a geographical sense (i.e. the plant is connected to the same line as the RRN, and there is no constraint between it and the RRN).

The RRNs for each region in the NEM are shown in table 5.1.

Table 5.1: Regional Reference Nodes for each region of the NEM

REGION	RRN
Queensland	South Pine 275kV node
New South Wales	Sydney West 330kV node
Victoria	Thomastown 66kV node
South Australia	Torrens Island PS 66kV node
Tasmania	George Town 220 kV node

215 AEMO, *Electricity Rule Change Proposal*, op cit, p. 4.

Information regarding generators and loads with marginal loss factors (MLFs) at or close to 1 is shown in table 5.2. An MLF of 1 indicates that the plant is located at the RRN and thus incurs no losses.[216] As can be seen, only in two regions (NSW and Victoria) is there a generator with a MLF of 1. Even Torrens Island in SA has a loss factor greater than 1, despite being adjacent to the RRN.

Table 5.2: Generators and loads with marginal loss factors close to 1

REGION	GENERATOR MLF	LOAD MLF
Queensland	Swanbank E GT has a MLF of 1.0009 which is the closest to 1 of all generators	Blackstone load has an MLF of 1.0001 which is the closest to 1
New South Wales	Sithe (Holroyd Generation) has a MLF of 1. This is a 92 MW CCGT plant at Smithfield	Holroyd Load as an MLF of 1
Victoria	Broadmeadows Power Plant (a small landfill gas plant) has a MLF of 1	Thomastown (Jemena) and Thomastown (Ausnet services) load has an MLF of 1
South Australia	Pelican Point Power Station has a MLF of 1.0005 which is the closest to 1 of all SA generators. (Torrens Island Power Station has a MLF of 1.0009)	Torrens Island Power Station load has a MLF of 1
Tasmania	Basslink (George Town) has a MLF of 1 (note that while Basslink is classified as a generator, there is no generation plant at this location)	George Town (Basslink) load has a MLF of 1

Given this, it may be reasonably open to infer that the RRN test is referring to a hypothetical situation where a direction is issued to a registered participant in respect of a notional plant located at the RRN. In addition to AEMO's views noted above, this would appear consistent with the origins of the test, discussed in section 5.1.2.

216 Data in both tables is sourced from https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Loss_Factors_and_Regional_Boundaries/2018/Marginal-Loss-Factors-for-the-2018-19-Financial-Year—-updated-11-July-2018.pdf

5.5 What happens when intervention pricing is not applied?

If intervention pricing is not applied in connection with a direction (as occurred in relation to the directions to Mortlake in December 2016 and Mt Stuart in March 2017), the spot price and ancillary service prices are set as normal by the central dispatch process. Parties who provide services under direction are still compensated at the 90th percentile price but the market clears as normal, not as per the intervention price.

Clause 3.9.1(a)(3A) provides that:

> Generating units, scheduled network services or scheduled loads which operate in accordance with a direction are to be taken into account in the central dispatch process, but the dispatch offer, in the case of a generating unit or scheduled network service, which operates in accordance with a direction, or the dispatch bid, in the case of a scheduled load which operates in accordance with a direction, will not be used in the calculation of the dispatch prices in the relevant dispatch interval.

There is an equivalent provision relating to ancillary services: clause 3.9.1(a)(3C). Thus, the marginal cost of a directed generator does not influence the spot price.

If intervention pricing was not applied in South Australia when system strength directions are issued, then the spot price would fall (as it does in the dispatch run – used when intervention pricing is being applied) because additional supply has been brought into the market. The spot price would not rise to reflect the marginal cost of the more costly thermal generator that has been brought on line in response to the direction, consistent with clause 3.9.1(a)(3A) above.

This is theoretically consistent with another provision of the NER which provides that, when a generator is directed to provide services, it does not receive the trading amount for the intervals during which the direction is in force. Instead, AEMO keeps these trading amounts and the generator is paid the 90th percentile price (based on prices in that region in the preceding 12 months): see clause 3.15.6(b). Thus, the directed generator neither influences nor receives the spot price.

The operation of this provision means that, when the supply demand balance is tight and the spot price is high, a generator is incentivised to participate in the market and earn the spot price (which at such times will be higher than the 90th percentile price at which the directed generator will be compensated). This may help explain why there have been so few directions for reliability (only two since 2010). By contrast, when the spot price is relatively low (as is the case when system strength directions are issued), being directed and compensated at the 90th percentile price becomes financially favourable. This is discussed further in the next chapter.

5.6 AEMO's rule change request

AEMO's rule change request proposes to extend the reach of the RRN test to encompass the RERT in addition to directions and to clarify the wording of the test to remove ambiguity.[217] It notes that the rule change request has been developed in discussion with the Intervention Pricing Working Group (discussed in Chapter 4), members of which supported extending the application of the RRN test to encompass the RERT.[218] It is noted, however, that the proposed amendments to the wording of the RRN test were not presented to or discussed with the IPWG. AEMO notes that the proposal to extend the RRN test to encompass the RERT was also presented to the NEM Wholesale Consultative Forum.

In relation to the RERT, AEMO notes that, currently, intervention pricing is applied whenever the RERT is activated, regardless of whether there is value in a scarcity price signal at the RRN. Reducing the application of intervention pricing in connection with the RERT 'would prevent the application of higher intervention prices for all intervention events where there is no value in a scarcity price signal at the RRN. This has the potential to reduce costs for consumers'.[219] AEMO considers that, in this way, the proposed rule change would mitigate additional market costs that would arise from exercising the RERT under conditions that do not satisfy the RRN test'. Such outcomes are said to directly promote the National Electricity Objective (NEO) by 'maintaining the efficient operation of electricity services for the long term interests of consumers with respect to price and security of supply'.[220]

In relation to the wording of the test, AEMO notes that "the current drafting of the RRN test has proved difficult for AEMO to interpret. AEMO proposes to improve the drafting of the test by removing double negatives and redundant cross references. These changes are not intended to alter the meaning or application of the test."[221] The rule change request includes proposed amendments to clause 3.9.3(d), set out below for ease of reference:[222]

> AEMO must continue to set *dispatch prices* pursuant to clause 3.9.2 and *ancillary service prices* pursuant to clause 3.9.2A if AEMO is satisfied that the need for the AEMO intervention event could not have been met by a direction to provide energy or market ancillary services~~given to a *Registered Participant* in respect of *plant*~~ at the *regional reference node*~~would not in AEMO's reasonable opinion have avoided the need for any *direction* which constitutes the *AEMO intervention event* to be issued~~.

The Commission considers that the proposed amendments to the clause do impact the substance of the test, as discussed below.

217 The rule change request is available at https://www.aemc.gov.au/rule-changes/application-regional-reference-node-test-reliability-and-emergency-reserve-trader

218 AEMC staff attended meetings of the IPWG as an observer.

219 AEMO, *Electricity Rule Change Proposal,* op cit, p. 5.

220 AEMO, *Electricity Rule Change Proposal*, op cit, pp 5-6.

221 AEMO, *Electricity Rule Change Proposal,* op cit, p. 4.

222 ibid, p. 6

5.6.1 NEO assessment

The Commission's assessment of the above rule change request, together with the compensation threshold rule change request discussed in Chapter 6, must consider whether the proposed rule will promote the NEO as set out under section 7 of the National Electricity Law (NEL) as follows:

> 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:
>
> - price, quality, safety, reliability and security of supply of electricity; and
> - the reliability, safety and security of the national electricity system.

Based on a preliminary assessment of the issues raised by the rule change request, the Commission considers that the relevant aspects of the NEO are efficient investment in electricity services and the price of supply of electricity. The issue of investment relates to the RRN test rule change request since the use of intervention pricing has a bearing on investment signals while the price of electricity is relevant to the rule change request as intervention pricing has a bearing on costs passed through to consumers.

5.6.2 Principles

The Commission has set out a number of principles to guide the assessment of the rule change request in addition to the NEO.

1. Consistency with objectives: will the application of the test achieve its intended objective?
2. Clarity, predictability and consistency: is the RRN test easy to apply and are the outcomes predictable and consistent across the NEM?
3. Efficiency and effect on incentives: will the application of the test result in prices and investment signals that are distorted or accurate/efficient?
4. Equity: will the application of the test result in outcomes that are equitable, noting intervention pricing results in higher costs to consumers?

5.6.3 Issues to consider in relation to the rule change request

As discussed in Chapter 4, the Intervention Pricing Working Group was of the view that, when a system strength direction perturbs the energy supply demand balance, it is appropriate to apply intervention pricing to preserve the price of energy that would have prevailed but for the direction. On the other hand, it could be argued (as did the SW Advisory report) that using intervention pricing to prevent the price of energy falling in the wake of a system security direction masks the actual value of energy in a system that has plenty of MW but insufficient fault levels/system strength.

This tension is reflected in the AEMO rule change request which states:[223]

223 AEMO, *Electricity Rule Change Proposal,* op cit, p. 2

AEMO notes the issue highlighted in its recent review of intervention pricing, that the application of the RRN test may not always result in optimal price signal outcomes when interventions are required for system security reasons (unrelated to supply shortfalls). Based on stakeholder feedback, AEMO considers this issue does not have a straightforward solution and is unlikely to meet the requirements for a non-controversial rule. It is therefore not addressed by this rule change request.

The Commission notes that AEMO has not sought to have its rule change request expedited on the basis that it is non-controversial, and that the scope of the rule change request is not limited to simply extending the RRN test to encompass the RERT. Even if it were limited in this way, it would still be important for the Commission to consider whether, before extending its application, the current RRN test is fit for purpose and achieving its objective of preserving scarcity price signals (when appropriate) in order to minimise the market distortion created by intervention events. In any event, AEMO's proposal to change the wording of the RRN test requires that the Commission consider whether the proposed amendments should be incorporated in any revised rule.

The Commission considers that AEMO's proposal to amend the wording of the RRN test does change the current meaning of the test (contrary to AEMO's stated intent not to alter the meaning or application of the test). The Commission also considers that the proposed change introduces a potentially distortionary element which has implications for the concerns discussed in Chapter 4 regarding the impact of intervention pricing on spot prices and investment signals. These issues are discussed below.

Should the RRN test reference a subset of potential directions?

Currently, the RRN test does not specify what kind of direction given to a registered participant in respect of plant at the RRN would have avoided the need for the intervention. By contrast, the AEMO proposal asks whether the need for the intervention event could have been avoided by a 'direction to provide energy or market ancillary services at the regional reference node'.

This wording may be appropriate when considering the example discussed in section 5.3.3 regarding the directions issued to Mt Stuart in far north Queensland. In that case, a direction to provide energy at the RRN would not have avoided the need to direct a generator in far north Queensland (on the other side of a forecast network constraint resulting from the impact of Cyclone Debbie). However, the application of the proposed wording to other situations - particularly directions for system security - is less straight forward. In the case of system strength, for example, would a direction to provide 'energy' at the RRN avoid the need for a direction to provide system strength?

This raises a host of questions about what 'energy' constitutes. Energy is defined in Chapter 10 of the NER as 'active energy and/or reactive energy'. Active energy is in turn defined as 'a measure of electrical energy flow, being the time integral of the product of voltage and the in-phase component of current flow across a connection point, expressed in watthour (Wh)'. Reactive energy is defined as 'a measure, in varhour (varh), of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of current flow across a connection point'.

This definition of energy does not distinguish between energy produced by different types of generators - for example, synchronous, asynchronous, large, small, slow start or fast start. Directing for 'energy' per se (i.e. generic MW) will not necessarily solve for inadequate system strength. Aside from synchronous condensers, what is typically required to address inadequate system strength is a generator or combination of generators which are synchronous, large, and electrically close to the area where fault levels need to be maintained.[224]

While directing for 'energy' in the past may have delivered system security as an inherent by-product of the provision of electricity, this is no longer the case. The rapid evolution of the generation sector means that it may not be appropriate to incorporate in the test a generic term such as 'energy' when the system security services that are required can only be provided by a subset of energy generators.

This is reflected in the AEMO event reports which describe the use of directions to maintain system strength in South Australia. Each of those reports commences with the following statement: "To ensure adequate system strength for secure operation of the South Australia power system, certain combinations of synchronous generating units must be in service at all time."[225]This reflects that generic MW will not suffice to deliver adequate system strength. Indeed, system strength directions are issued when the South Australian system has plenty of energy but not enough system strength.

Adopting the language proposed in the AEMO rule change request could create uncertainty given the broad nature of the term 'energy' and the variety of energy generators in the current NEM (some of which will be able to provide required system security services and others of which will not). The contrast between using a generic term such as 'energy' and the specific nature of the services required in South Australia is evident in the South Australian Electricity Report's reference to South Australian system strength directions being directions for *fault current* rather than directions for *energy*.[226]

Providing services "at the node"

AEMO's rule change request describes the current RRN test as recognising "that the scarcity price signal at the RRN serves no purpose where action at the RRN could not have prevented the direction. Put another way, scarcity price signals are not appropriate where a direction is issued for plant at a specific location on the network to resolve a localised condition".

What constitutes action at the RRN has been a cause of uncertainty in the application of the test.

224 Battery energy storage technologies with certain power conversion systems can produce substantial fault current and could in future play a greater role in maintaining adequate system strength.

225 See for example AEMO, *NEM Event - Direction 27-28 March 2018*, June 2018, p. 4.

226 AEMO, *South Australian Electricity Report*, November 2018, p. 53.

Under the wording proposed by AEMO, uncertainty can be expected to remain as to what the provision of services "at the regional reference node" means. Does this mean services are provided at or close to the node, by either a real or notional plant? Would it suffice if services were provided by an actual plant which is located far from the node but in circumstances where there is no network constraint between the plant and the node (meaning it is electrically if not geographically located "at" the RRN)?

While AEMO states in its rule change request that the RRN test "does not require the existence of a real physical unit to be directed and that the test can be applied to a notional unit at the regional reference node", it nonetheless relies, in the South Australian context, on the fact that one of the acceptable system strength combinations involves directing the Torrens Island power station only (not in concert with other power stations).[227] "Thus the test is passed for all combinations and intervention pricing is required."[228]

Avoiding the need for *any* direction that constitutes the intervention event

AEMO's proposed amendments to the RRN test remove the current reference to the fact that an intervention event may comprise multiple directions and that, if any of these directions do not meet the RRN test, intervention pricing should not be applied. This reference to "any direction" was inserted in the provision in 2008, a change that was designed to make clear that an intervention event could comprise multiple directions - in which case, if any single direction does not meet the RRN test, intervention pricing is not to apply.[229]

While clause 1.7.1(b) of the NER provide that "words importing the singular include the plural and vice versa", the proposed amendment to the test may introduce an element of uncertainty as to how the test should be applied in instances where an intervention event comprises multiple directions and/or RERT activation. This interpretation clause existed at the time the above amendment was made. Despite this, the decision taken in 2008 reflects that there was still seen to be value in clarifying the application of the RRN test in instances involving multiple directions.

Is there an alternative approach that warrants consideration?

As noted earlier, the Commission is concerned that the proposed amendment may create confusion (e.g. is the direction for energy or fault levels?) and the potential for distortionary pricing impacts (by conflating energy with the provision of specific system security services). To avoid the potential for such distortionary effects, and confusion about whether relevant services are provided "at the node", there may be merit in considering an alternative approach to the test.

One possible approach could be to adopt a test that reflects the economic rationale for intervention pricing and ensures that intervention pricing does not apply when, as AEMO

227 Of the 51 generator unit combinations that AEMO has found to deliver adequate system strength in SA, only two combinations involve Torrens Island power station units only. All other combinations involve units from multiple power stations: AEMO, *Transfer Limit Advice - South Australia System Strength,* December 2018.

228 AEMO, *Electricity Rule Change Proposal,* op cit, p. 4.

229 See National Electricity Amendment (NEM Reliability Settings: Information Safety Net and Directions) Rule 2008 No. 6, available at https://www.aemc.gov.au/sites/default/files/content/47a35cb6-8217-4c0d-8759-a06c248458e7/Mark-up-of-Final-Rule-in-version-20-of-the-National-Electricity-Rules.pdf

says, "there is no value in a scarcity price signal at the RRN". For example, the test could ask whether the intervention event is for a service that is traded in the market. In cases where the service is not traded in the market (e.g. system strength, voltage control or NSCAS), intervention pricing would not apply.

Such an approach would ensure that intervention pricing is only applied where there is an economic rationale for it, thereby mitigating the potential for distortionary price signals and higher than necessary costs to consumers. In addition, this alternative approach would be somewhat "future proof" in the sense that, if new markets are created to value particular services (e.g. system strength), then intervention pricing could be applied to as to preserve the price of that service at the level that would have prevailed but for the direction or RERT activation.

A further consideration could be to ask whether the intervention pricing run (required in order to set intervention prices in accordance with the current AEMO intervention pricing methodology) would be allowed to be realised in practice. As discussed in Chapter 4, the Commission notes it is problematic to set the spot price based on a counterfactual reflecting an insecure power system. This suggests that, where the AEMO intervention is in response to the system being insecure (e.g. because of inadequate system strength), intervention pricing may not be appropriate. By contrast, when an intervention is in response to a reliability event (representing a shortage of a market traded commodity), it may be appropriate for the counterfactual underpinning the intervention pricing run to reflect a system that is temporarily unreliable (as distinct from insecure).[230]

Unintended consequences

AEMO's proposed amendment to clause 3.9.3(d) means that, in the case of intervention events involving the RERT, the test is whether the RERT activation could have been avoided by a direction to provide energy or market ancillary services.

In the case of a reliability event necessitating the activation of the RERT, it is reasonably likely that no in-market generators will be available to direct – hence the need to activate out of market reserves via the RERT. In such a case, under the wording proposed by AEMO, it is arguable that the RRN test would not be met and intervention pricing would not apply.

This is not the intention of the proposed rule change request (which is designed to ensure that intervention pricing does not apply when the event relates to a localised issue, but is not designed to change the current application of intervention pricing during "reliability" events).

This issue will require further deliberation in developing the final rule. (The Commission has the ability, where appropriate, to make a more preferable rule which differs from the rule change proposal as submitted. This power enables the Commission to address issues such as this in drafting the final rule.)

How different versions of the RRN test could work in practice

230 The NER countenance that the system may be in an unreliable state from time to time (in accordance with the reliability standard set out in clause 3.9.3C(a) and noting the tension between this standard and clause 4.2.7(a) and (b)). However, the NER require AEMO to operate the power system in a secure operating state to the extent practicable and, following a contingency event, to return the system to a secure operating state as soon as practical and, in any event, within thirty minutes (clause 4.2.6).

Set out below is a table comparing three different versions of the RRN test. The first column shows the results that follow from the application of the RRN test in it current form. The second shows how the test would work if it is drafted in the form proposed by AEMO, while the third shows how an alternative approach could work. This alternative approach focusses on whether the service which was the subject of the intervention event is a commodity traded in the market.

The examples used reflect the intervention events discussed in section 5.3. Ticks are used to indicate that intervention pricing did apply, or would apply, while crosses indicate that intervention pricing did not or would not apply.

Figure 5.1: How a new RRN test might work in practice

Date of event	Nature of intervention	Current RRN test	AEMO proposal	Alt. approach	Notes
13 Oct 2015	Security event – transmission outage in northern Qld	x	x	x	
1 Dec 2016	Security event due to loss of Heywood – directions to multiple parties due to limited FCAS in SA	√ TIPS x Pelican Pt x Olympic Dam	√ TIPS √ Pelican Pt √ Pelican Pt	√ TIPS √ Pelican Pt √ Pelican Pt	As discussed in section 5.3.1, the Commission queries the application of the current RRN test to this event.
1 Dec 2016	Security event following separation (voltage) – direction to Mortlake	x	x	x	
9 Feb 2017	Reliability event – direction to Pelican Point	√	√	√	
1 Mar 2017	Reliability event – direction to Pelican Point	√	√	√	
28-29 Mar 2017	Security event in Nth Qld due to Cyclone Debbie – direction to Mt Stuart	x	x	x	
25-26 April 2017	Inadequate system strength – directions to TIPS and Hallett.	√	√	x	
The same would apply for the ~210 system strength directions issued to date in South Australia.					
22 May 2018	Security event in Qld (voltage) – Mt Stuart	x	x	x	
16 Nov 2018	Security event in Victoria (voltage) – direction to Newport	x	√[1]	x	While AEMO did not implement intervention pricing (IP) in this instance, it was implemented later in November 2018 in response to the same issue.
17 Nov 2018	Security event in Victoria (system strength) – direction to Newport	√	√[1]	x	While IP was not implemented in this instance, AEMO subsequently indicated that it would apply IP if such events were to arise in future.
18 Nov 2018	Security event in Victoria (voltage) – direction to Mortlake	x	√[1]	x	
24 Nov 2018	Security event in Victoria (voltage) – direction to Newport	√	√[1]	x	
30 Nov 2017	RERT activation – reliability event in Vic	N/A[2]	x[2]	√	Under the alternative approach, IP would apply in relation to reliability events (but the approach during other kinds of events would depend on the circumstances).
19 Jan 2018	RERT activation – reliability event in Vic and SA	N/A[2]	x[2]	√	
24-25 Jan 2019	RERT activation – reliability event in Vic and SA	N/A[2]	x[2]	√	

Source: AEMC analysis

Note: [1] It is assumed that AEMO would apply intervention pricing under its proposed wording, consistent with the approach it outlined in its December 2018 position paper on *Intervention pricing for system security directions*. [2] N/A reflects that the RRN test did not apply to the RERT at the time. [3] The Commission's preliminary view is that, under the AEMO proposal, intervention pricing would not apply if no plant are available to be directed.

This table should be considered indicative only and no reliance should be placed on it. A degree of judgement and interpretation is required in predicting how the AEMO proposal and the alternative approach might be applied in practice. For example, the alternative approach requires forming a view as to whether the service which is the subject of an intervention event is one that is traded in the market.

This is not always clear cut, as evidenced by the independent expert reports prepared in the wake of directions issued to participants in South Australia and Victoria following the loss of the Heywood interconnector on 1 December 2016. For example, the June 2017 report (prepared in response to a request from AEMO to determine the fair payment price for a service other than energy or FCAS) took the view that no compensation was payable to directed participants for the service of reducing output (and in one case being turned off). This was because "the NEM does not compensate generators that are constrained off, and there is no clear exception to this principle when the instruction to reduce output or shut down results from a direction rather than in the process of implementing central dispatch".[231]

However, following a further claim for compensation due to loss of revenue, Synergies revised this initial view (in respect of one claimant but not the other). In its later report, Synergies concluded that the directed participant (in responding to a direction to reduce output due to insufficient available FCAS) had provided a relevant service, described as being "a substitute for the provision of market ancillary services by normal means". As such, Synergies concluded that the participant was entitled to be compensated for loss of revenue under clause 3.15.7B. [232]

By contrast, Synergies maintained its view that Mortlake power station was not entitled to compensation as no relevant service was provided when it complied with a direction to desynchronise in order to restore the system to a secure operating state. (This direction was not in response to inadequate FCAS availability but because the synchronisation of Mortlake power station had caused various constraints to violate.)

This illustrates that there can be a range of views as to what constitutes a service in the market, highlighting the need for clarity and predictability in the NER and any supporting procedures or guidance as to how the interventions and compensation framework is intended to operate.

The system strength directions in South Australia provide another example of the confusion that can arise as to what service is being provided pursuant to a direction (and thus which part of the compensation framework is applicable). For system strength directions, AEMO

231 Synergies, *Final report on compensation related to directions that occurred on 1 December 2016*, June 2017, p. 13.

232 Synergies, *Final report on additional compensation claims arising from AEMO directions on 1 December 2016*, August 2017, p. 13.

calculates compensation for directed participants under clause 3.15.7 of the NER, a clause which relates to directions for energy and market ancillary services. Under clause 3.15.7, compensation is calculated based on the 90th percentile price for the preceding 12 months and the cost of compensation payments is recovered from market customers.

By contrast, ElectraNet's recent economic evaluation report refers to system strength directions as being directions other than for energy and ancillary services. The report notes that the cost of compensation for such directions must be recovered from market customers, market generators and market small generation aggregators in proportion to the customer energy, generator energy and small generation aggregator energy respectively.[233]

The Commission surmises that AEMO considers system strength directions to be directions for energy (as opposed to, for example, directions for fault current) because of the wording of clause 3.15.7A(a1). Under this paragraph, a direction is considered a direction for energy if the need for the direction could have been avoided by the central dispatch process (i.e. if there had been a bid for the dispatch of plant relevant to that direction to provide energy services). As with the AEMO proposal to reword the RRN test, this provision refers to energy in a general sense and is not limited to providers of energy that can also provide the required system strength services. (For example, a bid by a suitably located synchronous power station would provide both energy and the required fault current, while an asynchronous wind farm could bid to provide energy but typically would not also be able to provide the required fault current.) Accordingly, this provision warrants further consideration, informed by deliberations regarding how best to express the RRN test.

QUESTION 7: CHANGES TO THE RRN TEST

1. Do stakeholders consider that the RRN test should be extended to encompass the RERT?
2. Do stakeholders consider that the RRN test should be clarified?
3. If so, how is this best achieved?
4. Are changes required to clause 3.15.7A to bring it into line with any changes made to the RRN test?

233 ElectraNet, *Addressing the system strength gap in SA,* February 2019, p. 20.

6 THE COMPENSATION FRAMEWORK

This chapter outlines the compensation framework that is triggered when AEMO intervenes in the market by issuing a direction or activating the RERT, and explores issues such as the payment of compensation to affected participants and the quantum of compensation payable to directed participants. It also discusses a rule change request submitted by AEMO which seeks to amend one element of the compensation framework: namely, the $5,000 per trading interval threshold below which compensation is not payable to affected participants, and below which additional compensation cannot be claimed by directed participants.

6.1 Compensation following intervention events

While intervention pricing is used to set prices in the NEM during an "AEMO intervention event" (encompassing directions and RERT activation but not instructions), 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 also compensates participants affected by the intervention in order to put them in the position that they would have been in but for the direction or RERT activation. Compensation for affected participants is designed to minimise market distortion resulting from the intervention. It may be paid either by AEMO to affected participants, or by affected participants to AEMO. In this sense, "compensation" is a somewhat misleading description; "restitution" may be a more appropriate term for the repayment of revenue by affected participants to AEMO.

Where AEMO issues a direction, compensation is payable to both "directed participants"[234](those parties to whom the direction was issued) and "affected participants"[235] (those parties who are affected by the direction – for example, a generator whose output 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.[236]

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

234 Clauses 3.15.7 to 3.15.7B of the NER.

235 Clause 3.12.2(a)(1) of the NER.

236 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

direction and the market share of each market customer.[237] For example, the cost of compensation related to system strength directions in South Australia is borne by market customers in South Australia on the basis that the benefit of the directions is confined to that region. By contrast, the NER are silent as to who should pay for any compensation to participants affected by the activation of the RERT.[238] These issues are explored below.

6.1.1 Compensation for directed participants

"Directed participants" are eligible to receive compensation so that they can recover their costs.[239] The NER definition of directed participants is broad,encompassing Scheduled Generators, Semi-Scheduled Generators, Market Generators, Market Ancillary Service Providers, Scheduled Network Service Providers or Market Customers.

Where the directed participant has provided energy or market ancillary services, compensation is in the first instance paid automatically. AEMO adjusts the settlement process so that directed participants are paid for the energy or market ancillary 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.[240] 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.[241] However, a $5,000 threshold per trading interval applies to claims for additional compensation.[242]

The entitlement of directed participants to receive compensation was included in the NER following a review of directions by NEMMCO and NECA in 2000. That review concluded that directed participants should receive a "fair payment" that would cover the cost incurred by the participant in complying with the direction while minimising inequitable impacts on other market participants.[243] The review noted the "existence of the incentive to withdraw capacity" and that this "supports the case that directed participants should be given a 'fair payment'".[244]

The report concluded that the quantum of compensation paid to directed participants should not be set so high as to incentivise generators to withdraw capacity in order to be directed, resulting in abnormally high profits.[245] Adopting a principle of setting the payment at a fair price was seen to "offer a degree of comfort to parties concerned about abnormal profits being made out of directions".[246] While the report of the review set out the fair price principle as the basis on which compensation should be calculated, it did not set out the detail of

237 Clause 3.15.8 of the NER.

238 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.

239 Clauses 3.15.7 and 3.15.7A of the NER.

240 Clause 3.15.7(c) of the NER.

241 Clause 3.15.7B of the NER.

242 Clauses 3.15.7B(a4), clause 3.12.2(b) and (i) of the NER.

243 NEMMCO and NECA, *Final Report – Power system directions in the National Electricity Market,* 2000, p. i, p.6.

244 ibid, p. 29.

245 ibid, p. 30.

246 ibid, p. 29.

determining compensation based on the 90th percentile price. This was done through a later Code change process. The same review also concluded that affected participants should be compensated so that their financial position is not affected by the direction (as discussed in the next section).

The Commission understands that the majority 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 90^{th} percentile price. For example, in South Australia, the 90^{th} percentile price in 2018 was $135. By contrast, the short run marginal costs (SRMC) of the generators who are frequently directed to provide system strength services are below this level. 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.[247]

When a market participant is directed to provide services, AEMO retains the trading amount that the participant would have received for the services had the participant voluntarily provided them (meaning that the participant does not receive the intervention price, in cases where intervention pricing has been implemented).[248]

In place of the trading amount, AEMO pays the participant at the 90th percentile rate. This feature of the compensation framework helps explain why reliability directions are so rare (there have only been two since 2010). During a reliability event, the spot price is generally high, reflecting a tight supply demand balance. This means that it will be more attractive for generators to participate voluntarily in the market and earn the spot price if it is higher than the 90th percentile price.

However, when spot prices are relatively low (as often occurs in South Australia when wind output is high and demand low), then it will be more attractive for generators to be directed and paid the 90th percentile price rather than receive the spot price. This has important implications for generator bidding behaviour and is discussed further in section 6.4 below.

Where a participant is directed to provide services other than energy and market ancillary services, the NER provide that compensation should be based on a "fair payment price".[249]

6.1.2 Compensation for affected participants

Affected participants are those parties (being scheduled generators or scheduled network service providers) whose dispatch targets have been affected as a result of an AEMO intervention event. The definition of affected participant in Chapter 10 of the NER also

247 Anecdotal evidence suggests that the process of seeking compensation for additional costs can be time consuming and costly for directed participants.

248 See clause 3.15.6(b) of the NER

249 Clause 3.15.7A of the NER.

includes "eligible persons", being SRD unit holders who are entitled to receive an amount from AEMO where there has been a change in flow of a directional interconnector.[250]

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.[251] For example, if a generator is constrained down by NEMDE (meaning that they generate less in the dispatch run than in the intervention pricing run), they will be paid compensation by AEMO to put them in the position that they would have been in had the intervention event not occurred. That is, they will be paid the difference between the amount they *would have* received based on their dispatch targets in the dispatch run (combined with the price from the intervention pricing run), and the amount they *have received* based on their dispatch targets in the intervention pricing run (again combined with the price from the intervention pricing run). By contrast, if a generator's output following an intervention is higher than it would have been had the intervention not occurred (i.e. it generates more in the dispatch run than in the intervention pricing run), it will be liable to pay an amount back to AEMO.

While such sums can be considerable, no information is publicly available as to the quantum of compensation paid to or by individual affected participants. Only the "compensation recovery amount" is published by AEMO. This is the sum of the

- compensation paid by AEMO to directed participants (net of the trading amounts retained by AEMO in accordance with clause 3.15.6(b) of the NER)
- compensation paid by AEMO to affected participants net of amounts paid by affected participants to AEMO, and
- costs paid by AEMO to independent experts.

The only exception is where an independent expert has been engaged to assess a claim by an affected participant for additional compensation, or where the affected participant disputes the amount it has to pay to AEMO and this is reviewed by an independent expert. A recent example is the review by Synergies Economic Consulting of a dispute by CS Energy of the amount it is required to pay to AEMO.[252]

This followed a system strength direction issued in South Australia on 29 August 2018 and the resultant impact on dispatch targets for Gladstone Power Station in Queensland. AEMO advised CS Energy that it was required to refund an amount of just under $290,000 being the balance of additional revenue that it would not have received, and the additional costs that it would not have incurred, but for the direction. In its determination, Synergies concluded that CS Energy was not liable to repay the amount to AEMO on the basis that the sums in question would not have exceeded the $5,000 threshold per trading interval.

250 SRD is shorthand for settlements residue distribution agreements. A SRD unit is defined in chapter 10 of the NER as 'a unit that represents a right for an eligible person to receive a portion of the net settlements residue under clause 3.6.5 allocated to a directional interconnector for the period specified in a SRD agreement entered into between that eligible person and AEMO in respect of that right'. These units are auctioned off by AEMO as part of the process of managing inter regional settlement residues.

251 Clause 3.12.2(a)(1) of the NER.

252 Synergies Economic Consulting, *Independent Expert Determination on claim for Additional Compensation from Directions on 29 August 2018, Final Report*, January 2019.

As with directed participants, the compensation process for affected participants is automatic: 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).[253] This additional amount is then incorporated into the participant's final statement for the relevant billing period.[254] To estimate these figures, AEMO reruns NEMDE, doing both a dispatch run and an intervention pricing run (even if intervention pricing is not being implemented).

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.[255] 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 (as occurred in the above example involving CS Energy).[256]

While the NER do not make any such distinction, there are in a practical sense two kinds of affected participant: those whose dispatch targets are affected as a direct result of counteraction instructions issued by AEMO, and those whose dispatch targets are indirectly affected as a result of NEMDE optimisation following the intervention event.

There is greater transparency about the first of these groups, and virtually no transparency about the second group (unless an independent expert is engaged to prepare a report, as per the CS Energy example above). NEM Event reports prepared following intervention events identify participants to whom AEMO has issued counteraction instructions. For example, when AEMO directed Pelican Point GT12 into service on 9 February 2017, it issued counteraction instructions to other Pelican Point units, to Mintaro and Dry Creek generating units.[257] However, no information is provided about other generators whose dispatch targets are affected as a result of NEMDE optimisation - despite the fact that payments to and from such generators may be significant.

Affected participants are entitled to receive compensation once a direction has been issued, regardless of whether intervention pricing has been implemented in connection with that direction. Clause 3.12.2(a)(1) of the NER provides that in respect of each *intervention price trading int*erval (a trading interval in which AEMO has declared an *intervention price dispatch interval* under cl 3.9.3) an affected participant is entitled to receive from AEMO/pay to AEMO an amount that would put them in the position they would have been in had the *AEMO intervention event* not occurred. This amount is subject to the $5,000 threshold.

This threshold also applies to directed participants (but only in respect of claims for additional compensation).[258] The rationale for the threshold is that, if the amount is less than $5,000,

253 Clause 3.12.2(c) of the NER.
254 Clause 3.12.2(d) of the NER.
255 Clause 3.12.2(b) and (i) of the NER.
256 Clauses 3.12.2(f) and (g) of the NER.
257 AEMO, *NEM Event - Direction to South Australia Generator - 9 February 2017, July 2017, pp 5-6.*
258 Clause 3.15.7B(a4) of the NER.

this amount is immaterial and does not justify the costs of determining a compensation payment.[259]

6.1.3 Origin of the threshold and application to date

The $5,000 threshold was included in the NER following the 2000 Review of Directions mentioned earlier. The report of the review noted that:[260]

> Payment should only be made where the value at stake is sufficient to justify the significant administrative outlays in determining compensation. We propose that consideration only be given to payment claims with a value exceeding $5,000 to each individual party, with amounts less than this deemed immaterial given the costs of settling claims.

Following this review, the Code Change Panel recommended the inclusion of a provision in the following terms: "a *Directed Participant* may only make a claim pursuant to clauses 3.15.7B(a), 3.15.7B(a1) or 3.15.7B(a2) if the amount of the claim is greater than $5,000." Notwithstanding this recommendation, the provision as adopted includes a reference to trading intervals. It is unclear why this change was made to the provision as adopted.

The history of these provisions is discussed in Synergies' final report on compensation claims relating to directions issued on 1 December 2016. That report also discusses whether there is a tension between the wording of clause 3.15.7B(a) and (a4). The report notes: [261]

> Clause 3.15.7B(a4) is difficult to reconcile with the drafting of 3.15.7B(a). It limits its effect with the opening phrase "In respect of a single intervention price trading interval". If the historical interpretation [applying the $5,000 threshold per trading interval] is adopted it then proceeds to limit Directed Participant claims to cases where the claim amount for each trading interval is more than $5,000. As we noted above, this construction sits at odds with the conception of a claim as a single claim for a single aggregate sum given in 3.15.7B(a) for the entirety of the period to which the relevant direction relates.
>
> Unless a direction affects only a single trading interval, it follows that any resulting claim under 3.15.7B(a) is unlikely to have been made in respect of a single intervention price trading interval. Rather, the claim will be made in respect of the aggregate effect of a direction. Further, the claim will make deductions of lump sum amounts corresponding to the revenue already received pursuant to a compensation determination by AEMO and/or settlement (3.15.7B(a)(3)).
>
> The interpretation of 3.15.7B(a4) that has been accepted up until this point [by previous independent expert reports] relies on treating the Directed Participant's claim as a divisible set of claims relating to individual trading intervals. We consider this inconsistent with 3.15.7B(a).

259 SW Advisory & Endgame Economics, op cit, p. 51

260 NEMMCO and NECA, op cit, p. 30.

261 Synergies, *Final report on additional compensation claims arising from AEMO directions on 1 December 2016,* August 2017, p. 16.

> A further problem with the historical interpretation [applying the threshold per trading interval] is that to be internally consistent, the lump sum deductions provided for by sub-paragraphs 3.15.7B(a)(2) and (3) should also be disaggregated by trading interval to calculate each sub-claim at a trading interval level. It is our understanding that previous expert determinations to which 3.15.7B(a4) applied have applied the lump sum deductions from 3.15.7B(a)(2) and (3) as a separate procedure at the aggregate level, rather than incorporating the trading interval components of these parameters into the assessment required by 3.15.7B(a4).
>
> In summary, we are unable to identify a satisfactory reconciliation of clause 3.15.7B(a4) with clause 3.15.7B(a).

The above tension is evident in the varying manner in which these provisions have been applied by independent experts engaged by AEMO to determine compensation claims. For example, an independent expert report by Harding Katz adopts what is described above as the historical interpretation. That report notes:[262]

> [In response to our draft report], AEMO informally raised a query regarding the interpretation of clause 3.15.7B(a4), which states: "In respect of a single intervention price trading interval, a Directed Participant may only make a claim pursuant to clauses 3.15.7B(a), 3.15.7B(a1) or3.15.7B(a2) if the amount of the claim in respect of that intervention price trading interval is greater than $5,000."
>
> AEMO noted that the $5,000 threshold could be interpreted as relating to the direction, rather than each trading interval (which was Origin's approach and the approach adopted in our draft report). AEMO's alternative interpretation of clause 3.15.7B(a4) is supported by three observations:
>
> 1. The compensation under 3.15.7A (and 3.15.7) relates to a direction, not a trading interval.
>
> 2. To give effect to 3.15.7B(a4), the costs incurred by the directed participant would need to be apportioned to trading intervals. While some costs, such as fuel costs can be attributed to trading intervals, other costs, such as start up or maintenance costs, would need to be apportioned to trading intervals in some (possibly arbitrary) way.
>
> 3. The economic principle is that the directed participant should be fully compensated for the costs of the direction. Applying the $5,000 threshold to each trading interval may in some cases have a material impact on the amount that can be claimed by the directed participant.
>
> While we agree with the issues raised by AEMO, clause 3.15.7B(a4) clearly states that the $5,000 threshold applies to each trading interval. Origin applied this interpretation of clause 3.15.7B(a4) by attributing the fuel costs to each trading interval and apportioning the start up costs to each trading interval on a MWh basis. The clause can therefore be applied as drafted, even if it may raise cost allocation issues in some

262 Harding Katz, *Compensation for directions in Queensland on 28 and 29 March 2017,* September 2017, pp 2-3.

> cases.
>
> In summary, we think there is a case for seeking an amendment to clause 3.15.7B(a4) (and possibly 3.12.2(b)) so that the threshold applies at the direction level. It is less clear what this threshold amount should be, noting that it may be substantially more than $5,000. As drafted, however, our view is that clause 3.15.7B(a4) applies the threshold to trading intervals, which is consistent with Origin's approach in its compensation claim and our draft report.

The above approach (applying the threshold per trading interval) was also adopted by Synergies Economic Consulting in its June 2017 report on compensation claims arising from the directions issued on 1 December 2016. As discussed earlier, however, Synergies adopted a different (per-event) approach to the threshold in its August 2017 report relating to the same directions, and in its September 2017 report relating to directions issued on 25 April 2017.[263]

More recently, Synergies has again adopted a per-trading interval approach to the threshold in determining the claim by CS Energy relating to directions issued in August 2018. In the latter instance, Synergies determined that CS Energy was not required to refund an amount of $283,787 to AEMO on the basis that the amount owing in each trading interval would not exceed the $5,000 threshold. Their final report notes:[264]

> If we assume that CS Energy is an Affected Participant in the formal sense because the direction did result in minor changes in the dispatch level of the Gladstone Power Station, this would not automatically give rise to a need for compensation. Clause 3.12.2(b) limits the payment/recovery of compensation to trading intervals where the adjustment is more than $5,000. If we assume that the average difference between Gladstone Power Station's trading revenue and its SRMC was somewhere in the order of $10/MWh and $50/MWh over the period in question, exceeding the $5,000 threshold would require a difference in output of between 100 and 500MWh in each trading interval, which translates to a difference in dispatch levels of between 200 and 1000MW for the Gladstone Power Station as a whole, or between 40 and 200MW on average for each of the five generating units in question.
>
> Based on the above, Synergies considers that it is reasonable to believe, in the absence of compelling evidence to the contrary, that the $5,000 threshold is unlikely to have been cleared in any of the trading intervals in question. In other words, even if the directions did affect dispatch levels at the Gladstone Power Station, we consider that the magnitude of the true effect was unlikely to have been material by the standards of the Rules (i.e. clause 3.12.2(b)).
>
> This leads us to conclude that the original trading amounts paid to CS Energy in accordance with 3.15.6 (i.e. as part of normal settlement processes) should be allowed

263 Synergies, *Final report on claims for additional compensation arising from directions on 25 April 2017*, September 2017, p. 13.

264 Synergies, *Independent expert determination on claim for additional compensation from directions of 29 August 2018*, January 2019, p. 19.

to stand without any further compensation required.

The approach to the threshold adopted by the independent experts is summarised below in table 6.1.

Table 6.1: Application of compensation threshold by independent experts

DATE OF DIRECTION	HOW WAS THRESHOLD APPLIED?
1 December 2016	Per trading interval
1 December 2016 (additional compensation claim)	Per intervention event
28-29 March 2017	Per trading interval
25 April 2017	Per intervention event
29-30 August 2018	Per trading interval

Source: AEMC analysis of independent expert reports
Note: Reports available on AEMO website at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Market-event-reports

The variable application of the compensation threshold raises a number of issues, including consistency as between the determinations of independent experts, and consistency as between the approach adopted by independent experts and AEMO. But for CS Energy disputing its liability to pay the above amount to AEMO, and the publication of the Synergies report, there would be no transparency as to how this part of the NER is being implemented by AEMO. This has implications for market participants and for the amount of compensation cost passed through to consumers, and thus the National Electricity Objective.

AEMO has lodged a rule change request proposing that the $5,000 threshold should 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 in section 6.5.

QUESTION 8: COMPENSATION FOLLOWING INTERVENTION EVENTS

1. Should changes be made to the NER to increase clarity and consistency regarding the determination of compensation payments following AEMO intervention events?
2. Should the NER set out the basis for recovering affected participant compensation costs following RERT activations?

6.2 Transparency of the compensation process

The degree of publicly available information regarding the AEMO intervention event compensation process varies. This section explores the level of transparency for the existing compensation processes following directions and the activation of the RERT.

6.2.1 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.[265]

In accordance with clause 3.13.6A(b) of the NER, AEMO publishes aggregate data about the net compensation payable to directed and affected participants following a direction.[266] However, this data is very high level and does not show how much compensation has been paid to individual directed participants, and to or by affected participants.

The quantum of compensation paid to individual directed and to or by 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 or affected participants), where an affected participant disputes the amount it is required to pay AEMO 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.[267]

Since January 2016, only five such independent expert reports have been prepared.[268] Of these, only two identify both the participant and the compensation payable.

While the NER do prohibit independent experts from including in their 'fair payment price' report the identity of a directed participant,[269] there is no such prohibition in the clause relating to other independent expert reports (e.g. where a directed or affected participant lodges a claim for additional compensation or disputes an amount payable to AEMO).[270] 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 claimant.[271]

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 impossible to estimate the amount of compensation paid to or by individual affected participants (following the issue of a direction or the exercise of the RERT).

265 Note that, as discussed in Chapter 3, there is a now significant back log of market event reports that are yet to be published by AEMO. This undermines the level of transparency prescribed by the Rules.

266 Available at http://www.nemweb.com.au/REPORTS/CURRENT/Directions_Reconciliation/

267 See clauses 3.15.7A and 3.15.7B of the NER.

268 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.

269 Clause 3.15.7A(c)(5) of the NER.

270 Clause 3.12.3(c)(5) of the NER.

271 AEMC, *Final Decision, Compensation Claim from Synergen Power Pty Ltd*, 8 September 2010

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.[272] This direction was issued to Pelican Point power station and lasted only four hours. It occurred at a time when the supply demand balance was tight, meaning that spot prices were high. When AEMO directed Pelican Point GT12 to come online, it constrained down the output of a number of other generation units in order to minimise the wider impact of the direction. Affected participant compensation would have been paid to these generators and potentially others whose dispatch targets were affected as a result of the direction.

Very little information is published as to which participants were affected by a given direction. Available information is limited to those participants, if any, to whom counteraction instructions were issued (these may be noted in AEMO's post event report), and any affected participants who make a claim to AEMO that necessitates the engagement of an independent expert. No information is provided about the amounts paid to or by those participants unless an independent expert report is prepared following a claim by a participant.

Compensation to both Pelican Point (as the directed participant) and the affected participants was paid for by market customers (and ultimately consumers) in South Australia. This figure is not included in the AEMO report relating to these events (it is not required to be). However, there may be value in incorporating such data in post event reports in order to improve transparency regarding the cost of interventions.

The cost of compensation associated with the growing number of system strength directions in South Australia is also significant, as indicated by ElectraNet's recent economic evaluation report which put the cost of directions related compensation at $34 million per annum.[273] However, it is very difficult to ascertain accurately the cost to consumers of directions based on the data made publicly available by AEMO.

This $34 million figure reflects the *additional* costs (the 'compensation recovery amount' or CRA) that need to be recovered from market customers, noting that the trading amounts retained by AEMO under clause 3.15.8(b) comprise a portion of the amount that is paid out to directed participants. The difference between the trading amounts retained and the 90th percentile price compensation owing is the amount that needs to be recovered from market customers via the CRA to cover the cost of compensating directed participants. The CRA also includes funds required to cover the net cost of compensating affected participants, and the cost to AEMO of retaining independent experts to determine larger compensation claims.

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

272 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

273 ElectraNet, *Addressing the system strength gap in SA,* February 2018, p. 20. This is discussed further in Chapter 7.

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.

6.2.2 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 no compensation was paid in relation to the RERT activation in Victoria on 30 November 2017, $170,000 in compensation was payable in relation to the RERT activation in Victoria and South Australia on 19 January 2018.[274]

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.[275] 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.

The Commission is also considering the transparency of RERT costs more broadly in the Enhancement of the RERT rule change process. The draft rule, published in February 2019, makes a number of changes to the existing reporting requirements for the RERT, including RERT costs, in order to improve transparency and the timely provision of information regarding the RERT.[276]

> QUESTION 9: TRANSPARENCY OF THE COMPENSATION PROCESS
>
> 1. Do you consider current arrangements to be appropriate, or might there be benefits in increasing the level of transparency surrounding the quantum of compensation costs paid to directed and affected participants?

274 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.

275 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.

276 Further information is available at https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader

   a. For example, should information be included in post-event reports as to the compensation costs associated with intervention events?
   b. Should compensated participants be identified?
2. Should changes be made to the NER to facilitate this (in addition to AEMO processes)? If not, why not?

6.3 Affected participant compensation

The extensive use of directions for system strength in South Australia raises questions regarding the extent of compensation payments to affected participants. This in turn raises a more fundamental question as to whether compensation should be paid to (or by) participants affected by interventions given that generators in the NEM have no right to be dispatched in the wholesale market.

BOX 1: CURRENT ACCESS ARRANGEMENTS IN THE NEM

Currently in the NEM, generators have a right to negotiate a connection to the transmission network, but no right to be dispatched in the wholesale market and so earn revenue (this is otherwise known as "open access"). The service that a connecting generator is ultimately negotiating for with a TNSP is power transfer capability at the connection point, not the ongoing use of the shared transmission network to access the market.

Generators have no guarantee that they can export all of their output to the system at any given time. Instead, generators earn money by being dispatched through the wholesale market that is run by AEMO. AEMO's market dispatch engine seeks to maximise the value of trade given the physical constraints of the power system. As a consequence, generators are not required to pay for the cost of transmitting the electricity they produce.

Each generator in a particular region receives revenue at the clearing price (known as the"regional reference price") for the electricity delivered - even when that clearing price is above the price it offered into the market. In this way, the spot market coordinates the physical dispatch of generation and all generators earn at least their offer for each unit of electricity delivered. If a generator is not dispatched they cannot earn revenue from the spot market. Since generators have no rights to earn revenue in the wholesale market, they also do not have a right to be compensated for not being dispatched.

Source: AEMC

As noted earlier, when AEMO issues a direction or activates the RERT, it identifies *affected participants* – i.e. those participants whose output is affected as a result of the direction. An affected participant's output may be higher or lower as a result of the direction. If AEMO has implemented a counteraction, the number of affected participants may be small. If no counteraction has been implemented, the number of affected participants may be significant.

Under the current Rules, affected participants receive from, or must pay to, AEMO "…an amount as determined in accordance with this clause 3.12.2 that will put the *Affected Participant* in the position that the *Affected Participant* would have been in … had the *AEMO intervention event* not occurred".[277]

A direction is a way of meeting, or satisfying, a physical constraint on the system, where that constraint is not, or cannot, be represented in NEMDE. If it were possible to implement the system requirements as constraints AEMO would do so. In that case, there would be no compensation for being constrained down, because generators have no right to be dispatched in the NEM.

The principle that compensation is not payable for being constrained off is evident in clauses 3.9.7 (a) and (b) of the Rules, which state that:

> (a) In the event that a *network constraint* causes a *scheduled generating unit* to be *constrained-on* in any *dispatch interval*, that *scheduled generating unit* must comply with *dispatch instructions* from *AEMO* in accordance with its availability as specified in its *dispatch offer* but may not be taken into account in the determination of the *dispatch price* in that *dispatch interval*.
>
> (b) A *Scheduled Generator* that is *constrained-on* in accordance with clause 3.9.7(a) is not entitled to receive from *AEMO* any compensation due to its *dispatch price* being less than its *dispatch offer price.*

In other words, in the event that a generator is constrained on due to a network constraint, that generator is not entitled to receive compensation. Instead, generators in the NEM have a right to negotiate a connection to the shared transmission network but no right to be dispatched.

This raises the question of why participants affected by directions are treated differently to participants under the normal dispatch of the system. Generators do not receive compensation for being constrained off as a result of a network or other constraint. For example, output from South Australian wind farms is constrained above certain levels and no compensation is payable.[278] This is in contrast to the situation where generators typically receive compensation when they are constrained off because of a direction (see further below), a related counteraction or NEMDE optimisation in the wake of a direction.

In South Australia, certain combinations of synchronous generators must be online in order to maintain minimum levels of system strength. These combinations cannot easily be formulated as one or more constraints in NEMDE. Instead, AEMO uses directions as a means of meeting the physical requirements on the system to keep it secure. However, had the goal of keeping the system secure been achieved by implementing constraints, or through compliance with the minimum system strength framework, no affected participant compensation would be payable.

277 Clause 3.12.2(a)(1) of the NER.

278 In the third quarter of 2018, 10 per cent of SA wind was spilled due to these constraints which bound 26 per cent of the time.

Under the minimum system strength framework, if a TNSP contracts with a generator to provide system strength services, the generator can be constrained on as required by AEMO under clause 5.20C.4 of the NER. As a result of delivering system strength services via a constraint rather than via a direction, no affected participant compensation is payable to other generators whose dispatch targets are impacted as a result of the generator being constrained on.

The Commission is also aware that, in at least one instance, no compensation was payable to a participant who was directed to reduce output. This raises questions about the appropriateness of paying compensation to affected participants when their output is reduced not as a result of a direction but due to NEMDE optimisation subsequent to a direction.

On 1 December 2016, Mortlake power station was constrained off in order to maintain system security. Synergies Economic Consultants were engaged to determine the fair payment price (under clause 3.15.7A) for the service provided pursuant to the direction. Synergies concluded that no compensation was payable because "the NEM does not compensate generators that are constrained off, and that there is no clear exception to this principle when the instruction to reduce output or shut down results from a direction rather than in the process of implementing central dispatch".[279]

When Mortlake power station subsequently lodged a compensation claim for loss of revenue (under clause 3.15.7B), Synergies again concluded that no compensation was payable. This was on the basis that clause 3.15.7B(a)(1) refers to compensation being payable for loss of revenue incurred as a result of the *provision of the service under direction*. Synergies concluded that no relevant service had been provided and thus no compensation was payable for loss of revenue.[280]

Given this, questions arise as to the justification for compensating affected participants when their dispatch targets differ as between the dispatch run and intervention pricing run. If a reduction in Mortlake's output due to a security direction is not compensable, then should compensation be payable when dispatch targets differ as between the dispatch run and a counterfactual scenario (the intervention pricing run) which would, if realised, result in an insecure power system?

If NEMDE did not adjust dispatch targets in the wake of an intervention event, the result could be an insecure power system (as too much generation relative to demand can lead to frequency issues). As such, NEMDE optimisation of dispatch targets is a necessary step to maintain system security.

In considering the questions below, regard will need to be had for the findings of the AEMC's December 2018 report on *Coordination of Generation and Transmission Investment*. That report identifies important issues regarding the current arrangements for generator access and congestion management, and recommends a staged approach to reform of these arrangements. Any reforms to current access arrangements could have implications for the appropriate approach to compensating participants affected by interventions. (For example,

279 Synergies, *Final report on compensation related to directions that occurred on 1 December 2016*, June 2017, p. 13.

280 Synergies, *Final report on additional compensation claims arising from AEMO directions on 1 December 2016*, August 2017, p. 13.

in a world where generators can purchase firm access to the network, they would likely receive compensation for being constrained off as a result of a network constraint. For those participants who have not purchased firm access, they would not receive compensation.) Reforms to the compensation framework will have to be considered alongside the development of reforms to the access arrangements.

QUESTION 10: COMPENSATION FOR AFFECTED PARTICIPANTS

1. Should compensation be payable to affected participants? If so, why? If not, why not?
2. Should there be any distinction in the NER between intervention events that respond to reliability events and those that respond to security events (noting that constraints may not be suitable to respond to reliability events but may be suitable substitutes in the case of system security events)?
3. Are there any other approaches that should be considered?

6.4 Quantum of compensation for directed participants

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 participants for their services and, on the other, the level of compensation costs imposed on consumers. A framework that over-compensates generators may create incentives for generators to bid unavailable and await a direction from AEMO, with flow on effects for costs facing consumers.

A 2018 AER compliance report raises questions about generator behaviour in the lead up to directions being issued, stating that the AER is 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 NER. Further, the AER is examining whether this has led AEMO to issue directions to generators to remain synchronised, to ensure that the market remains in a secure operating state.[281]

Directed generators currently receive a predetermined level of compensation when they are directed. This level of compensation is equal to the difference between their output/load when directed, and their output/load had they not been directed multiplied by the 90th percentile of prices in the preceding 12 months. Box 2 sets out the process for calculating the compensation payable to a directed participant.

281 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."

BOX 2: COMPENSATION PAYABLE TO A DIRECTED PARTICIPANT

Clause 3.15.7(c) of the Rules sets out the formula for determining the compensation payable to a directed participant as follows:

'Subject to clause 3.15.7(d) and clause 3.15.7B, the compensation payable to each Directed Participant for the provision of energy or market ancillary services pursuant to a direction is to be determined in accordance with the formula set out below:

DCP = AMP x DQ

Where:

DCP = the amount of compensation the Directed Participant is entitled to receive;

AMP = the price below which are 90% of the spot prices or ancillary service prices (as the case may be) for the relevant service … in the region to which the direction relates, for the 12 months immediately preceding the trading day in which the direction was issued; and

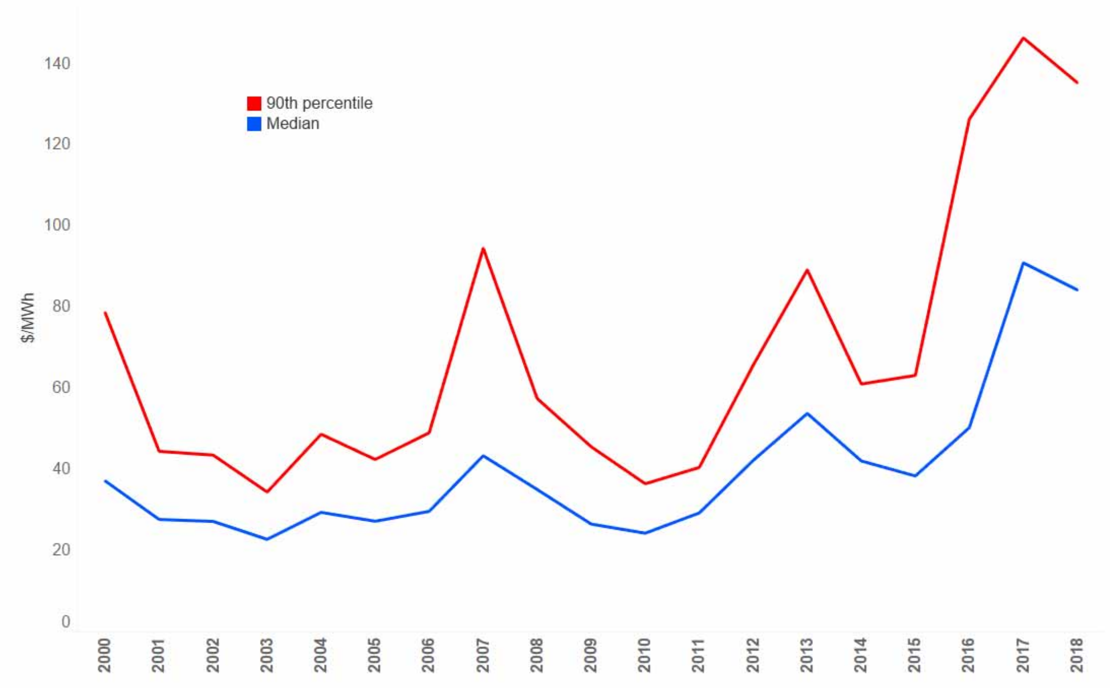
DQ = is either:

(A) the difference between the total adjusted gross energy delivered or consumed by the Directed Participant and the total adjusted gross energy that would have been delivered or consumed by the Directed Participant had the direction not been issued; or

(B) the amount of the relevant market ancillary service which the directed participant has been enabled to provide in response to the direction.'

The 90th percentile of prices is relatively high in comparison to the median price. Figure 7.1 compares the South Australia median price with the South Australia 90th percentile price on an annual basis from 2000 to 2018. In some years (e.g. 2016), the 90th percentile is more than double the median.

Figure 6.1: Median versus 90th percentile price - South Australia



Source: AEMC analysis

The 90th percentile provides a relatively high level of compensation. Moreover, the vast majority of interventions are currently occurring because of requirements for system strength in South Australia. During these interventions, spot prices are typically much lower than the 90th percentile of prices, because these interventions tend to occur during periods of high wind and/or low demand in South Australia.

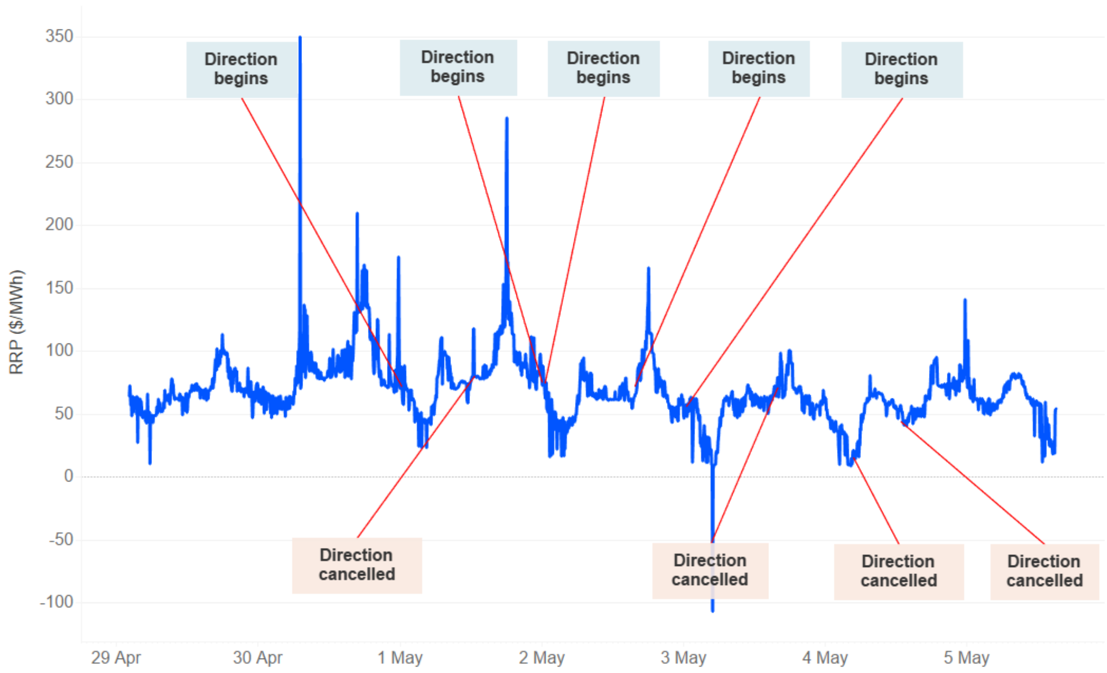
Another consideration in South Australia is that AEMO has published extensive information about the viable combinations of synchronous generators that will provide adequate system strength (namely, Torrens Island A and B, Pelican Point, Quarantine, Osborne, Mintaro and Dry Creek).[282] Market participants are therefore aware of which generators are required to maintain system security, and so can have confidence that, in some circumstances, they will be directed if they withhold their generation.

In addition, there is evidence that generators have asked for directions to be cancelled when the spot price rises, and have then withdrawn their generation when the spot price falls, or is expected to fall. This is not in breach of the NER as AEMO is required to cancel a direction as soon as it is no longer required (clause 4.8.9). However, it does reveal the impact of the compensation quantum on bidding behaviour. An example of this is shown in Figure 7.2 below, which shows part of an intervention that lasted from 24 April to 14 May 2018. As can

282 AEMO, *South Australian Transfer Limit Advice*, December 2018.

be seen, directions often begin as the spot price falls and are cancelled when the spot price is about to rise again.

Figure 6.2: Issuance and cancellation of directions during intervention in April/May 2018



Source: AEMC analysis

It follows that generators that are required to provide system strength have a strong incentive (being the difference between the spot price and the 90th percentile price) to withdraw their generation and await direction (as foreseen by the NEMMCO/NECA directions review discussed in Chapter 5). This has implications for the compensation costs to South Australian consumers, an issue to which AEMO refers in its rule change request relating to the $5,000 compensation threshold. In its rule change request, AEMO states that the proposed change (i.e. making the $5,000 threshold apply per intervention event rather than per trading interval) "strikes a fair balance between the interests of market participants and consumers. If this is a concern, then the appropriate level of compensation at the 90th percentile should be considered for situations where directions are common place." [283]

One alternative approach to 90th percentile compensation would be that adopted to compensate participants following a market suspension. This approach compensates generators by reference to the short run costs they are deemed to have incurred.[284] Potential benefits of such an approach are:

283 AEMO, *Electricity Rule Change Proposal – Threshold for participant compensation following market intervention*, December 2018, p. 6.

284 More information about this framework can be found in AEMC, *Participant compensation following market suspension - Rule determination*, 15 November 2018.

- avoiding potential over-compensation to generators which may create an incentive to withdraw their generation and await direction. This would reduce reliance on the labour-intensive directions process and, importantly, reduce compensation costs borne by consumers;
- better accommodating the different costs of various generators (since the starting point of the compensation framework is the short run marginal cost of each generator type, rather than a price percentile which is indifferent to individual generator costs); and
- making the compensation immune to potential future changes in the spot prices arising from changes in the generation fleet: i.e. increasing penetration of renewables might eventually lower the 90th percentile of prices to a point below some thermal generators' SRMC (particularly in circumstances where synchronous condensers reduce the need for thermal generators to provide services such as system strength).

QUESTION 11: QUANTUM OF COMPENSATION FOR DIRECTED PARTICIPANTS

1. Is the compensation framework for directed generators creating perverse incentives?
2. Is the use of the 90th percentile appropriate given the increasing penetration of variable renewable generation? Would another level of compensation be appropriate?
3. Would it be preferable to determine the quantum of compensation through a different means, such as estimated costs per participant?

6.5 AEMO's rule change request

AEMO has submitted a rule change request proposing that the $5,000 compensation threshold for affected and directed participants be changed so that it applies per intervention event, rather than per trading interval. (The threshold only applies to directed participants when they make a claim for additional compensation. By contrast, the threshold applies to the whole of the compensation payable to or by affected participants.)

AEMO notes that, under the current approach, where an intervention event is of a long duration, the calculated participant compensation amount could far exceed $5,000 over the entire event without breaching the $5,000 threshold in an individual trading interval. An example of this is the CS Energy claim discussed earlier. In total, the compensation amount was around $280,000. However, the independent expert engaged to review the claim concluded that CS Energy was not liable to repay this amount to AEMO (as AEMO had advised) because the $5,000 per trading interval threshold was not considered to have been exceeded.

AEMO considers that "the potential for material under-compensation creates operational and financial risks for participants"[285] and that the proposed rule change "would efficiently incentivise participants to work collaboratively with AEMO without having to weigh this against the risk of financial losses from an intervention event".[286]

285 AEMO, *Electricity Rule Change Proposal*, op cit, p. 5.

6.5.1 NEO assessment

The Commission's assessment of the above rule change request, together with the RRN test rule change request discussed in Chapter 5, must consider whether the proposed rule will promote the NEO as set out under section 7 of the National Electricity Law (NEL) as follows:

> 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:
>
> - price, quality, safety, reliability and security of supply of electricity; and
> - the reliability, safety and security of the national electricity system.

Based on a preliminary assessment of the issues raised by the rule change request, the Commission considers that the relevant aspects of the NEO are efficient investment in electricity services and the price of supply of electricity. The issue of investment is relevant in considering this rule change request since the amount of compensation received by directed and affected participants has a bearing on the financial risks facing participants and thus investment signals. The price of electricity is relevant to the rule change request as compensation payments have a bearing on costs passed through to consumers.

6.5.2 Principles

The Commission has set out a number of principles to guide the assessment of the rule change request in addition to the NEO.

1. Equity – does the proposed approach strike a fair balance between the interests of directed and affected participants, and consumers?
2. Efficiency – does the proposed approach achieve the objective of helping to recover the administrative outlays associated with processing compensation claims, and dissuading immaterial claims?
3. Transparency and predictability – is it clear how the proposed approach will affect the interests of market participants?
4. Risk allocation – does the proposed approach appropriately allocate risk to those parties best able to manage them?

6.5.3 Issues to consider in relation to the rule change request

In considering the proposed rule change, it is appropriate to have regard to the impact of the threshold on directed participants and affected participants in turn. In the case of directed participants, the threshold applies to claims for additional compensation where the automatic compensation (calculated based on the 90th percentile price) has not been adequate to cover the participant's costs. In such cases, and particularly where the intervention event is of a long duration, the threshold could have an adverse impact on the financial position of the directed participant (noting that they are subject to compulsion and cannot optimise their position). Accordingly, it may be considered appropriate to adjust the threshold for directed

286 ibid, p.6.

participants in the manner proposed, even though this will result in greater costs being passed through to consumers.

By contrast, the position of affected participants is qualitatively different. They are not subject to compulsion, as are directed participants, and have the capacity to influence their dispatch targets through rebidding. This was recognised by the NEMMCO/NECA Directions review report which noted that "there exists potential for third parties [affected by a direction] to maximise their payment by re-bidding their capacity into higher price bands in expectation that a market direction will be issued".[287] Affected participants are able to optimise their position in this way and this has a bearing on whether it is appropriate to adjust the threshold in such a way that payments to affected participants would increase at the cost of consumers.

A key challenge in determining the optimal approach to the compensation threshold is that there is no prescribed method by which to determine the appropriate length of AEMO intervention events. These can range from a few hours to, in one case, 21 days (in April-May 2018). The result is that the application of the threshold, if applied per intervention event, can have widely varying impacts (both on generators and consumers), depending on the length of each given intervention event.

Further, it is important to consider whether, if applied per intervention event rather than per trading interval, the threshold should remain at the level of $5,000. Arguably, and as noted in the SW Advisory Report referenced in the AEMO rule change request and the Harding Katz report discussed in section 7.1.3,[288] the threshold should be set at a higher level if it is to apply per intervention event, rather than per trading interval.

An alternative approach was adopted in the AEMC Final Determination regarding Participant compensation following market suspension. Rather than apply a threshold per trading interval or per market suspension, that framework imposes a fee per claim (to be determined by AEMO under its Market Suspension Compensation Methodology). This applies when a participant lodges a claim for additional compensation but does not apply to automatically calculated compensation. This is designed to achieve the objective of the compensation threshold, namely, deterring immaterial claims and helping to recoup the administrative outlays associated with determining compensation claims, and may present an alternative option in the context of the current rule change proposal.

QUESTION 12: CHANGING THE COMPENSATION THRESHOLD

1. Should the $5,000 threshold apply per trading interval, as currently, or per intervention event, as proposed by AEMO?

287 NEMMCO and NECA, op cit, p.25.

288 The consultants considered 'there is a case for seeking an amendment to clause 3.15.7B(a4) (and possibly 3.12.2(b)) so that the threshold applies at the direction level. It is less clear what this threshold amount should be, noting that it may be substantially more than $5,000.'

2. If the threshold is to apply per event, should the quantum remain as currently or change? If the latter, how should the quantum be determined? For example, should it be a set amount or determined based on case specific criteria such as the length of the intervention event or the quantum of the compensation claimed or payable?
3. Should the same approach be adopted with respect to both affected and directed participants or does a differentiated approach warrant consideration?
4. To promote transparency and predictability, should there be any more clarity regarding how AEMO determines the length of a given intervention event?

7 MINIMUM LEVELS OF SYSTEM STRENGTH AND INERTIA

In the *Managing power system fault levels* final rule, the Commission introduced a framework for AEMO to determine a minimum level of system strength necessary to maintain the power system in a secure operating state for each fault level node in a region.[289] If there is insufficient system strength in a region, the framework obliges AEMO to declare a fault level shortfall for that region, and transmission network service providers (TNSPs) to make available system strength services that when enabled would address the fault level shortfall.[290]

This framework came into effect on 1 July 2018. The final rule also set out transitional arrangements that allowed the framework to be applied prior to 1 July 2018. In October 2017, AEMO declared a system strength related NSCAS gap in South Australia, and ElectraNet elected to treat this declaration as a notice of a fault level shortfall for South Australia under the new framework.

Also on 1 July 2018, a similar framework was introduced for minimum and secure operating levels of inertia in the final rule for *Managing the rate of change of power system frequency*.[291]

ElectraNet has committed to building synchronous condensers to address the declared system strength or fault level shortfall in South Australia.[292] Prior to the construction and commissioning of these synchronous condensers, AEMO has been issuing directions to provide for the minimum required level of system strength in South Australia. These directions are the cause of the majority of the interventions discussed in Chapter 3.

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

In December 2018, AEMO declared a shortfall in inertia in South Australia.[293] In order to address this shortfall, AEMO has recommended that ElectraNet fits flywheels to the proposed synchronous condensers and considers opportunities to meet part of the shortfall through developments that provide fast frequency response (FFR).

289 AEMC, *National Electricity Amendment (managing power system fault levels) Rule 2017 No. 10*

290 The term system strength is used interchangeably with fault level in this chapter. Fault level, or three-phase fault level, can be used as a measure of system strength.

291 AEMC, *National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017 No. 9*.

292 ElectraNet, *Information Sheet - Power System Strength*, May 2018.

293 AEMO, *National Transmission Development Plan*, December 2018, pp. 4-5.

This chapter raises aspects of the minimum system strength and inertia frameworks for consideration. Namely, whether the timeframes and level of flexibility in these frameworks are sufficient to lead to optimal outcomes when addressing emerging system strength and inertia shortfalls as they arise in NEM regions. In particular, the Commission intends to explore whether changes can be made to these frameworks to limit the practice of AEMO intervening in the market in order to maintain system security.

The minimum system strength rule also places an obligation on new connecting generators to "do no harm" to the level of system strength necessary to maintain the security of the power system. The "do no harm" aspects of the system strength rule are not the focus of this investigation. However, the Commission notes that this aspect of the framework may be resulting in some issues relating to the connection of new generators. As such, this will be considered in the Commission's future work program.

The Commission also notes that, beyond the minimum levels of system strength and inertia, additional system strength and inertia has the potential to provide economic benefits by alleviating constraints in the power system and thereby increasing levels of competition in the wholesale market. Additional system strength and inertia that provides economic benefits is also not being considered through this investigation. However, as part of its future work program, the Commission is proposing to explore options to value additional system strength and inertia and to design and potentially implement a mechanism to pay for these services.

For context, further information on the "do no harm" aspect of the rules and additional system strength and inertia for economic benefits is provided in sections 7.1.2 and 7.5 respectively.

This chapter is structured as follows:

- background to the development of the minimum system strength and inertia frameworks
- context for consideration
- the implementation of the framework for the minimum level of system strength
- issues raised for stakeholder feedback.

7.1 Background

This section outlines the minimum system strength and inertia frameworks. It provides detail on:

- a summary of the final rules
- the "do no harm" obligation
- the minimum level of system strength
- the transitional arrangements.

7.1.1 Summary of the minimum system strength and inertia final rules

On 19 September 2017, the Commission published the *Managing power system fault levels* ("system strength rule") and the *Managing the rate of change of power system frequency* ("inertia rule") final rules in response to the rule change requests submitted by the South Australian Government. The final rules require:

- AEMO to develop system strength and inertia requirements procedures. AEMO uses these procedures to determine:
    - the required three phase fault level at key locations in each transmission network necessary for the power system to be maintained in a secure operating state
    - the required inertia necessary to maintain any sub-network in a secure operating state.
- TNSPs to procure system strength or inertia services needed to meet the required level as determined by AEMO where a system strength shortfall or inertia shortfall exists. These services are then enabled operationally by AEMO as needed.

In relation to system strength specifically, the system strength rule requires:

- AEMO to develop system strength impact assessment guidelines that set out a methodology to be used by NSPs and generators when assessing the impact on system strength of a new generator connection.
- new connecting generators to "do no harm" to the security of the power system. This means new connecting generators should not adversely impact on the ability to maintain system stability or on a nearby generating system's ability to maintain stable operation. (This requirement applies regardless of whether AEMO has declared a system strength shortfall in a region.)

The "do no harm" aspects of the system strength rule are not the focus of this chapter. However, the Commission notes that this aspect of the framework may be resulting in some issues relating to the connection of new generators. As such, this will be considered in the Commission's future work program.

BOX 3: WHAT IS SYSTEM STRENGTH?

System strength is a characteristic of an electrical power system that relates to the size of the change in voltage following a fault or disturbance on the power system. When system strength is high at a connection point, the voltage changes very little when a change in load or generation occurs at the connection point. Low levels of system strength can jeopardise the ability of generators to operate correctly, thus impacting system security. System strength has been traditionally measured by the available fault current at a given location or by the short circuit ratio. System strength service is defined in Chapter 10 of the NER as "a service for the provision of a contribution to the three-phase fault level" at a given location in the transmission network.

A recent Grattan Institute report described system strength in lay terms as a property of the grid that "helps to prevent some shocks from becoming widespread. System strength refers to how robust voltage is to a shock. Voltage can fall rapidly if lines clash with one another or become electrically connected to the ground, because current flows through the fault (a short circuit) rather than to customers. This is most commonly caused by lightning or wind, or when transmission towers are damaged and fall. The rapid flow of current to a fault is called 'fault current', and is used to detect faults and trigger protection mechanisms.

"A strong system generates high levels of fault current, which reduces the effect of a fault on the voltage in its vicinity. As low voltages can cause generators to trip, this reduces the number of generators that might disconnect in response to the fault, and so the risk of load shedding. A strong system also makes it more likely that protection systems will correctly isolate faults, reducing the duration and extent of voltage dips."

Connecting synchronous generators to a network will increase system strength as they can contribute large volumes of fault current.

System strength differs from:

- frequency (which relates to the rotational speed of the synchronous generators connected to the system),
- inertia (which refers to the inherent capacity of large spinning machines to dampen the rate of change of frequency following a contingency event that produces an imbalance in active power supply and demand) and
- voltage (which is regulated by the injection or absorption of reactive power to manage the voltage at a given point in the power system).

Source: The Grattan Institute, *Keep calm and carry on: managing electricity reliability*, February 2019, pp. 29-30.

This chapter will focus on the minimum system strength framework. However, as the minimum system strength framework and minimum inertia frameworks are highly consistent, consideration of the minimum system strength framework would also reasonably apply to the minimum inertia framework.

The system strength rule established two frameworks for addressing the causes of system strength issues: a decline in the amount of system strength typically provided by existing generators; and an increase in the amount of system strength needed as new generators connect to the system. The difference between the two frameworks are set out in the table below.

Table 7.1: Two frameworks in the *Managing power system fault levels* final rule

	MINIMUM LEVEL OF SYSTEM STRENGTH	'DO NO HARM' OBLIGATION FOR CONNECTING GENERATORS
System strength related issue addressed	Retiring generators that reduce the amount of system strength typically provided.	A new generator connecting to the power system which results in the existing amount

	MINIMUM LEVEL OF SYSTEM STRENGTH	'DO NO HARM' OBLIGATION FOR CONNECTING GENERATORS
	Changes in network conditions that change the level of system strength. Changes in typical generation patterns that affect the level of system strength.	of system strength being shared by more generators. This can result in these generators being unable to operate stably.
How the issue is identified	AEMO is required to determine the level of system strength needed at designated fault level nodes in a region for secure system operation. AEMO is required to declare a fault level shortfall where the level of system strength typically provided is less than what is required for secure operation of the power system.	AEMO is required to publish a "do no harm" guideline that sets out how NSPs should assess whether a connecting generator would have an adverse system strength impact. During the connection process, NSPs must identify whether a new connecting generator would have an adverse system strength impact.
How the issue is remedied under the framework	When AEMO declares a fault level shortfall, the relevant TNSP is required to make available system strength services that when enabled will address the shortfall.	New connecting generators are required to remedy any adverse system strength impacts.

The two frameworks in the final rule, as well as the transitional arrangements for the final rule, are set out in more detail below.

7.1.2 "Do no harm" obligations on new connecting generators

The "do no harm" requirements for new connecting generators commenced on 17 November 2017, coinciding with a requirement on AEMO to publish an interim set of system strength impact assessment guidelines. In accordance with the final rule, AEMO consulted on and published a final set of these guidelines by 1 July 2018.

The final rule places an obligation on new connecting generators to "do no harm" to the level of system strength necessary to maintain the security of the power system.[294]

When a new generator is negotiating its connection with the relevant NSP, a system strength impact assessment is required. This involves the NSP assessing the impact of the connection of the generating system on the ability of the power system to maintain stability and for other generating systems to maintain stable operation, including following any credible contingency event or protected event.

This assessment is undertaken using the methodology and power system model set out in the system strength impact assessment guidelines developed and published by AEMO. These guidelines specify what AEMO considers to be an "adverse system strength impact", i.e. "doing harm". They also provide guidance on the different network conditions, dispatch patterns and other relevant matters that should be examined when undertaking an assessment.

A dispute resolution mechanism has been put in place which allows a new connecting generator to dispute the application of the system strength impact assessment guidelines, whether the model used in the assessment of the system strength impact was reasonably appropriate, or the results of a system strength impact assessment made using those guidelines.[295]

The new connecting generator is required to fund the provision of any required system strength connection works or remediation schemes to address the impact of its connection on system strength. This places an incentive on new connecting generators to either design their systems to operate at lower levels of system strength or to connect at locations within the network where there is sufficient system strength.

The obligation on new connecting generators only applies at the time the connection is negotiated, based on the information available at the time. Once established, the obligations are incorporated into the connection agreement between the generator and the NSP.

7.1.3 Minimum level of system strength

The intent of the minimum system strength framework is to make sure there is sufficient system strength in the power system to maintain secure operation.

In the final rule, an obligation was placed on AEMO to develop a methodology ("system strength requirements methodology") that sets out how it will determine the system strength needed in each region ("system strength requirements"). When AEMO specifies the system strength requirements for a region, it must define this in terms of:

- the "fault level nodes" in the region, being the location on the transmission network at which the fault level must be maintained at or above a level determined by AEMO
- for each fault level node, the minimum three phase fault level.

294 The 'do no harm' obligation applies to generators connecting to both the transmission network and distribution network under Chapter 5 (i.e. under rule 5.3 and rule 5.3A) of the NER. It does not apply to the connection of micro-embedded generation, such as residential solar.

295 Clause 5.3.4B(d) of the NER.

In each region, AEMO has selected fault levels nodes based on four criteria: areas near metropolitan load centres, synchronous generation centres, areas with high levels of asynchronous generation connection/interest, and areas which are electrically remote from synchronous generation.[296]

Following the determination of system strength requirements for each region, AEMO must undertake an assessment of any fault level shortfall. In assessing the extent of a fault level shortfall, AEMO must have regard to typical patterns of centrally dispatched generation. Clause 5.20C.2 requires the following:

> (a) *AEMO* must as soon as practicable following its determination of the *system strength requirements* for a region under clause 5.20C.1 assess:
>
> (1) the *three phase fault level* typically provided at each *fault level node* in the *region* having regard to typical patterns of *dispatched generation* in *central dispatch*;
>
> (2) whether in *AEMO's* reasonable opinion, there is or is likely to be a *fault level shortfall* in the *region* and *AEMO's* forecast of the period over which the *fault level shortfall* will exist; and
>
> (3) where *AEMO* has previously assessed that there was or was likely to be a *fault level shortfall*, whether in *AEMO's* reasonable opinion that *fault level shortfall* has been or will be remedied.
>
> (b) In making its assessment under paragraph (a) for a *region*, *AEMO* must take into account:
>
> (1) over what time period and to what extent the *three phase fault levels* at *fault level nodes* that are typically observed in the *region* are likely to be insufficient to maintain the *power system* in a *secure operating state*; and
>
> (2) any other matters that AEMO reasonably considers to be relevant in making its assessment.

The approach used by AEMO to identify a potential shortfall is discussed further below in section 7.3.2.

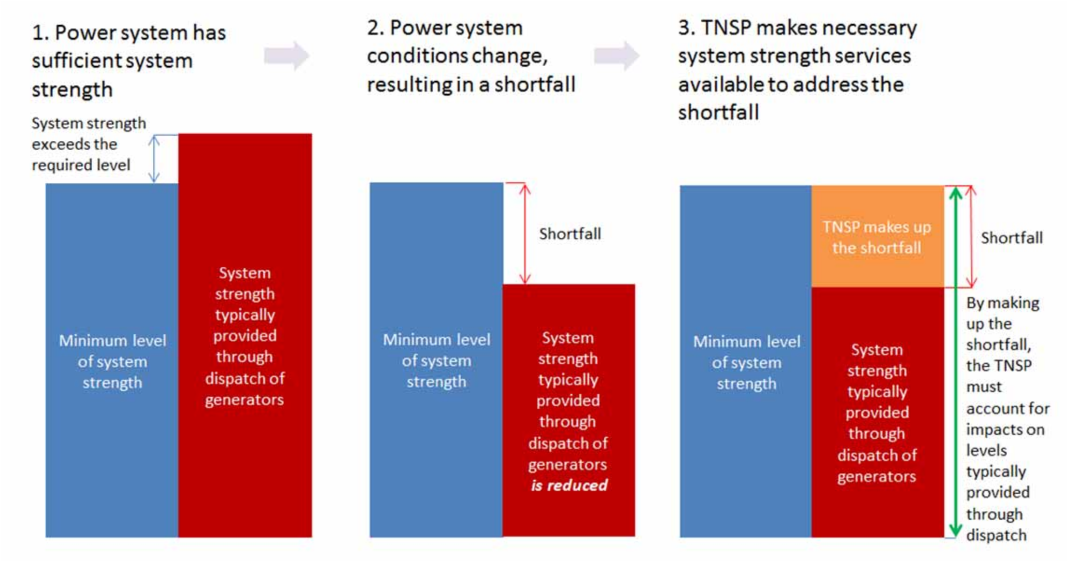
If AEMO assesses that there is, or is likely to be, a shortfall, it is required to publish a notice and give it to the relevant TNSP. This notice must specify the extent of the fault level shortfall and the date by which the TNSP must provide services to address the shortfall (the services to address the fault level shortfall are "system strength services"). This date must not be earlier than 12 months after the notice is published (unless otherwise agreed), to provide the TNSP with sufficient time to make the services available.

Following receipt of a notice from AEMO declaring a shortfall, the TNSP must make system strength services available to AEMO in accordance with the specification in the notice. These services must cover the system strength requirements for the region and must be provided

296 AEMO, *System Strength Requirements Methodology*, June 2018, p. 15.

by the date specified by AEMO. Figure 7.1 shows the process through which a fault level shortfall may arise, and how it can subsequently be addressed by the TNSP.

Figure 7.1: Fault level shortfall



When procuring these services, the TNSP is required to identify and implement the least cost option or combination of options. If AEMO requires the services less than 18 months after the publication of the notice and, if the TNSP is not already under an obligation to provide system strength services for that fault level node, the TNSP is not required to undertake a regulatory investment test (RIT-T) for the relevant transmission investment. This shortens the process by which the TNSP assesses the combination of operational expenditure (e.g. contracting with synchronous generators) and network expenditure (e.g. building a fault level source on the network) that best addresses the shortfall within the 18-month timeframe.

Once the TNSP procures the necessary system strength services, the operational control of the services is passed to AEMO to manage the security of the power system in that region.

7.1.4 Addressing the system strength shortfall in South Australia

On 13 September 2017 (six days prior to the publication of the *Managing power system fault levels* final rule) AEMO declared a network support and control ancillary service (NSCAS) gap[297] in relation to system strength in South Australia through an update to its 2016 National transmission network development plan (NTNDP).

297 The NER has a framework for addressing NSCAS gaps. NSCAS gaps are shortages of services that can be provided by a network, e.g. a shortage of reactive power provided in a part of the network. NSCAS gaps can either be for system security, reliability or market benefit. Where a gap is declared, the relevant TNSP has the option of deciding to meet the gap or not. If the TNSP elects not to, and the NSCAS gap is for security or reliability, AEMO can meet the gap as a procurer of last resort.

As the NSCAS gap could not be addressed under the new system strength framework,[298] transitional arrangements were introduced that afforded AEMO the flexibility to withdraw the NSCAS gap, and reissue it. AEMO subsequently withdrew the NSCAS gap and reissued it after the commencement of the final rule, which allowed the gap to be treated as a fault level shortfall under the transitional arrangements in the final rule.[299]

Following the reissuing of the gap, ElectraNet committed to meeting it. ElectraNet evaluated potential options for addressing the shortfall. Their analysis identified:[300]

- contracting with generators to meet the shortfall would not be economic
- installing synchronous condensers was the least cost option
- there were no other options available in the required timeframe.

ElectraNet sought offers from market participants in South Australia to meet the minimum system strength requirements but ultimately determined that generator contracting was not an economically viable solution and proposed that AEMO continue with directing generation in the short term. ElectraNet suggested that fast-tracked investment in synchronous condensers would be the most efficient solution in the medium term. As at May 2018, ElectraNet envisaged that the synchronous condensers would be constructed and commissioned "by 2020".[301] ElectraNet liaised with the AER and AEMO during this process.[302]

In February 2019, ElectraNet published an economic evaluation report in which it again assessed options to address the system strength shortfall in South Australia. The three options considered were: continued reliance on AEMO directions to ensure adequate system strength, generator contracting, and installation of high inertia synchronous condensers. ElectraNet again concluded that the preferred option is to install synchronous condensers (and, in the interim, for AEMO to continue to issue directions).[303]

ElectraNet's report estimates the cost of contracting with generators to be $85 million per annum, while the cost of directions was estimated at $34 million per annum. However, the report notes that the $34 million figure "excludes the broader impact of intervention pricing on wholesale market prices ... which represents an additional cost ultimately borne by customers. AEMO estimates the cost impact of intervention pricing on wholesale market outcomes as a result of issuing directions for system strength as at September 2018 exceeds $270m. This is additional to the impacts of constraining wind generation."[304]

298 The final rule excluded from the definition of a "NSCAS need" any requirement for system strength services to address a fault level shortfall. The Commission considered that it was undesirable to have two frameworks in the NER for the provision of equivalent services, that is, both system strength services provided under the NSCAS framework and under the new framework.

299 AEMO, *Second update to the 2016 National transmission network development plan*, October 2017.

300 ElectraNet, *Power system strength: information sheet*, May 2018.

301 ibid.

302 In its Quarterly Compliance Report for the first quarter of 2018, the AER stated: "Based on the information provided, ElectraNet has demonstrated that it took reasonable steps to economically assess and make available the least cost option to provide system strength services through first seeking offers for these services from market participants and ultimately proposing the synchronous condenser solution, in accordance with clause 5.20.3C(1) of the Electricity Rules". See AER, *Quarterly Compliance Report: National Electricity and Gas Laws, 1 January - 31 March 2018*, p. 18.

303 ElectraNet, *Addressing the system strength gap in SA: Economic evaluation report*, February 2019

304 ibid, p. 21. The impact of wind constraints is discussed further in section 7.5.

While the basis on which this figure is calculated is not set out in the ElectraNet report, the Commission surmises that it reflects the difference between spot prices as set by the intervention pricing run and prices produced by the dispatch run when system strength directions are in effect. The Commission has also analysed the impact of intervention pricing on spot prices across the NEM as discussed in section 4.7 and that analysis produces similar figures (noting that these are likely to represent an upper limit of the impact of intervention pricing for the reasons outlined in section 4.7).

In comparing options for the provision of system strength services, the Commission considers it important to consider all relevant cost components.

For options such as the provision of synchronous condensers, the key costs will include capital and operating costs. For generator contracting, the total cost will include the cost of the contract charges (which will be passed through to consumers via TNSP charges), as well as the trading amounts that would be paid to generators when they are constrained on by AEMO (since these will also be passed through to consumers, albeit not directly, through wholesale energy charges).[305]

While reliance on directions issued by AEMO is not an option available to a TNSP under the minimum system strength framework, directions may nevertheless be considered by stakeholders when the only alternative for addressing a system strength shortfall is found to be costly. As discussed in section 7.4.2, the Commission considers it important to identify shortfalls early enough that reliance on more costly options or directions does not become necessary. Nonetheless, to the extent that directions are considered as a means to address system strength inadequacy, it is important that they are costed appropriately.

This would involve costing the compensation payable to directed participants, the net compensation paid to affected participants, and any fees payable to independent experts to assess claims. It will also be important to factor in the trading amounts retained by AEMO (which, in the case of directions, will be impacted by intervention pricing – an effect that is not present under the generator contracting option).[306]

It will also be important to have regard for the wider impacts of directions, in particular the impact of intervention pricing on wholesale energy prices. Not taking such impacts into account in determining the least cost approach risks producing inefficient outcomes. While precise quantification of these impacts may not be possible, it is important that regard be had to their scale and potential impact on contract prices and thus energy costs facing consumers.[307] This could be done through sensitivity analysis – for example, considering at what point these wider impacts would alter the cost ranking of the options considered.

305 Trading amounts will not be passed through directly to consumers since the prices paid to generators are typically a function of hedge contracts between generators and retailers. However, expectations about future spot prices inform contract prices. As such, the amounts paid to generators are relevant in considering the costs ultimately passed through to consumers.

306 In 2018, AEMO retained trading amounts totalling $16.4 million that would otherwise have been paid to the generators directed to provide system strength services. These trading amounts reflect the impact of intervention pricing on the spot price during the period when directions were in effect. They are retained by AEMO so that they can be used to compensate directed participants (at the 90th percentile price) and affected participants. Where retained trading amounts are not sufficient to cover compensation costs, an additional "compensation recovery amount" is recouped from customers.

307 Particularly in South Australia where the impact of intervention pricing on spot prices is most marked, it is reasonable to suggest that future contract prices will be informed by the impact of intervention pricing on spot prices and will thus put upward pressure on future energy prices.

Period before synchronous condensers are installed

ElectraNet's economic evaluation report notes it will procure the first two synchronous condensers by mid-2020 while two further condensers, 'required to implement a full solution to address the declared system strength gap', will be in place by end 2020.[308] This lengthy lead time will increase the costs borne by consumers as a result of both directions-related compensation and intervention pricing impacts on wholesale energy prices.

This raises a question as to whether there would be value in changes being made to the rules governing intervention pricing and compensation. Such changes could mitigate the cost to consumers and distortionary impacts associated with relying on directions (for system strength or any other services not traded in the market) to ensure system security. While the immediate effect of such changes would have most impact in South Australia, they could also reduce costs and distortionary impacts in other regions (for example, Victoria) if in future directions are issued more frequently in response to declining system strength or other system security issues in those regions.

Figure 7.2 below compares the interim options available to secure system strength in South Australia and considers the costs associated with each, including in the event that changes are made to the current intervention pricing and compensation frameworks (as discussed in Chapters 5 and 6). The first row considers the cost of continuing to issue directions, and apply intervention pricing, while the second row considers the cost of generator contracting. The third row indicates the potential to lower the cost of directions through well targeted changes to the intervention pricing and compensation frameworks.

Figure 7.2: Interim options for securing system strength in South Australia and their costs

	Spot price and trading amounts	Other costs	Wider impacts
Directions with intervention pricing	Higher ($16.4m in 2018)	Lower (CRA amount of $34m)	Some portion of $71m impact on SA spot price in 2018
Generator contracting	Lower ($14.8m in 2018)	Higher (contract cost of $85m)	$0 as no intervention pricing is used
Directions without intervention pricing and with reduced compensation costs	Lower ($14.8m in 2018 based on removing impact on spot price of intervention pricing)	Lower (CRA of <$34m if affected participant compensation and/or directed participant compensation is reduced)	$0 if intervention pricing ceases to apply to directions for services that are not traded in the market

Source: AEMC analysis

Note: The $14.8m estimate of trading amounts is based, for the purpose of comparison, on the volume of energy generated under direction in 2018, multiplied by the price from the dispatch run of NEMDE. This price is lower than the intervention pricing run price (which accounts for the higher $16.4m trading amount in the 'directions with intervention pricing' option).

308 ElectraNet, *Addressing the system strength gap in SA: Economic evaluation report*, February 2019, p. 31.

7.2 Context for consideration

As synchronous generators change their operating patterns and continue to retire from the power system, the minimum system strength and inertia frameworks will become increasingly important for maintaining the secure operation of the power system. The application of the minimum system strength and inertia frameworks in South Australia, and the emergence of system strength issues in Victoria, highlight the increased importance of these frameworks.

The Commission intends to explore whether adjustments could be made to these frameworks to improve the flexibility with which they can be applied to address issues as they begin to emerge in other NEM regions. A more flexible framework may limit the need for the use of directions and interventions pricing, which can have unintended impacts on the wholesale price and investment signals.

7.2.1 Current and emerging issues

To date system strength related issues have predominantly been experienced in the South Australian power system. These issues were being experienced at the time the minimum system strength framework was introduced.

However, challenges relating to system strength are starting to emerge in other regions. For example, TasNetworks (the Tasmanian TNSP) has measures in place to maintain sufficient system strength and inertia to accommodate the unexpected loss of Basslink (the DC interconnector between Tasmania and Victoria) and the operation of asynchronous generation.[309] More recently, one direction (as at the time of writing) has been issued to a synchronous generator in Victoria to maintain sufficient system strength. The National transmission network development plant (NTNDP) released by AEMO in December 2018 highlights a number of regions across the NEM where system strength levels are falling as growing numbers of asynchronous generators connect to the network (discussed further in section 7.4.1).

As these issues emerge, there may be challenges accommodating them through the minimum system strength framework prior to the system strength related issue being sizable and regular enough to be considered a shortfall.

While a shortfall in inertia was declared in South Australia in December 2018, levels of inertia in other NEM regions do not appear to be a major issue at this time. (Inertia levels in Victoria are projected to fall below required levels in the near term but no shortfall has been declared given the low risk of Victoria becoming 'islanded' from the rest of the NEM.[310]) Nevertheless, the conclusions reached in this review in relation to the minimum system strength framework could equally apply to the minimum inertia framework.

309 TasNetworks, *Annual planning report 2018*, p. 20.

310 AEMO, NTNDP 2018, p. 18.

7.2.2 System strength issues differ across the NEM

The severity of system strength issues differs across the NEM. The system strength related issues experienced in South Australia are substantially more material than those currently being experienced elsewhere in the NEM. Unlike South Australia, Victoria has so far only experienced system strength related issues over a single weekend. These directions are covered in more detail in Box 4.

BOX 4: SYSTEM SECURITY DIRECTIONS IN VICTORIA

Between 16 and 18 November 2018, AEMO issued directions to generators in Victoria to maintain system security relating to voltage control and system strength.

While voltage control and system strength are strongly related, the two issues can be addressed by different solutions. For example, reactive power banks and static VAr compensators can be used to address voltage controls but may not provide fault current to address low system strength.

On 16 November 2018, AEMO directed a generating unit into service to assist with voltage control. The decision was based on system studies which indicated that:

- Due to a number of synchronous generating units being out of service, the management of post-contingent voltage violations at the Keilor terminal station did not meet the system security requirements.
- With another Victorian generator in service, the post-contingent voltage violations around the Keilor terminal station area would be mitigated and system security requirements would be met.

AEMO therefore issued a direction to a generator to manage network voltage control.

In the early hours of 17 November, another synchronous generating unit came out of service. Later that morning, AEMO required the directed generator to stay online to ensure sufficient system strength was available.

On 18 November 2018, AEMO directed another generator to manage network voltage control at Keilor terminal station.

These directions were prompted by periods of low demand, low prices, and synchronous plant outages. Without AEMO's intervention, these conditions would have resulted in insufficient in-service synchronous generation to maintain power system security in Victoria.

Source: AEMO, *System strength directions briefing,* 23 November 2018.

The experiences in South Australia and Victoria show that there is a difference in how the minimum system strength framework is applied throughout the NEM.

- In South Australia a shortfall has been declared and ElectraNet is in the process of addressing this shortfall under the minimum system strength framework.
- In other regions, including Victoria, system strength shortfalls have not been declared as yet. The system strength issue in Victoria in late 2018 arose when forced generator

outages coincided with a number of planned maintenance outages. While such circumstances do not justify the immediate declaration of a shortfall, a shift towards a greater proportion of asynchronous generation is likely to ultimately require the declaration of a shortfall at some point in time.

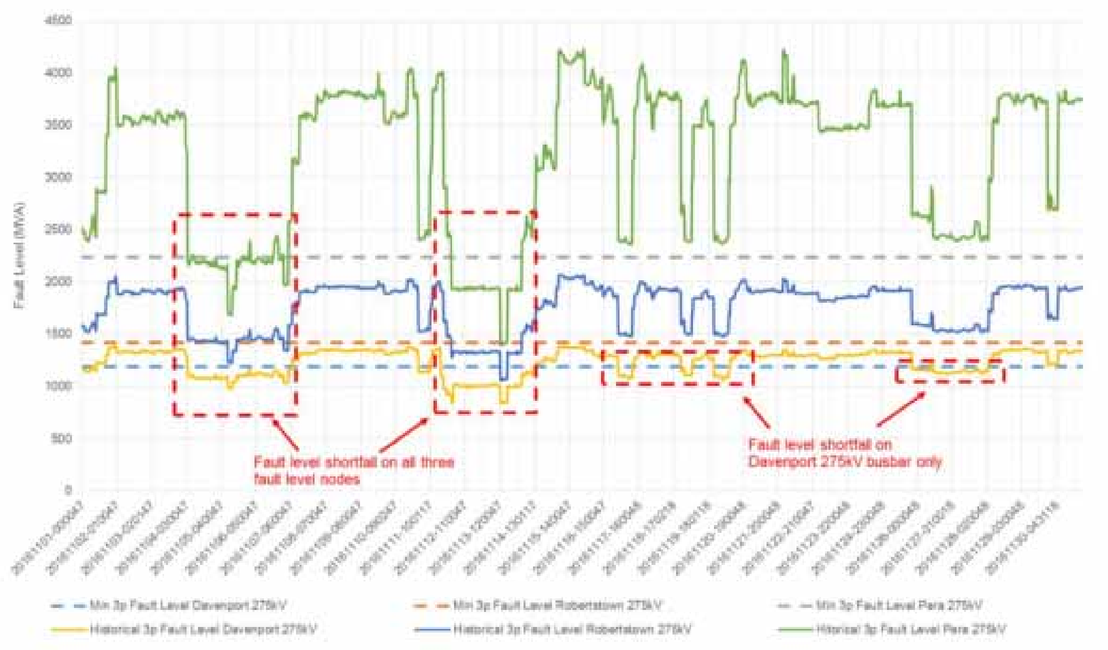
7.2.3 System strength varies over time

When considering the extent of system strength issues, it is important to note that the magnitude of system strength issues vary over time. The issues will differ between regions and potentially also seasons as the dispatch patterns of synchronous generation change.

Where AEMO has declared a shortfall, the shortfall is not always physically present. The actual physical shortfall in the power system at any given time will depend on the contributions to system strength made by the generators in the dispatched generation mix. The variability in system strength is shown in Figure 7.3.. The figure shows the fault level in South Australia over the course of November 2016, prior to the first system strength direction being issued in April 2017.

- The green line shows the fault level at the Para 275kV fault node. The grey dotted line is the required fault level at that fault level node (determined in mid 2018 in accordance with the minimum system strength framework).
- The blue line shows the fault level at the Robertstown 275kV fault node. The orange dotted line is the required fault level at that fault level node.
- The yellow line shows the fault level at the Davenport 275kV fault node. The light blue dotted line is the required fault level at that fault level node.

Figure 7.3: Varying fault levels in South Australia compared to the minimum required levels specified by AEMO



Source: AEMO, *System strength requirements methodology,* p. 23.

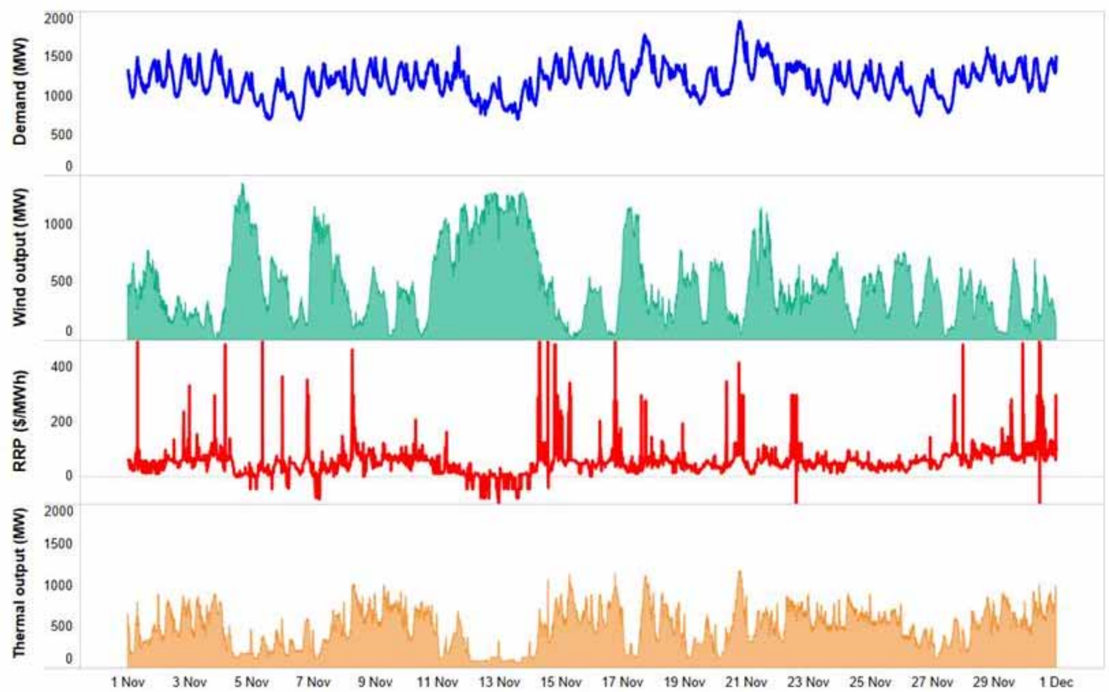
Figure 7.3 shows that system strength has, at times, fallen below the level required for the secure operation of the South Australian power system. In particular, in the period 4 -7 November, and again in the period 11 - 14 November, system strength fell below minimum levels at all three nodes for a total of 7 days. Later in the month, system strength fell below minimum levels at the Davenport node for a total of 6 days. (Davenport has a high concentration of asynchronous generation and is electrically remote from synchronous generation centres so system strength is lower there.)

As shown in figure 7.3 below, the first two periods of low system strength in early and mid November (which affected all three nodes) were driven by low demand coupled with high output from wind farms. This in turn led to prices falling to negative levels and a significant amount of synchronous thermal generation withdrawing from the market. (Such an outcome would not occur now: instead, AEMO would direct synchronous generators to remain online in order to maintain adequate system strength.)

Fault levels fell to their lowest levels on 13 November 2016 when, for over five hours, only one synchronous generating unit was operating in South Australia. Demand at the time was moderate, supply was predominantly from wind and the spot price was negative. While no power system analysis tools indicated the system was insecure at the time, later analysis demonstrated that fault levels were so low that the system, while in a satisfactory state, was not in a secure state. If the single operating generating unit had tripped, other generators may have disconnected from the system, protection systems may have failed, and voltage changes may have become excessive. Following this reviewable incident, AEMO instituted a requirement that two sycnhronous generating units be online at all times to keep the system secure.[311] Subsequent modelling has further refined this approach.[312]

The combination of high wind output and low demand puts significant downward pressure on the South Australian spot price, and impacts the ability of synchronous generators to recover their short run costs (SRMC). As gas fired generators are able to vary output or shut down more readily than coal-fired generators, they are more likely than coal-fired plant (particularly brown coal plant) to reduce output or withdraw from the market in response to low prices, thereby creating system strength shortfalls which need to be addressed through directions (or TNSP contracting). As more low to zero SRMC generation connects to the power system, this price trend can be expected to continue with important implications for what 'typical dispatch patterns' will look like going forward, both in South Australia and other regions. (This is discussed further below in section 7.4.2.)

Figure 7.4: Factors influencing system strength in November 2016: demand, wind output, price and thermal output



Source: AEMC analysis

Note: The vertical axis for prices is limited to a range of -$100 to $500 so that low prices (coinciding with periods of high wind output) are discernible.

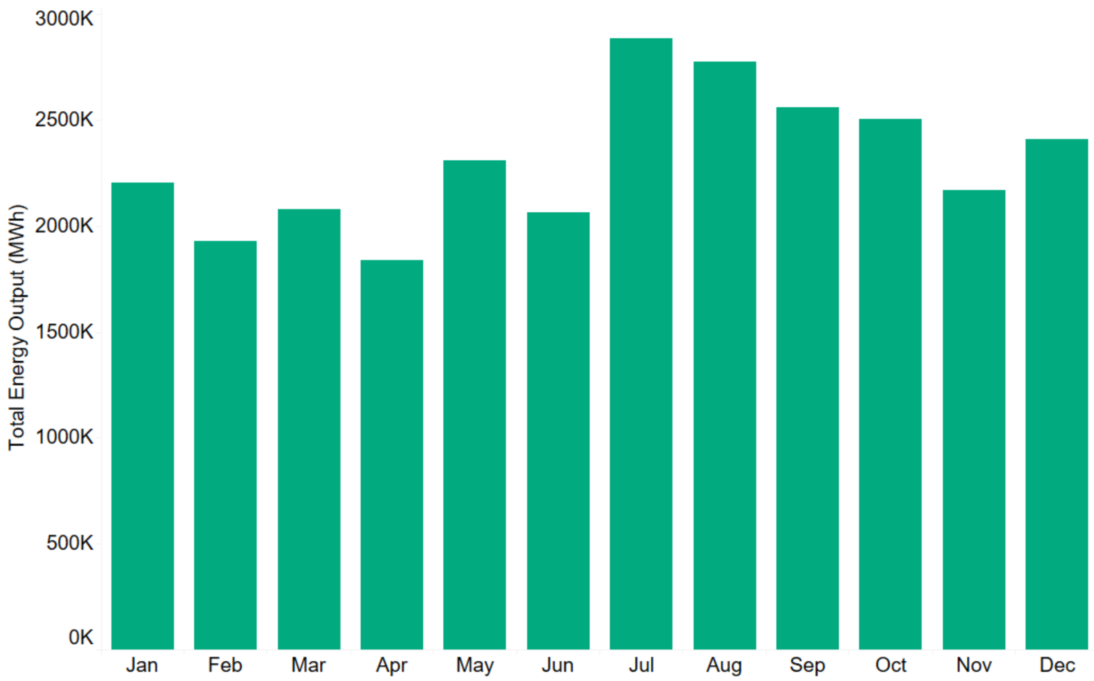
311 AEMO, *Power system not in a secure operating state in South Australia on 13 November 2016*, April 2017.

312 AEMO, *Transfer limit advice - South Australia system strength*, December 2018

While the above figures (7.3 and 7.4) demonstrate the variability in levels of system strength over a month, there also appear to be broader trends in the provision of system strength over weeks or months of the year when typical generator dispatch patterns result in fault levels consistently falling below the required levels.

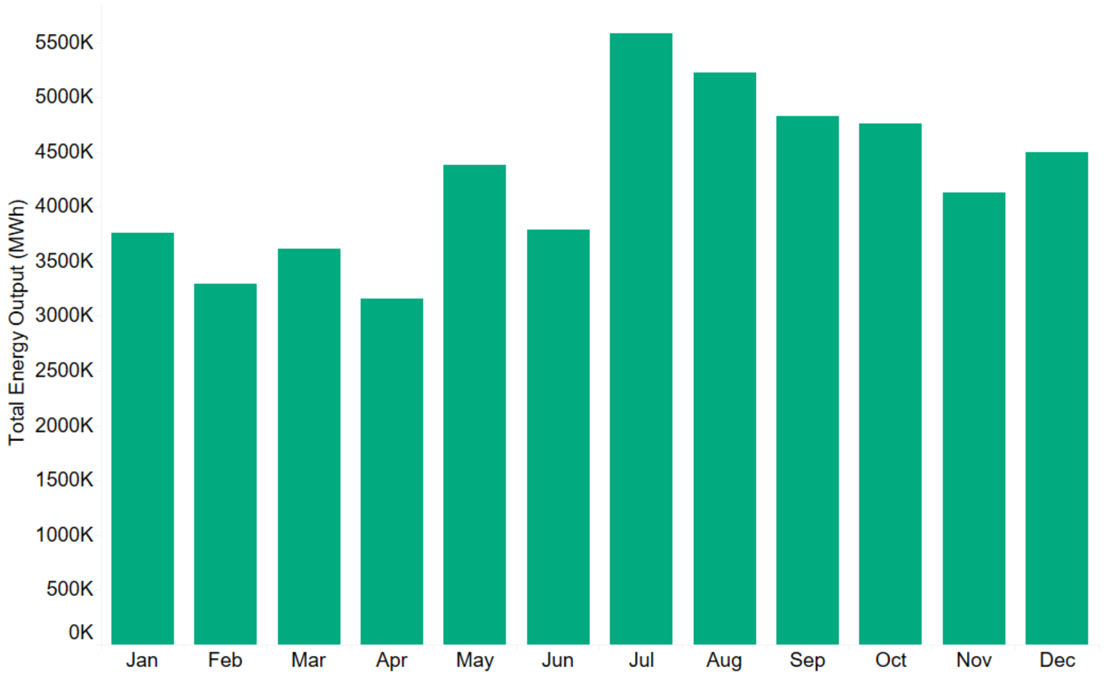
Wind output is seasonal and is highest in winter. Figure 7.5 below shows monthly wind output in South Australia in the period 2010 to 2018, while figure 7.6 shows monthly wind output across the NEM during the same period.

Figure 7.5: SA wind output by month, 2010 to 2018



Source: AEMC analysis

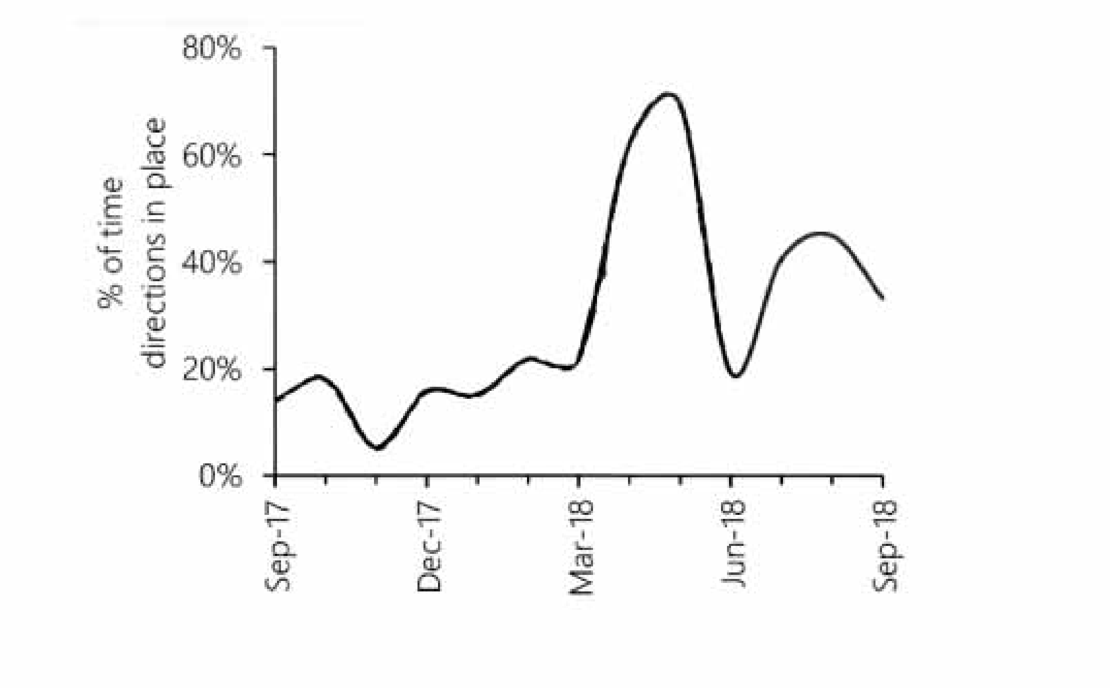
Figure 7.6: NEM-wide wind output by month, 2010 to 2018



Source: AEMC analysis

The variation in the magnitude of actual system strength shortfalls in South Australia during 2018 is reflected in the frequency of directions issued to synchronous generators in the region. Figure 7.7 shows that over the period September 2017 to September 2018, more directions were issued during the shoulder seasons indicating a potentially greater shortfall at these times. However, it also demonstrates that directions are issued in South Australia at all times of the year. In addition, this does not necessarily indicate that system strength shortfalls are more likely to be present, or be more prominent, during shoulder seasons in future years. (See futher data in figure 7.11.)

Figure 7.7: Frequency of directions in South Australia



Source: AEMO, *Quarterly Energy Dynamics, Q3 2018*, p. 7.

7.3 Application of minimum system strength framework

The minimum system strength framework has been in place since 1 July 2018. (However the framework came into effect on 13 October 2017 in South Australia under the transitional arrangements.) On 1 July 2018, AEMO published:[313]

- the system strength impact assessment guidelines - guidelines that assist NSPs in assessing the extent of any adverse system strength impact caused by a new connecting generator.
- the system strength requirements methodology - the methodology with which AEMO determines the minimum level of system strength required for each region.
- the system strength requirements for each region - the minimum level of system strength required at fault level nodes in each region.
- notices of any system strength shortfalls - a notice that the level of system strength typically provided in a region, or expected to be typically provided, is less than the required level, resulting in a shortfall.

313 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review

These documents were published alongside the corresponding publications for the minimum inertia framework established under the *Managing the rate of change of power system frequency* final rule.[314]

The table below summarises the fault level requirements for each region, at the specified fault level nodes.

Table 7.2: Fault level nodes and minimum three phase fault levels for 2018

REGION	LOCATION OF FAULT LEVEL NODE	MINIMUM THREE PHASE FAULT LEVEL (MVA)
South Australia	Davenport 275 kV	1150
	Robertstown 275 kV	1400
	Para 275 kV	2200
Tasmania	George Town 220 kV	1450
	Waddamana 220 kV	1400
	Burnie 110k kV	750
	Risdon 110 kV	1330
Queensland	Western Downs 275 kV	2550
	Greenbank 275 kV	3800
	Nebo 275 kV	1750
	Gin Gin 275 kV	2400
	Lilyvale 132 kV	1100
New South Wales	Armidale 132 kV	3000
	Sydney West 330 kV	9250
	Wellington 330 kV	1900
	Newcastle 330 kV	8400
	Darlington Point 330 kV	1550
Victoria	Hazelwood 500 kV	8850
	Dederang 220 kV	3500
	Thomastown 220 kV	4100
	Red Cliffs 220 kV	600
	Moorabool 220 kV	4400

Source: AEMO, *System strength requirements methodology,* p.3.

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

In addition to declaring the minimum required fault levels for each region, AEMO is also required to declare any fault level shortfalls. At 1 July 2018, AEMO declared that the only region with a fault level shortfall was South Australia.[315] The indicative three-phase fault level required to meet this shortfall in South Australia is 620 MVA as measured at Davenport 275 kV fault level node.[316]

7.3.1 Addressing emerging system strength issues under the minimum system strength framework

Figure 7.8 shows how the minimum system strength framework addresses system strength issues as they emerge.

- Initially, insufficient system strength is considered unlikely to occur and no shortfall is declared. However, it is possible that under certain circumstances system strength issues will arise that will need to be managed by AEMO. AEMO currently does so by directing generators. These issues may occur under extenuating circumstances, such as when a number of synchronous generating units are out of service for maintenance and one or more forced outages occur on other synchronous generating units. (This was the situation in Victoria in November 2018.) Over time, these issues could also start to occur when high levels of asynchronous generation output coincide with periods of low to moderate demand, resulting in low spot prices and synchronous generators bidding unavailable for commercial reasons. (This was the situation in South Australia in November 2016, as illustrated in figure 7.3.)
- At some point in time, when AEMO considers that the level of system strength typically provided by generators is no longer sufficient to maintain a secure power system, it will declare a shortfall in system strength (fault level shortfall). The relevant TNSP is then required to make up the shortfall in accordance with the minimum system strength framework. When a TNSP is required to meet a shortfall, it must take into account planned outages, the risk of unplanned outages and the impact of any procured system strength services on typical dispatch patterns.[317] Despite this, there is always a risk that further unexpected outages may occur which give rise to system strength related issues. Therefore, even when a shortfall has been declared,circumstances may still arise at times, which require AEMO to issue directions to address system strength issues.
- As the generation mix continues to change, the size of the shortfall declared will increase and the TNSP will be required to provide for greater levels of system strength and AEMO will continue to need to maintain system security. System strength shortfalls can be expected to increase as existing synchronous generators retire and as installation of residential scale solar continues to grow (residential solar both reduces operational demand - with impacts on spot prices and the viability of synchronous generators - and increases the need for system strength). By contrast, the connection of new large scale generators with low to zero cost SRMC would not be expected to directly impact the size of the shortfall given the “do no harm” obligations. However, the growing market share of

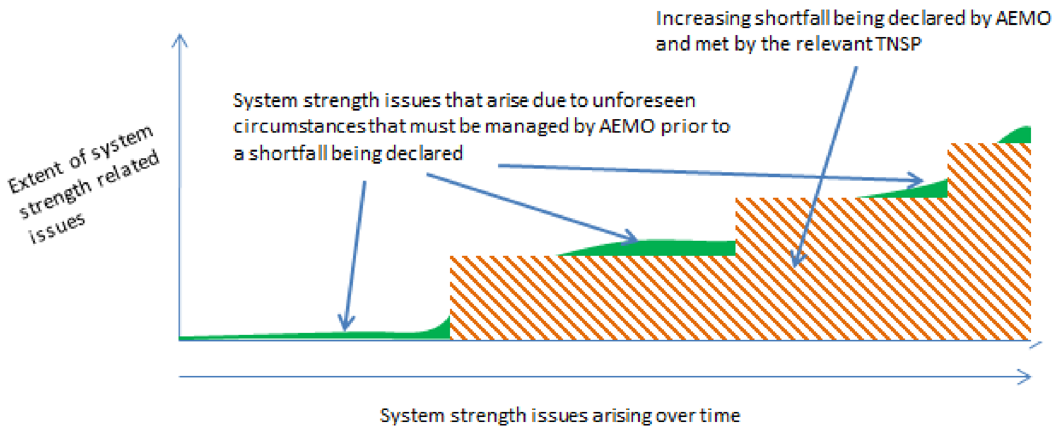
315 AEMO, *System strength requirements methodology*, p. 4.

316 AEMO, *Second update to the 2016 national transmission network development plan,* October 2017.

317 NER Clause 5.20C.3(c)(2).

such generators can be expected to indirectly impact the shortfall by displacing synchronous generators in the merit order.

Figure 7.8: Managing system strength issues as they emerge



7.3.2 Declaring future shortfalls

AEMO's *System Strength Requirements Methodology*[318] was published in July 2018. It sets out how AEMO determined the minimum three phase fault levels in each region (also published on 1 July 2018) and how AEMO determined whether any region faced a fault level shortfall. (The only region found by AEMO to be subject to a shortfall as at 1 July 2018 was South Australia.)

Given the limited time in which to prepare the methodology and undertake the analysis, the methodology notes that "the determination of three phase fault levels as at 1 July 2018 only considered the state of the current power system".[319] AEMO has indicated that it intends to update the methodology in late 2019 or early 2020 in order to adopt a more forward-looking approach. This is consistent with the requirements under clause 5.20.2(c)(14) of the NER for AEMO to forecast any fault level shortfalls arising at any time within a planning horizon of at least five years. The NER also require this to be subject to consultation in accordance with the Rules consultation procedures. (The initial methodology was exempt from this requirement given the limited time available.)

The initial methodology's approach to determining minimum fault levels and identifying any shortfall is described below. It includes two assessment stages, starting with a relatively simplified analysis using static fault current calculations and progressing to more detailed analysis if warranted based on the outcomes of the first stage analysis.[320]

Stage 1 assessment:

318 AEMO, *System strength requirements methodology: system strength requirements and fault level shortfalls,* June 2018

319 AEMO, *System Strength Requirements Methodology*, July 2018, p. 18.

320 AEMO, *System strength requirements methodology*, pp. 16 - 20.

- This first stage establishes a benchmark dispatch pattern (known as the "minimum synchronous machine dispatch scenario") which is used to identify whether a region is at risk of a fault level shortfall, and for comparison with later years. These scenarios were developed for each region (other than South Australia, where a shortfall has already been declared and stage 2 analysis was already complete) by AEMO in consultation with a working group including TNSPs. Each scenario was designed to meet power system stability and system standard assessment criteria, accounting for the possible outage of the largest synchronous machine or transmission element in the region. In particular, each scenario was required to comply with Australian standards relating to voltage step change limits, provide positive available fault level at the connection points of existing asynchronous generators (indicating the likelihood of asynchronous generation to ride through faults), and allow protection systems to operate correctly. The scenario was also required to enable protection systems to operate correctly even when the region is 'islanded' from the remainder of the NEM.
- The minimum three phase fault levels at each fault level node were determined based on these dispatch scenarios for each region other than South Australia for 2018. (For South Australia, minimum three phase fault levels were established using a stage 2 assessment.) These will be used as a benchmark against which to compare changes to system strength levels in subsequent years.
- AEMO compares the calculated three phase fault levels at the fault level nodes, produced by actual synchronous generators' dispatch patterns over the previous two years with the minimum three phase fault levels to identify whether actual fault levels are approaching or falling below the minimum required levels.
- If the system strength provided by actual dispatch patterns meets the minimum required level of system strength, no shortfall is expected to occur. If the assessment indicates that actual dispatch patterns could result in a fault level shortfall, AEMO will progress to a second stage assessment. A second stage assessment will also be triggered if, in any subsequent year, analysis shows that minimum fault levels cannot be maintained by the "typical synchronous machine dispatch pattern". As AEMO notes in the methodology, "such a gap might be caused by synchronous machine retirement or displacement due to increased asynchronous generation penetration" (p. 18).

Stage 2 assessment:

- The second stage assessment involves a more detailed power system study to confirm the minimum acceptable synchronous machine dispatch scenarios that can provide sufficient system strength. The dispatch scenarios derived from the stage 2 assessment are then used to determine the minimum three phase fault levels at the fault level nodes.
- Once the minimum fault levels have been determined based on this more detailed analysis, AEMO assesses whether a shortfall exists. The fault level shortfall is quantified by comparing the fault levels produced by the minimum acceptable synchronous machine dispatch scenario and the fault levels produced by "typical dispatch patterns".

- It follows the same approach as was used for the South Australia System Strength Assessment.[321]

This approach is discussed further in section 7.4.2.

7.4 Issues for stakeholder consultation

7.4.1 Rationale for raising the framework for consultation

Since the establishment of the minimum system strength framework, system strength related issues have become increasingly prevalent. This is particularly the case in the South Australian power system. The Commission notes that the minimum system strength framework has been in effect in South Australia since November 2017, and in other regions since July 2018, but to date AEMO has not declared a shortfall in either system strength or inertia outside of South Australia. However, the continued trend toward asynchronous generation suggests that shortfalls in other NEM regions are likely to emerge in the future.

More recently, AEMO has needed to issue one direction to a generator in Victoria in order to maintain adequate system strength.[322] More information on these directions is provided in Box 3 in section 7.2.2. This may indicate the emergence of system strength related issues outside of South Australia.

As such, the Commission intends to explore whether adjustments could be made to these frameworks to improve the flexibility with which they can be applied to address issues as they begin to emerge in other NEM regions. A more flexible framework may limit the need for the use of directions and interventions pricing, which can have unintended impacts on the wholesale price and investment signals.

As part of the *Integrated system plan* published in July 2018, AEMO has undertaken an assessment of system strength and has found that, in addition to South Australia, there are low levels of system strength at the fringes of the grid, particularly in north Queensland, south-west New South Wales, and north-western Victoria.[323]The system strength in these areas is low due to the relative lack of synchronous generation, and the development of asynchronous generation, such as wind and solar.

The 2018 National Transmission Network Development Plan (NTNDP) builds on the ISP analysis and states that "low system strength in many other areas of the network [other than South Australia] will affect asynchronous generation connections, potentially requiring existing asynchronous generation to be heavily constrained during planned outages. New asynchronous generator connections in weak areas of the grid are highly likely to be required to incorporate system strength remediation in their projects."[324]

321 AEMO, *South Australia System Strength Assessment*, September 2017

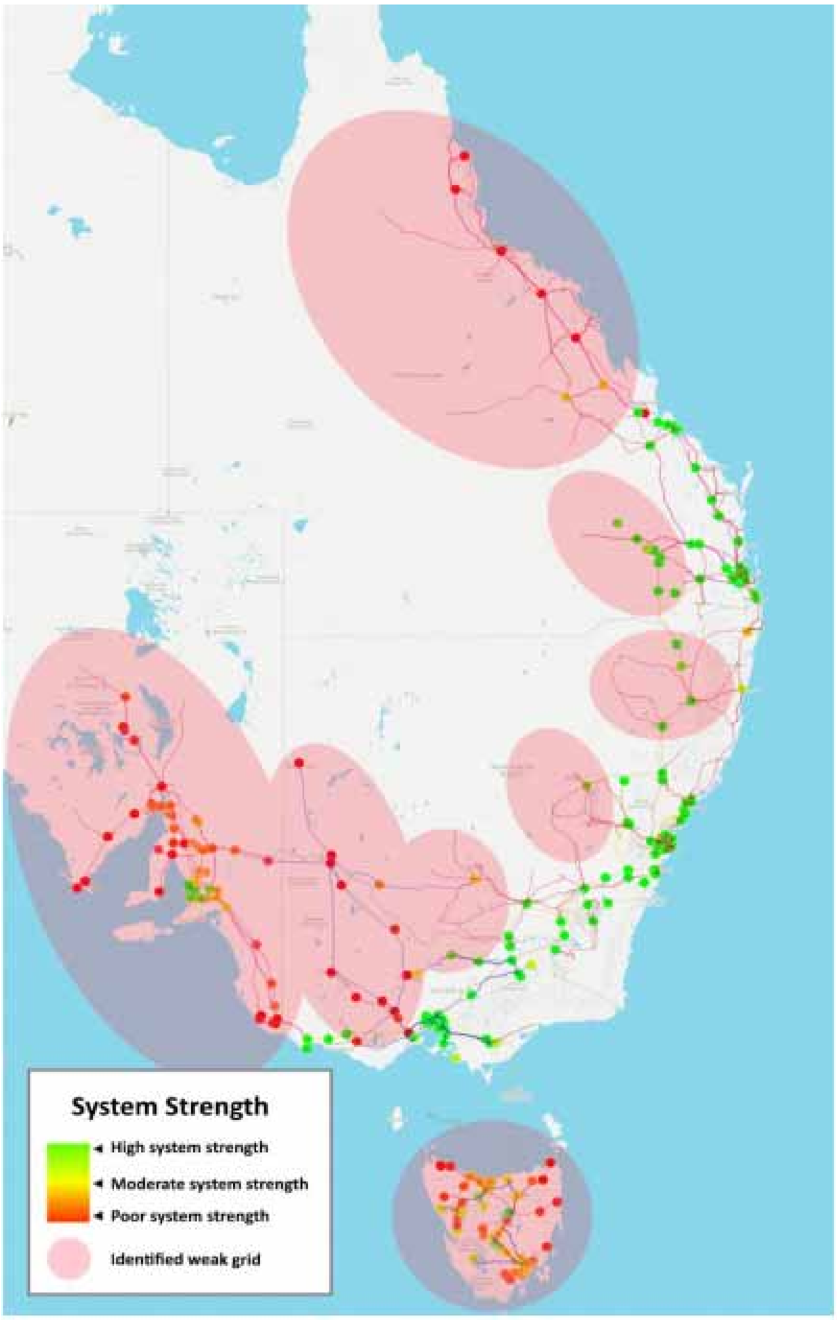
322 Directions were issued to participants in Victoria on 16, 17 and 18 November 2018. These directions were to manage post-contingent voltage levels (16 and 18 November) and system strength (17 November).

323 AEMO, *Integrated system plan*, July 2018, pp. 72 - 73.

324 AEMO, *National Transmission Network Development Plan*, December 2018, p. 12. The potential for greater coordination of investment in remediation works is recognised as an issue in the *Integrated System Plan* (p. 73) and the consultation paper on COGATI Implementation: AEMC, *Consultation paper: COGATI implementation - access and charging*, March 2019, p. 10.

Figure 7.9 below highlights those areas where existing asynchronous generation output may need to be curtailed during planned outages of synchronous plant to manage the risks created by low fault current levels.

Figure 7.9: Identified and emerging weak grid areas



Source: AEMO, *National transmission network development plan*, December 2018, p. 17

Note: Note that some areas with high system strength are flagged as emerging weak grid areas due to high levels of asynchronous generator connection interest.

In relation to Victoria, the NTNDP notes that "during system normal, the Victorian grid typically meets the minimum system strength requirements at the defined fault level nodes. ISP projections show that the expected minimum number of synchronous units online already reaches the minimum operating requirement. AEMO is currently conducting detailed studies to review and refine the minimum requirement, and to consider how this requirement is impacted when 500 kV lines are switched out of service for voltage control purposes."[325]

In relation to NSW, the NTNDP notes that "following the closure of Liddell Power Station in late 2022, the ISP projects that while the minimum regional fault level requirements continue to be met, the expected minimum number of synchronous units online could reach the minimum operating requirement. Further detailed studies into the projected minimum dispatch generation scenarios and minimum fault level requirements for New South Wales will be undertaken by AEMO through 2019, to firm up projected requirements and options needed to manage the power system following the closure of Liddell Power Station."[326]

With respect to inertia, the NTNDP notes that - in addition to the inertia shortfall declared in South Australia - inertia levels in Victoria are projected, at times, to be lower than the secure operating level. By 2023-24, typical inertia levels in Victoria are projected to be below the minimum level required (14,700 MWs compared to a required level of 15,400 MWs). However, a shortfall has not been declared in Victoria given the low risk of Victoria being "islanded" from the rest of the NEM.[327]

In light of these issues, the Commission is taking the opportunity to seek stakeholder feedback on the minimum system strength and inertia frameworks with the intention of making them as effective and efficient as possible. The application of these frameworks should obviate the need for AEMO to maintain system security by intervening in the operation of the market. However, the Commission intends to explore whether adjustments could be made to these frameworks to improve the flexibility with which they can be applied to address issues as they begin to emerge in other NEM regions. A more flexible framework may limit the need for the use of directions and interventions pricing, which can have unintended impacts on the wholesale price and investment signals.

7.4.2 Aspects of the framework for consideration

In this paper, the Commission is exploring the flexibility of the minimum system strength and inertia frameworks. The Commission is particularly interested in how well the frameworks accommodate emerging system strength and inertia related issues where there may be a risk of a shortfall occurring but only for a certain time of the year or only under certain circumstances, or where conditions in the power system suddenly change such that a shortfall in system strength is declared which needs to be addressed.

Aspects of the framework that are explored in more detail below include:

325 AEMO, NTNDP 2018, p. 18.

326 ibid.

327 ibid.

- The approach used to determine when and to what extent a fault level shortfall may be expected to arise. In particular, how AEMO should determine what 'typical' dispatch patterns look like over a five-year period in a sector that is undergoing rapid transition.
- The timeframes in the system strength framework for addressing system strength issues. The framework provides TNSPs with at least 12 months to develop and implement the least-cost solution for meeting a shortfall. This timeframe could be adjusted if it would lead to better overall outcomes. Alternatively, the framework could provide for an interim solution prior to TNSPs addressing the system strength shortfall.
- The flexibility afforded to AEMO in declaring the nature and extent of a system strength shortfall. The framework accommodates AEMO declaring a system strength shortfall that varies over a year to reflect any seasonal variation that may be resulting in a system strength shortfall. However, declaring shortfalls with a yearly profile may introduce significant additional complexity with limited benefits for consumers.
- Allowing TNSPs more flexibility in how they meet the system strength shortfall. It may be beneficial for the minimum system strength framework to allow a TNSP to meet part of a shortfall or to meet it for part of the time. In addition, there may be benefit in reducing the circumstances a TNSP has to account for when making system strength services available. For example, under the current arrangements, a TNSP must make system strength services available, accounting for planned and unplanned outages. It may be more appropriate and cost effective for system strength issues arising from unplanned outages to be addressed through AEMO's directions power.

These issues are discussed in more detail below.

Typical dispatch patterns and potential fault level shortfalls

Clause 5.20C.2 of the NER requires AEMO, following the determination of a region's minimum three phase fault levels, to assess:

- what fault levels are typically provided at each node in the region, "having regard to typical patterns of dispatched generation" (which includes scheduled and semi-scheduled generation)
- whether there is or is likely to be a fault level shortfall in the region and AEMO's forecast of the period over which the fault level shortfall will exist

In making this assessment, clause 5.20C.2 (b)(1) requires AEMO to take into account "over what time period and to what extent the three phase fault levels at fault level nodes that are typically observed in the region are likely to be insufficient to maintain the power system in a secure operating state". Clause 5.20.2(c)(14) requires that the NTNDP detail AEMO's assessment of any fault level (or inertia) shortfall "arising at any time within a planning horizon of at least 5 years".

AEMO's System strength requirements methodology states that, for the system strength requirements to be published in the 2019 NTNDP and subsequent years, the stage 1 assessment will be conducted within a planning horizon of five years (whereas the approach adopted in determining the 2018 requirements considered only the state of the current power system).[328]

However, it notes that the synchronous machine dispatch scenarios over the five-year period will be assumed to be the same as per the first year in the planning horizon, minus any synchronous machines that are expected to retire over the period. [329] The methodology also notes that "the stage 2 assessment can only be used to confirm the existence and extent of a fault level shortfall in a region covering a timeframe of up to two years only. This is because of the uncertainty of generation connections within a five-year timeframe". AEMO notes that this uncertainty will require extensive assumptions to be applied in the power system models and that this makes the stage 2 assessment "an unreliable and unnecessarily complex indicator of potential fault level shortfalls for the entire five-year planning horizon".[330]

The Commission recognises that there is significant complexity in determining future system strength shortfalls in accordance with the minimum system strength framework. Doing so requires forming expectations of the level of system strength that would "naturally" be provided by the market (that is, without AEMO intervention), and the level that would be required to achieve system security, up to five years into the future. Determining what "typical" dispatch patterns will look like in five years time, particularly in a sector undergoing rapid transformation, is a significant challenge. Doing so involves predicting synchronous generation dispatch patterns which are influenced by a number of variables, including the increasing penetration of low SRMC renewables, reductions in demand, changing wholesale prices, fuel availability and cost.

The Commission also recognises the tension that exists between, on the one hand, the need to identify a potential shortfall up to five years in advance (which requires a higher level view of trends) and, on the other, the detailed analysis required by AEMO (and a TNSP in turn) as to what measures are needed to address any shortfall identified. Appropriately, the Stage 2 assessment approach used in South Australia focuses on what generator combinations can ensure the system remains secure. This is appropriate given that a system strength shortfall has already arisen in that region and that synchronous condensers are yet to be procured and commissioned. However, as AEMO has noted, the Stage 2 assessment is not suited to the task of projecting out five years to identify whether a shortfall is likely to arise in a given region.

While the Commission recognises these challenges, it also notes the importance of identifying potential shortfalls early enough that least cost measures to address the shortfall can be implemented in time under the minimum system strength framework, thereby reducing or avoiding the need to rely on more costly options or market interventions to maintain system security. The Commission notes that, in the case of South Australia, the first indication of the shortfall was included in the 2016 NTNDP and confirmed in late 2017 (after several system strength directions had already been issued). There was insufficient time for ElectraNet to

328 AEMO, *System strength requirements methodology*, July 2018, p. 19.

329 ibid. The Commission considers that the retirement of synchronous generators is a factor that will have a bearing on the timing and extent of any potential shortfall, more so than on the minimum fault levels required to keep the system secure.

330 AEMO, *System strength requirements methodology,* p. 21.

implement network solutions by the due date of 30 March 2018 and the only option available to it was the costly option of generator contracting. ElectraNet's recent economic evaluation report notes that a full solution to address the declared system strength gap will not be in place until the end of 2020.[331]

While identifying a shortfall earlier may entail a lower degree of confidence as to the precise timing and scale of the shortfall, this disbenefit may be offset in part or in whole by the value of having an efficient solution in place before the shortfall materialises. The risk of asset stranding in such cases is likely to be low given that the overall trend is for system strength to continue to decline, reflecting the sustained reduction in operational demand and ongoing growth in the market share of asyhcnronous generation.

Under clause 5.20C.2(a)(2), AEMO is required to determine whether a shortfall exists or is *likely* to arise. This does not require AEMO to form a definitive view that a shortfall *will* arise. However, if AEMO assesses that there is or is likely to be a shortfall in a region, it must publish and give to the TNSP a notice specifying the extent of the shortfall and the date by which the TNSP must procure system strength services to address the shortfall. This does require AEMO to form a view about what is required in response to the actual or anticipated shortfall. This creates the tension noted earlier between the need to form a mid term view about whether/when a shortfall is likely to arise and the need for some degree of specificity about what is required to address the shortfall.

It may be that consideration should be given to developing a process that enables earlier identification of shortfalls, even if this means reducing the degree of specificity as to what is required to address the shortfall. In the case of South Australia, detailed and resource intensive power system computer aided design (PSCAD) modelling has been undertaken to identify the generator combinations that underpin the current AEMO directions to ensure adequate system strength. However, the option being implemented by ElectraNet is the installation of synchronous condensers, rather than generator contracting.

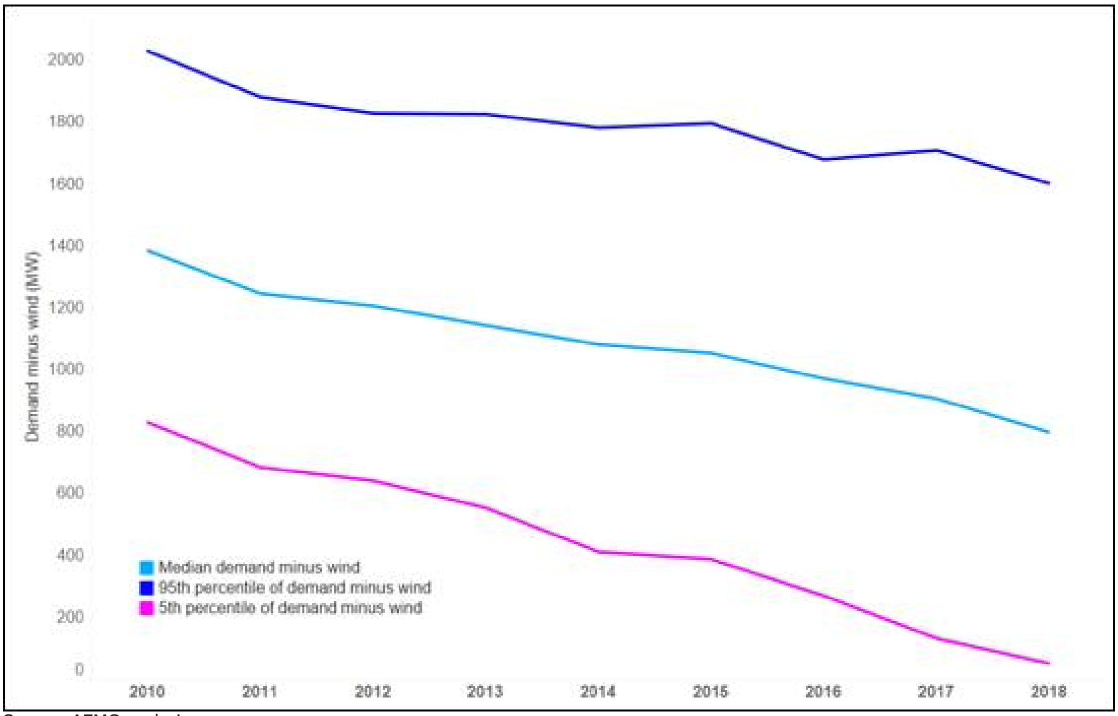
There may be value in undertaking higher level, less detailed analysis to, in the first instance, identify a potential shortfall and, secondly, to identify the nature and scale of the required response. There may be merit in adopting a staged approach whereby a preliminary notice informs the TNSP and market of the potential shortfall, followed by a more detailed notice once further information is available as to the extent of the shortfall and the scale of response required. This could facilitate more timely identification and scoping of possible options by the TNSP in conjunction with AEMO.

What factors underpin 'typical' dispatch patterns?

Experience in South Australia indicates there are two countervailing factors that have a bearing on how 'typical' dispatch patterns can be expected to change over time. These factors are falling operational demand and rising levels of low SRMC asynchronous capacity. Together, they are reducing the amount of 'room' in the merit order that is available to synchronous generation, thereby lowering fault current levels. The impact of these factors on demand for synchronous generation is illustrated in figures 7.10 and 7.11 below.

331 ElectraNet, *Addressing the system strength gap in SA,* February 2019, p. 31.

Figure 7.10: Impact of wind and demand on role of synchronous generation in SA 2010-2018



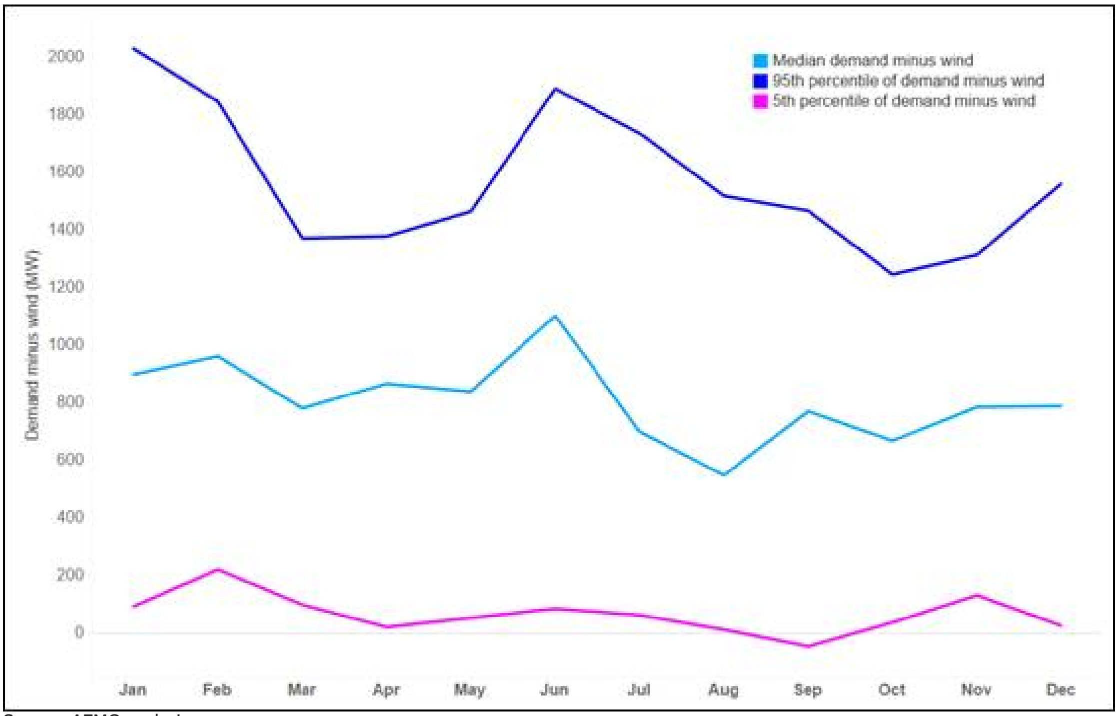
Source: AEMC analysis

Figure 7.10 shows the median, 95th percentile, and 5th percentile of demand for scheduled generation in South Australia on an annual basis from 2010 to 2018. Demand for scheduled generation is defined here as total demand minus the output of all semi-scheduled wind farms in the region.[332]

The figure shows the slow yet inexorable decline of demand for scheduled generation, driven by the entry of wind farms. By including the 5th and 95th percentiles, we can see the change not only in the median, but also in the range of outcomes. The 5th percentile series (shown in pink) shows that there are now regularly periods in South Australia where there is virtually no demand for scheduled (synchronous) generation once we account for the output of wind.

332 The 95th percentile indicates that demand minus wind was equal to or below this level for 95 per cent of the time, while the 5th percentile indicates that demand minus wind was equal to or below this level for 5 per cent of the time.

Figure 7.11: Impact of wind and demand on role of synchronous generation in SA in 2018



Source: AEMC analysis

Figure 7.11 again shows the median, 95th percentile, and 5th percentile of demand for scheduled generation in South Australia, on a monthly basis for 2018 alone. The chart – in particular the series shown in pink – shows that for around 5 per cent of the time demand for scheduled generation is close to, or even below, zero. At times when demand minus wind is less than zero, South Australia will be exporting energy to other regions. This reflects that, in addition to the level of wind energy being delivered to the market, AEMO directs gas generators to operate at such times in order to maintain adequate system strength.

This results in increased electricity exports. As noted in Chapter 4, AEMO's *South Australian Electricity Report* states that 'generation in South Australia increased 27% in 2017-18 to 14,186 GWh, about half supplied from gas-powered generation (GPG). The extra generation was used to meet local demand and exported to Victoria, with 2017-18 being the first time in at least nine years that South Australia was a net exporter of energy'.[333]

The trends shown in this chart are inversely correlated with the frequency of system strength directions issued in South Australia during 2018 (refer figure 7.7+). That is, more directions were issued during autumn and spring when demand for scheduled generation was at its lowest. Analysis of trends such as these in other regions could usefully inform AEMO's determination as to whether/when a system strength shortfall is likely to arise, having regard for projected 'typical' dispatch patterns over a five year period.

333 AEMO, *South Australian Electricity Report*, November 2018, p. 4.

In addition to the impact of new large scale renewable capacity and lower operational demand, regard must also be had for the impact of increasing numbers of residential scale photovoltaic (PV) systems. AEMO staff have advised the Commission that, as with the connection of large scale solar and wind capacity, the significant growth in residential PV systems has important implications for system strength. Increased levels of small scale PV can reduce operational demand at certain times of day and thus the amount of generation that needs to be dispatched by AEMO to meet demand. This in turn has implications for the spot price and whether, or to what extent, synchronous generators will bid available.

In addition, because PV systems are connected to the distribution network via inverters, they reduce system strength in the distribution network and, in turn, the transmission network. Unlike utility scale solar installations, however, small scale PV installations are not subject to the "do no harm" provisions within the minimum system strength framework. Given this, increasing installation of PV capacity will need to inform AEMO's assessment of whether and to what extent a region can be expected to experience a system strength shortfall.

AEMO is required to consult on the system strength requirements methodology alongside the NTNDP inputs.[334] This provides stakeholders with the opportunity to provide feedback on the approach AEMO proposes to take to determine the system strength requirements for a region and to identify potential fault level shortfalls. In advance of that consultation process, and to inform AEMO's development of any revised methodology, stakeholders are invited to provide feedback on the approach adopted to date by AEMO and what, if any, changes warrant consideration.

QUESTION 13: APPROACH TO SETTING SYSTEM STRENGTH REQUIREMENTS AND IDENTIFYING SHORTFALLS

1. Do stakeholders have any views about the approach adopted to date by AEMO to determine system strength requirements and identify potential shortfalls?
2. Do stakeholders have any suggestions as to what, if any, changes to the current methodology warrant consideration?
3. How should AEMO identify shortfalls up to five years ahead, and what does this mean for the level of specificity than can be achieved as to what measures are required in response to the shortfall? For example, would there be merit in considering a staged approach whereby a preliminary notice is used to identify a projected shortfall in a timely way, followed by more detailed analysis as to the required response.
4. Do stakeholders have any views about the impact of residential PV systems on system strength?

334 NER Clause 5.20.1(b).

Interaction between short term and long term solutions

Conditions in the power system may unexpectedly change, which may necessitate the declaration of a system strength shortfall. This may occur due to the unexpected and frequent unavailability of certain synchronous generators. In these cases, the issuing of directions by AEMO may be an effective short-term solution to address the shortfall. However, the application of the system strength framework to address the shortfall in a timely and enduring manner would likely represent a more economically efficient solution.

The minimum system strength and inertia frameworks require the TNSP to address the shortfall through the lowest cost option of either constructing new network assets, such as synchronous condensers, or by contracting (potentially longer term) with synchronous generators to operate at certain times. However, the time required to implement these options may not be conducive to addressing emerging system strength issues in a timely manner, particularly if the need to address the system strength shortfall is immediate or arose unexpectedly.

In such cases, the only option may be for AEMO to issue directions to synchronous generators, as it is currently doing in South Australia. However, this approach to managing system strength does not apply an economic framework to provide for a least-cost solution. It also has the potential to distort market price signals, as the interventions pricing framework was not intended to be applied on an ongoing basis to manage power system security.

In developing the minimum system strength framework, a balance was sought between providing sufficient time for the TNSP to determine a least-cost solution while also implementing the solution to address the shortfall quickly. If AEMO determines that there is a system strength shortfall, the TNSP must be afforded at least 12 months to address this shortfall. In order to allow the TNSP time to equally consider and implement network and non-network based solutions, the system strength and inertia rules exempt the TNSP from the requirement to undertake a regulatory investment test for transmission (RIT-T) where the TNSP is required to meet a shortfall in less than 18 months.

Nevertheless, the system strength and inertia frameworks may still provide insufficient time for AEMO to reasonably forecast the extent and timing of a shortfall, or for the relevant TNSP to determine and implement the least cost solution to address the shortfall.[335]

Ultimately, the current arrangements provide for:

- a short term solution to system strength issues through directions, which are not made with long term economic efficiency considerations in mind but can operate flexibly in the short term

335 AEMO's ability to predict shortfalls may be improved by the final rule for *Generator three year notice of closure*. The final rule requires large electricity generators, which include those that make the most significant contributions to system strength and inertia, to provide at least three years' notice to the market before closing. The final rule and determination are available at: https://www.aemc.gov.au/rule-changes/generator-three-year-notice-closure

- a mid to longer term solution through the minimum system strength framework, which should deliver the least cost solution but may not be able to address emerging or harder to forecast short term issues.

In order to achieve the right combination of flexibility and economically prudent long term solutions, the Commission will consider whether these two frameworks operate effectively alongside each other. One issue to consider will be how to determine what constitutes "typical" dispatch patterns when those dispatch patterns have been significantly impacted by AEMO directions to generators, particularly where generators have become "direction dependent" (that is, where generators withdraw from the market and await direction when the spot price falls below the level of compensation that the generator will be paid if directed).

QUESTION 14: INTERACTION BETWEEN SHORT AND LONG TERM SOLUTIONS

1. Do stakeholders have views on the interaction between the minimum system strength framework and the current arrangements of issuing directions?
2. Are there potential interim solutions that could be implemented to effectively deal with system strength issues as they arise in NEM regions?

Declaring shortfalls that vary over time

The existing frameworks require the TNSP to make the minimum level of system strength or inertia continuously available when a shortfall is declared. However, in some cases, the duration of the likely shortfall may be too small to warrant requiring a TNSP to make services continuously available to address the possible shortfall.

For example, AEMO has not declared a shortfall in Victoria but it was required to issue a direction to maintain sufficient system strength. If system strength issues only occur a limited number of times per year in Victoria, the most efficient solution may be to issue a small number of directions to generators at these times, rather than declare a shortfall. However, at some point, the reduction in system strength in the region would necessitate the declaration of a shortfall.

The framework as set out in the NER allows AEMO to declare a shortfall which varies in size over time or exists for certain months or weeks of the year. In the framework, AEMO must take into account:[336]

1. over what time period and to what extent the system strength typically observed in the region is likely to be insufficient to maintain the power system in a secure operating state
2. any other matters that AEMO considers to be relevant in making its assessment.

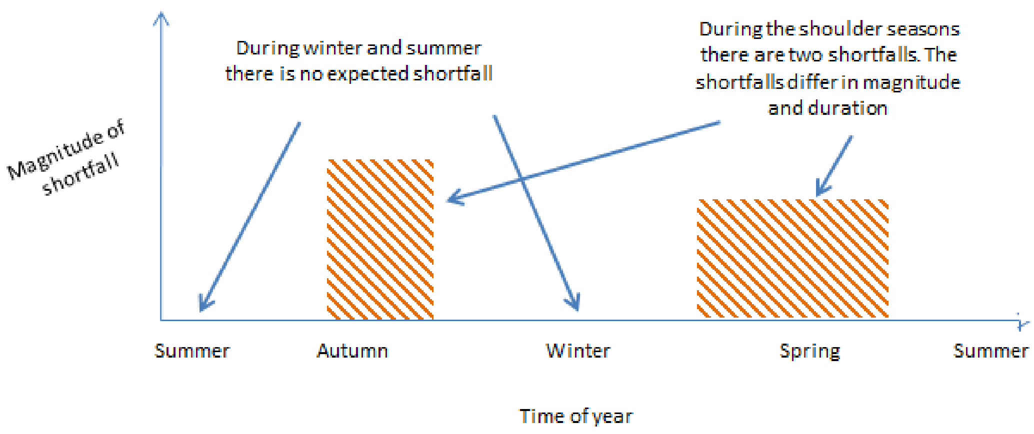
This requirement does not inhibit AEMO's ability to declare a shortfall that varies in magnitude over the year. As such, the minimum framework contains sufficient flexibility to accommodate instances of low system strength varying over time in NEM regions. This may

336 NER Clause 5.20C.2.

also be more economically efficient in NEM regions where system strength issues are emerging as it would only require the TNSP to make system strength services available to the extent and duration that is needed.

For example, if a system strength shortfall was expected to only occur in April and May, a shortfall could be declared only during these months. Figure 7.12 shows an example of a shortfall that could be declared where a shortfall in system strength was only expected to occur during the shoulder seasons.

Figure 7.12: Profiled shortfall



A constant declared shortfall may be preferable for NEM regions where the levels of system strength typically provided to the system are consistently low. In the case of South Australia, a constant shortfall has been declared.[337]

Declaring a shortfall that varies in magnitude over the year may provide a more efficient solution for addressing system strength issues as they emerge throughout the NEM. Issues related to system strength are likely to be first experienced infrequently when significant amounts of synchronous generation are unavailable, either due to planned and/or unplanned outages, or for commercial reasons (e.g. when high wind output and low demand combine to lower spot prices, making it uneconomic for synchronous generators to bid available). This may only occur a few times per year and not constitute a constant shortfall that should be continuously provided year round by a TNSP. However, if these infrequent events are foreseeable they could be addressed by declaring a shortfall for a subset of the year.

If AEMO were to declare a more profiled shortfall, the relevant TNSP could contract with generators to address these limited periods where system strength issues are experienced.

337 This was consistent with the NSCAS gap that was declared by AEMO prior to the publication of the final rule for *Managing power system fault levels*. The transitional arrangements in the final rule allowed AEMO to withdraw the NSCAS gap, and reissue it. AEMO subsequently withdrew the NSCAS gap and reissued it as a constant system strength shortfall after the commencement of the final rule.

This may ultimately result in more efficient solutions to emerging system strength issues. For example, a TNSP could be required to only make up a system strength shortfall in the shoulder seasons, where the amount of system strength provided by generators in the market is typically lower. If a TNSP could do so, it may be a lower cost option for the TNSP to contract with generators for certain times of year, as opposed to procuring system strength services that are continuously available.

However, a shortfall that varies in size over the course of the year, or one that is only declared for certain months of the year, may lead to other inefficiencies. If the shortfall was highly variable over the year, this would leave significant complexity with the TNSP in trying to find the least-cost solution. The varied shortfall may more accurately reflect the nature of the system strength issue but the TNSP would need to enter into contractual arrangements that reflect this variability.

Such an approach could also result in the shortfall moving in time from the period when it was predicted to occur to another period of the year. For example, if TNSP contracting results in a generator delaying its scheduled maintenance to periods outside of the shortfall period (e.g. moving it from autumn to early winter), the result may be to create a new shortfall in another period of the year. This could ultimately create reliability issues if generators are not available during high demand periods.

In addition, there is likely to be significant challenges associated with accurately forecasting the extent of a system strength shortfall. The extent of a shortfall results from the expected dispatch patterns of generators up to five years in the future. The actual dispatch patterns that occur may end up being different as generators respond to market conditions and make decisions relating to unit commitment and maintenance. It is reasonable to expect AEMO's forecasts of system strength shortfalls to vary over time as information is updated. If the shortfall was incorrectly forecast, the TNSP may implement a solution that does not address the system strength issues encountered in real time. AEMO would then need to rely on its direction powers to address system strength issues.

QUESTION 15: DECLARING SHORTFALLS THAT VARY OVER TIME

1. Do stakeholders see any risks or benefits in AEMO declaring a shortfall that varies in magnitude over the year?
2. Do stakeholders consider there to be any potential changes that could be made to the rules to enhance the flexibility of the current arrangements?

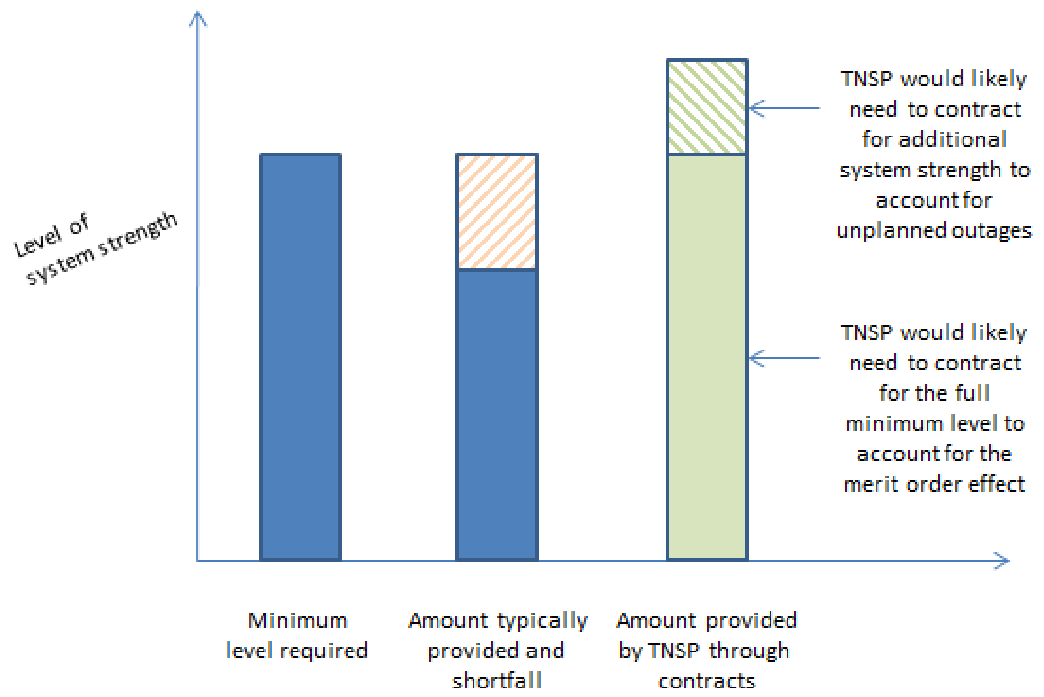
TNSP meeting the shortfall

Under the framework, the relevant TNSP must make a range and level of system strength services available such that it is reasonably likely that these services are continuously available to meet the shortfall (taking into account the risk of unplanned outages, planned outages and the potential for system security services to impact typical patterns of dispatched generation).[338]

If the TNSP elected to build synchronous condensers then, to comply with the framework, it would only need to build a number sufficient to address the size of the shortfall.[339] However, if the TNSP elected to enter into contracts with generators, it would need to make the entire minimum system strength continuously available in the region. This is because any contracts that the TNSP has with synchronous generators to come online to provide system strength are likely to cause other synchronous generators, which are also providing system strength, to be pushed out of the dispatch merit order, potentially resulting in only a small, or no, overall increase in system strength. This merit order effect applies even in circumstances where AEMO has identified only a small shortfall in system strength.

In addition, the TNSP would need to provide for sufficient redundancy in its generator contracts to account for planned and unplanned outages. Ultimately, the TNSP would likely need to contract for a level of system strength above the total minimum level of system strength, as shown in Figure 7.13.

Figure 7.13: Making up a shortfall through contracting



338 NER Clause 5.20C.3(c)(2).

339 AEMO has indicated that ElectraNet has been instructed to supply sufficient fault current at all nodes in South Australia - not just to address the shortfall declared at the Davenport node.

Contracting for redundancy may not deliver the least cost option for addressing system strength issues. TNSPs have limited roles in managing the coordination of generators and, as such, are not fully equipped to efficiently estimate and manage the extent of this risk. This may mean that a TNSP over-contracts for system strength to manage the risks associated with planned and unplanned outages.

The nature of these risks may be better managed through AEMO's directions power which can be used closer to real time. Decisions to direct participants are not made under an economic framework. However, when used infrequently to address extenuating circumstances, directions may be the most effective and efficient option for addressing specific system strength issues.

> QUESTION 16: TNSP MEETING THE SHORTFALL
>
> Do stakeholders have feedback on potential changes that could be made to the minimum system strength framework in order to make it simpler or more cost-effective for the TNSP to address a system strength shortfall?

7.5 Providing more than minimum levels of system strength and inertia

In September 2017, the AEMC introduced frameworks in the NER to require TNSPs to maintain minimum levels of system strength and inertia. The provision of these minimum levels is required if AEMO considers there to be a shortfall in a particular NEM region such that the security of the power system cannot be maintained under typical operating conditions.

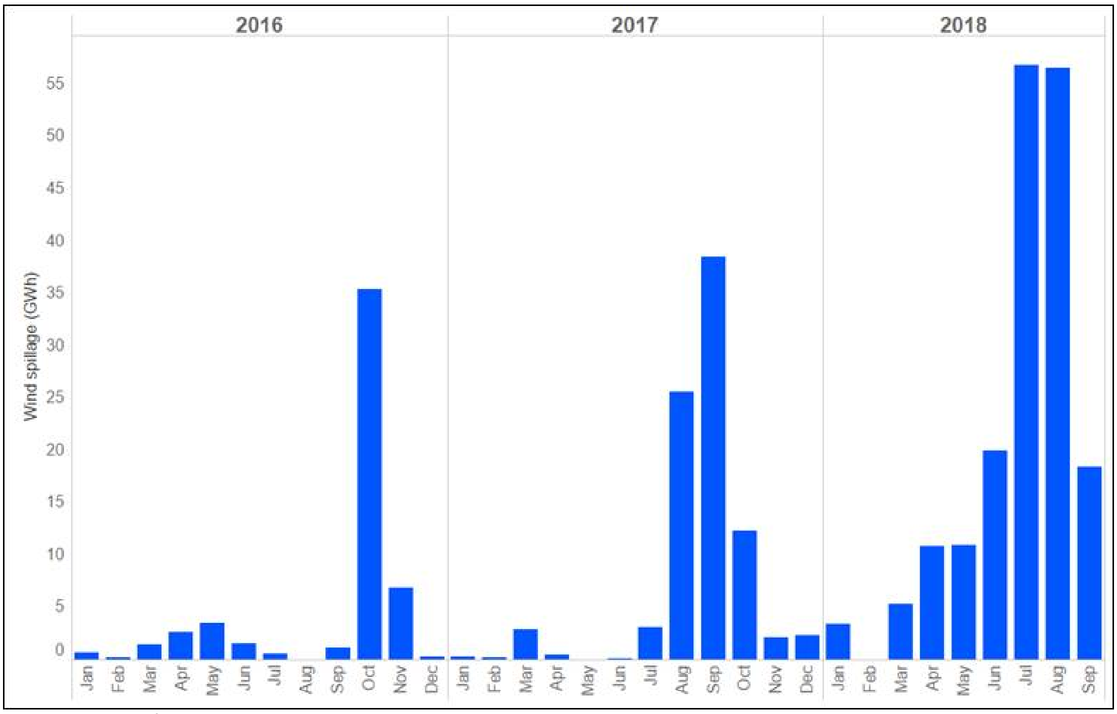
Beyond the minimum levels, AEMO applies constraints to maintain system security under certain operating conditions. In the case of South Australia, constraints are applied to limit output from asynchronous wind generators. The provision of additional system strength and inertia has the potential to provide economic benefits by alleviating these binding constraints and thereby increasing levels of competition in the wholesale market.[340] Separate constraints are applied for system strength and inertia. In the case of system strength, constraints are applied to limit the output of asynchronous generation in order to maintain stable operation of the power system. In the case of inertia, constraints may be applied to reduce power flows on interconnectors to limit the size of the rate of change of frequency (RoCoF) that would occur should the interconnector unexpectedly fail.

Significant wind energy is being 'spilled' as a result of these constraints. Figure 7.14 shows the total wind spillage in South Australia in GWh on a monthly basis from 2016 to September 2018. The wind spillage is calculated by the divergence of wind generator availability from the energy cleared. For example, a wind farm may have an availability of 50 MW but is constrained in dispatch to 45 MW, resulting in spillage of 5 MW. The total spillage values are

340 The extent to which constraints on wind generators could be alleviated would depend on the combination and location of specific generators providing system strength.

54.2 GWh in 2016, 88.0 GWh in 2017, and 182.5 GWh in 2018 (182.5 GWh represents approximately 5 per cent of total South Australian wind output as at September 2018).

Figure 7.14: Wind spillage in South Australia 2016-2018



Source: AEMC analysis

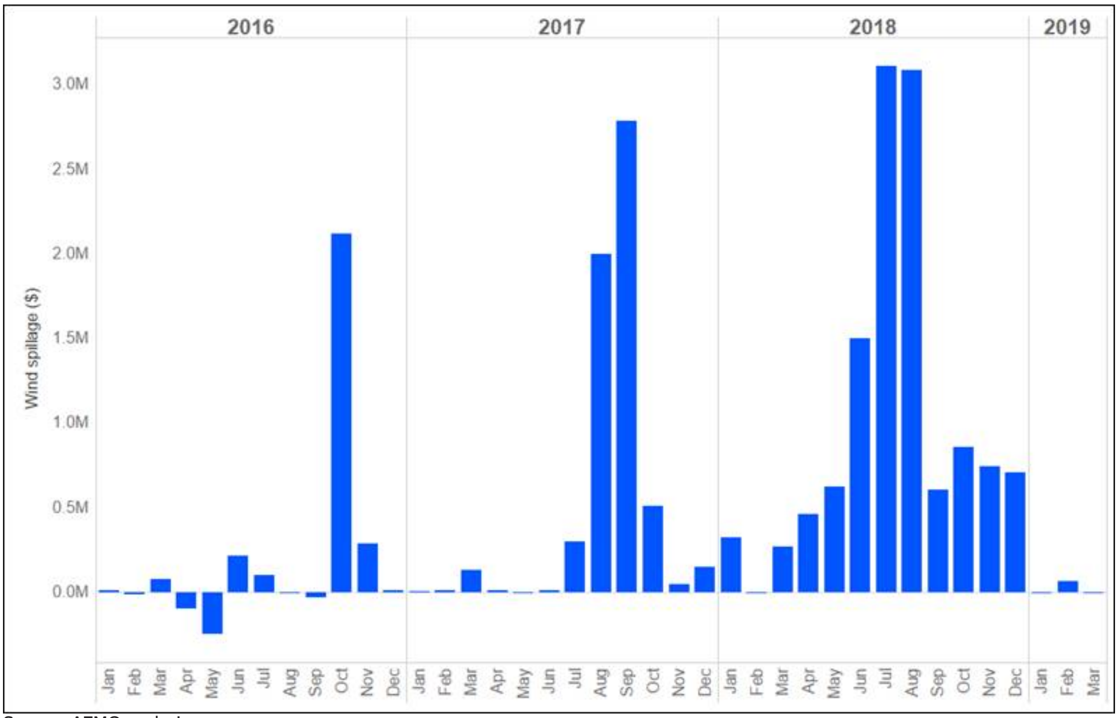
As can be seen, the degree of wind spillage is increasing. AEMO's Q3 2018 *Quarterly Energy Dynamics Report* states: "during Q3 2018, total curtailments of non-synchronous generation (large-scale wind and solar farms) in South Australia increased to around 150 GWh (or 10% of South Australian non-synchronous generation), with curtailment occurring for 26% of the time during the quarter. This was the highest amount on record and around 70 GWh higher than the next highest quarter (Q3 2017). Key drivers were record high wind generation and insufficient synchronous generators being available to meet system strength requirement".[341] This trend may continue as more wind capacity is installed in South Australia.

Figure 7.15 below shows the estimated values of wind spillage in South Australia on a monthly basis. The total spillage values are:

- $2.44 million in 2016;
- $5.97 million in 2017;
- $12.30 million in 2018; and
- $60.3 thousand in 2019 YTD.

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

Figure 7.15: Implied value of wind spillage in South Australia, 2016 to 2019 YTD



Source: AEMC analysis

These estimates are likely to be conservative because the analysis is confined to South Australia. Accurately estimating the cost of the South Australian wind constraints would involve assessing the difference between prices across the NEM generated by NEMDE when the constraints were in operation, and the lower prices that would be expected if the constraints were not imposed (meaning higher volumes of wind energy could be exported to other regions, thereby displacing more costly generators in those regions). Such analysis would require NEMDE to be rerun (with and without the constraints).

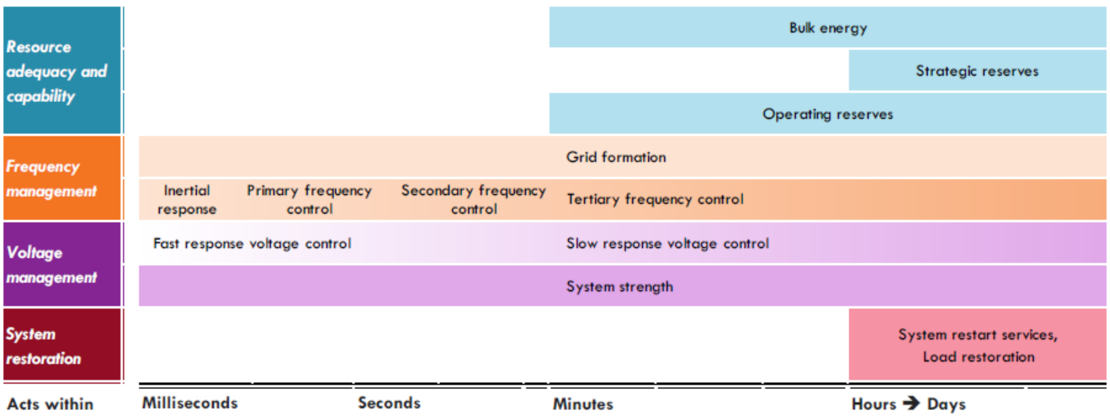
The NEM wide impact of constraints is similar to the NEM wide effect of intervention pricing – whereby prices in South Australia and elsewhere would, but for the use of intervention pricing, be lower as a result of the additional energy exported by South Australia when directions are in place. As discussed in section 4.7, the impact of intervention pricing due to system strength directions in 2018 was around $70.6m in South Australia, while the impact of intervention pricing in other regions (excluding the effect of the RERT on prices) was around $93m.

Of course, any such analysis would need to account for the transmission capacity of relevant interconnectors which may constrain the volume of wind energy that can be exported, and thus limit price impacts in other regions. In this regard, however, it is relevant to consider the future capacity to export wind from South Australia if and when the proposed South Australia – NSW interconnector is constructed. To realise the full potential benefit of that interconnector, sufficient system strength will be needed in South Australia to facilitate wind energy exports over the interconnector. This will have a bearing on the potential value that could be realised by developing a mechanism to incentivise the provision of system strength beyond minimum levels.

The Commission considers that the economic benefits available from the provision of additional system strength and inertia are likely to progressively increase as asynchronous forms of generation continue to connect and synchronous generators retire. As part of its future work program, the Commission is proposing to explore options to value additional system strength and inertia and to design and potentially implement a mechanism to pay for these services. The development of this mechanism will need to be undertaken in view of the range of other system services which may be necessary in the future to maintain a secure power system, and for which there are currently no incentives in place. There are many inter-relationships between these services, and they will need to be considered in a coordinated fashion in order to arrive at an efficient outcome in the interests of consumers. The ability to develop a mechanism that can accurately value a range of services across different locations in the network is likely to become increasingly important as the amount of asynchronous generation continues to grow in proportion to synchronous generation.

Figure 7.16 is taken from AEMO's *Power System Requirements Reference Paper* and shows the range of potential services for which procurement frameworks may need to be designed in the future.

Figure 7.16: Range of potential services needed



Source: AEMO, *Power system requirements - reference paper*, March 2018.

There are many interrelationships between these services. Some technologies may provide several services and, as such, a deficiency in that technology could lead to a number of potential technical impacts on the power system. Other technologies may provide some services but not others. Further work will be required to better understand these inter-relationships and to develop mechanisms that can efficiently value and incentivise the provision of these services. AEMO is currently undertaking work to better understand the interrelationships and gaps in the provision of the relevant services. This work will be important in the development of appropriate mechanisms.

8 LODGING A SUBMISSION

Written submissions on this consultation paper must be lodged with Commission by 16 May 2019 online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code EPR0070.

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions. The Commission publishes all submissions on its website, subject to a claim of confidentiality.

All enquiries on this project should be addressed to Katy Brady on (02) 8296 0634 or katy.brady@aemc.gov.au.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	See AEMC
CRA	Compensation recovery amount
FCAS	Frequency Control Ancillary Services
FFR	Fast frequency response
IP	Intervention pricing
IPWG	Intervention Pricing Working Group
ISP	Integrated System Plan
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEO	National electricity objective
NER	National Electricity Rules
NSCAS	Network support and control ancillary services
NTNDP	National transmission network development plan
PSCAD	Power systems computer aided design
RERT	Reliability and Emergency Reserve Trader
RRN	Regional Reference Node
SA	South Australia
SRD	Settlements residue distribution
SRMC	Short run marginal cost
TNSP	Transmission network service provider