AEMC

RULE

Australian Energy Market Commission

CONSULTATION PAPER

NATIONAL ELECTRICITY AMENDMENT (COMPENSATION FOR MARKET PARTICIPANTS AFFECTED BY INTERVENTION EVENTS) RULE 2020

PROPONENT

AEMO

11 JUNE 2020

INQUIRIES

Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

E aemc@aemc.gov.au
T (02) 8296 7800

Reference: ERC0284

CITATION

AEMC, Compensation for market participants affected by intervention events, Consultation paper, 11 June 2020

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.

CONTENTS

APPENDICES

TABLES

FIGURES

1 INTRODUCTION

There has been a significant increase in the use of intervention mechanisms by the Australian Energy Market Operator (AEMO) over the last three years, primarily in response to system security issues such as inadequate system strength in South Australia but also to manage system reliability. In response to this increased reliance on intervention mechanisms, AEMO and the AEMC have undertaken reviews relating to intervention pricing and the interventions framework, resulting in a number of recommended changes to the interventions framework.

On 19 September 2019, the AEMO submitted four rule change requests to the Australian Energy Market Commission (AEMC or Commission) dealing with various aspects of the compensation framework that is triggered when AEMO intervenes in the market. Two of these rule change requests are the subject of this consultation paper while the other two requests are being progressed separately.

The two rule change requests which are the subject of this consultation paper concern the amount of compensation payable to affected participants and market customers with scheduled loads under clause 3.12.2 of the National Electricity Rules (NER). Such participants may be eligible for compensation if they are dispatched differently as a result of an AEMO intervention event.[1] The rule change requests are:

- "Affected participant compensation for FCAS losses"[2] which seeks to include losses related to market ancillary services in the list of factors that can be considered when determining additional compensation claims lodged by affected participants.[3]
- "Compensation for scheduled loads affected by interventions"[4] which seeks to amend the way that compensation is calculated for market customers with scheduled loads which are dispatched differently as a result of an AEMO intervention event.[5]

Chapter 10 of the NER defines "affected participant" as a scheduled generator or scheduled network service provider which was dispatched differently as a result of an intervention event. The definition also includes “eligible persons”, being settlement residue distribution (SRD) unit holders who are entitled to receive an amount from AEMO where there has been a change in flow of a directional interconnector. Affected participants are compensated under clause 3.12.2 of the NER.

Market customers with scheduled loads may also be entitled to compensation if the scheduled load is dispatched differently as a result of an intervention event. Such customers

1 An "AEMO intervention event" is defined in chapter 10 of the NER as the exercise of the reliability and emergency reserve trader (RERT) in accordance with rule 3.20 or the issuance of a direction in accordance with clause 4.8.9.

2 AEMO, *Rule change proposal: Additional compensation for FCAS losses*, 19 September 2019. This rule change request is referred to in this paper as "Affected participant compensation for FCAS losses".

3 Market ancillary services are defined as "a service identified in clause 3.11.2(a)". That clause lists the eight frequency control ancillary services (FCAS), namely: fast raise, fast lower, slow raise, slow lower, regulating raise, regulating lower, delayed raise and delayed lower. Market ancillary services are generally referred to in this paper as FCAS.

4 AEMO, *Rule change proposal: Affected participant compensation for scheduled loads*, 19 September 2019. This rule change request is referred to in this paper as "Compensation for scheduled loads affected by interventions".

5 Scheduled loads are net consumers of electricity that register to participate in the central dispatch and pricing processes operated by AEMO.

are compensated under the same clause as affected participants but are not defined as affected participants.

Given that both rule change requests concern the amount of compensation payable under clause 3.12.2, the Commission has determined that it is appropriate to consolidate the requests and progress them via a single consultation process and rule. This will streamline the consultation process for stakeholders and may facilitate, where appropriate, a more integrated and consistent approach to the issues raised by the rule change requests.

This consultation paper has been prepared to facilitate public consultation on the two rule change requests and to seek stakeholder submissions.

This paper:

- sets out a summary of, and a background to, the rule change requests
- identifies a number of questions and issues to facilitate consultation on the rule change requests
- outlines the process for making submissions.

2 BACKGROUND - THE INTERVENTIONS FRAMEWORK AND RELATED REVIEWS

This chapter outlines:

- the interventions framework in the NER
- the recommendations of the AEMO-established Intervention Pricing Working Group
- the Commission's Investigation into intervention mechanisms in the NER
- related rule change requests and work streams.

2.1 The interventions framework in the NER

2.1.1 Intervention mechanisms

The interventions framework in the NER allows AEMO to intervene in the market for reliability purposes (e.g. in the event of a forecast breach of the reliability standard) or for power system security purposes (e.g. to maintain system strength levels). Intervention mechanisms are tools that are available to AEMO in circumstances where the market response has been inadequate to maintain a reliable and secure power system, or in response to unexpected events.

Broadly speaking, intervention mechanisms available to AEMO include the reliability and emergency reserve trader (RERT)[6], directions and instructions.[7] However, an "AEMO intervention event" is defined more narrowly in the NER. Such an event is defined to include exercising the RERT and issuance of directions but excludes instructions.

Interventions are typically used as a last resort and their use is governed by a number of principles and processes.[8] In addition, when AEMO intervenes in the market, two separate but related frameworks are triggered: one relates to "intervention pricing" and the other to compensation.

Intervention pricing is designed to reduce market distortion by preserving scarcity price signals that would otherwise be muted when AEMO dispatches the RERT or issues a direction to address a scarcity of energy or market ancillary services. It does this by setting the price at the level which AEMO reasonably considers would have applied had the intervention not occurred.[9] Intervention pricing is a transparent process that sends clear signals to the market, in terms of both operational and investment timescales.

6 Rule 3.20 of the NER.

7 Clause 4.8.9 of the NER.

8 A detailed discussion of the principles and processes associated with intervention mechanisms is set out in chapter 3 of AEMC, *Investigation into intervention mechanisms and system strength in the NEM, Consultation Paper,* 4 April 2019.

9 To do this, AEMO runs the NEM dispatch engine twice. The first run is known as the dispatch run and this is used to determine dispatch targets for all participants in the NEM (including those which have been directed to provide services). The second run is known as the intervention pricing run and is used to set the price at which the entire NEM clears. This run excludes those participants which have been directed to provide services and in this way seeks to determine what the price would have been if the intervention had not occurred.

2.1.2 Compensation framework

By contrast, the compensation framework is designed to make sure that "directed participants" (those who have been directed to provide services) can recover their costs, and "affected participants" (those scheduled generators and network services which are dispatched differently due to an AEMO intervention event which triggers intervention pricing) are put in the position they would have been in but for the intervention. Compensation is also payable to market customers with scheduled loads which are dispatched differently as a result of an AEMO intervention event which triggers intervention pricing.

Directed participants are compensated under clause 3.15.7, 3.15.7A and 3.15.7B of the NER. Directed participants who provide energy and market ancillary services (i.e. frequency control ancillary services or FCAS) are compensated under clause 3.15.7 at the 90th percentile price for the relevant region over the preceding 12 months. Participants who provide services other than energy and market ancillary services are compensated under clause 3.15.7A based on a "fair payment price" determined by an independent expert. If necessary, directed participants may also lodge a claim for additional compensation under clause 3.15.7B if the claim exceeds a compensation threshold of $5,000 per direction.[10]

Affected participants and market customers with scheduled loads are compensated under clause 3.12.2 of the NER, subject to a compensation threshold of $5,000 per intervention event.[11] Affected participants may be eligible to receive compensation from AEMO, or be required to repay additional revenue to AEMO, so that they are in the position they would have been in but for the intervention. In both cases, the amount owing is net of incurred or avoided direct costs. For example, if an affected participant is dispatched at a higher level due to an intervention, it will be required to repay to AEMO the additional revenue it earned net of the additional direct costs (e.g. fuel costs) it incurred in the course of generating more energy. Conversely, if an affected participant is dispatched less due to an intervention, it will be entitled to receive compensation from AEMO to put it in the position it would have been in but for the intervention. This compensation is net of the direct costs avoided by the participant as a result of generating less energy.

In contrast to the "two way" approach to compensation for affected participants, market customers with scheduled loads are eligible to receive compensation from AEMO if they are worse off due to an intervention. However, as stated by AEMO in its rule change request, scheduled loads are not required to repay revenue to AEMO if they are better off due to an intervention.[12] This issue is explored further in chapter 6.

10 See clause 3.15.7B(a4) of the NER.

11 That is, if the amount of compensation owing is less than $5,000, then no compensation is payable: see clause 3.12.2(b) of the NER.

12 AEMO, *Rule change proposal: Affected participant compensation for scheduled loads*, September 2019, p. 1. The relevant provisions in the NER on this issue are not consistent. For example, clause 3.12.2(2) provides that if the amount calculated using the formula is negative then "the adjustment that the market customer is entitled to claim ... is zero". This suggests that compensation for scheduled loads is "one way" only: that is, scheduled loads are entitled to receive compensation but are not liable to repay revenue to AEMO. By contrast, clause 3.15.8(a) (relating to cost recovery for energy directions) and clause 3.15.8(e) (relating to cost recovery for ancillary service directions) refer to the amount of compensation payable by affected participants and market customers *to* AEMO, as well as the amount of compensation payable to affected participants and market customers *by* AEMO. These provisions appear to indicate that compensation for scheduled loads should be "two way", consistent with the approach to affected participants.

AEMO automatically determines the amount of compensation owed to (or payable by) affected participants and market customers with scheduled loads by comparing their dispatch targets from the dispatch run and intervention pricing run used for the purposes of intervention pricing. If necessary, participants may also dispute AEMO's compensation calculation by lodging a claim with AEMO under clause 3.12.2(f). This is also subject to a compensation threshold of $5,000 per intervention event: that is, an adjustment claim must exceed $5,000.[13]

The cost of compensating both directed participants and those participants affected by a direction to obtain energy is passed through to market customers and thus consumers in the region that benefited from the intervention.[14] Where a direction is for the purpose of obtaining ancillary services, the cost of compensating directed and affected participants will be recovered in accordance with the cost recovery mechanisms applicable to each of the eight ancillary service markets.[15]

The application of the compensation framework lacks transparency: for example, no data about individual compensation payments is made public unless there is a dispute with a value in excess of certain thresholds.[16] Unlike the intervention pricing framework, the compensation framework is not designed to send signals to market participants.

2.1.3 Increasing use of interventions

As the energy market transition occurs and the composition of the generation fleet transforms from a small number of large, synchronous units to a large number of smaller, dispersed units that are non-synchronous, this has created increasing challenges for the maintenance of power system security. In relation to reliability, the NEM historically has largely delivered a high level of reliability, but as the supply/demand balance grows tighter, higher levels of unserved energy have been forecast. In addressing these challenges, AEMO has increasingly relied on intervention mechanisms - particularly directions to maintain system security.

Directions

In the period since April 2017, more than 515 directions have been issued by AEMO.[17] The majority of these (well over 400) have been issued to maintain system security in South Australia in response to inadequate system strength. Directions have also been used to manage voltage issues in Victoria. During an 18 day period in January-February 2020, 65 directions were issued in South Australia and Victoria to maintain system security and reliability while the South Australian region (along with Mortlake power station and Portland aluminium smelter) was separated from the rest of the NEM. This followed the loss of several

13 See clause 3.12.2(i) of the NER.

14 See clause 3.15.8(a) and (b) of the NER.

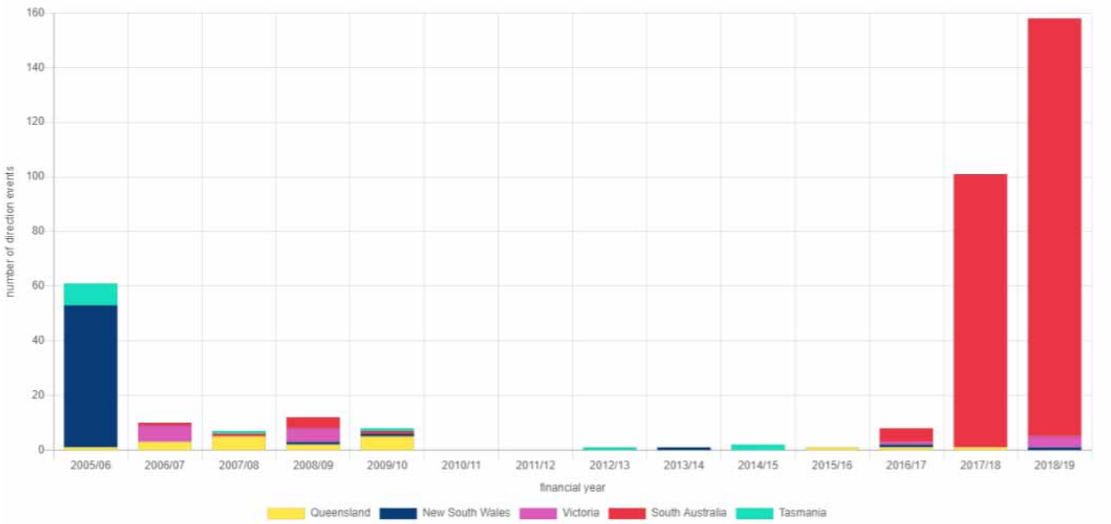
15 See clause 3.15.8(e) and (f) which in turn refers to the cost recovery formulae for market ancillary services set out in clause 3.15.6A of the NER.

16 In the *Interventions investigation final report*, the Commission recommended that the NER be amended to increase the transparency of the interventions framework, including in relation to the payment of compensation to directed and affected participants. See AEMC, *Investigation into intervention mechanisms in the NEM, Final Report,* 15 August 2019, p vii.

17 Data provided by AEMO as at 20 April 2020.

transmission towers on 31 January 2020 due to a severe storm. South Australia and Victoria were re-connected on 17 February 2020.[18]

Figure 2.1: Directions issued by AEMO in the last decade



Source: Reliability Panel, *2019 Annual Market Performance Review, Final report*, 12 March 2020, p. 147.

By contrast, reliability directions occur infrequently with only five reliability directions issued in the period since 2010.[19] The infrequent use of reliability directions reflects that, historically, the NEM has largely delivered a high level of reliability.

Reliability and emergency reserve trader

The primary intervention mechanism used by AEMO to manage reliability when the market response is inadequate is the RERT. The 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. It has been activated in November 2017 (one day), January 2018 (one day), January 2019 (two days), December 2019 (one day) and January 2020 (three days).[20]

18 AEMO, *Quarterly Energy Dynamics - Q1 2020*, April 2020, p. 24

19 In particular: directions were issued to Pelican Point power station to come online and increase available supply in February and March 2017, a direction was issued to Colongra power station to bid available and follow dispatch targets on 1 February 2020, and two reliability directions were issued to generators to service essential loads during the islanding of South Australia (between 31 January and 17 February 2020). See AEMO, *NEM Event - Direction to a South Australia Generator - 9 February 2017*, July 2017; AEMO, *NEM Event - Direction to a South Australia Generator - 1 March 2017,* January 2018; AEMO, *Quarterly Energy Dynamics - Q1 2020*, April 2020, p. 27. AEMO, *Renewable Integration Study: Stage 1 Report*, April 2020, p. 35.

20 Various AEMO RERT reports available at https://aemo.com.au/en/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting.

At present, AEMO can contract for reserves from three hours to twelve months ahead of the projected shortfall.[21] In March 2020, following advice from the Energy Security Board, COAG Energy Council agreed to implement interim measures to deliver further reliability by establishing an interim out-of-market capacity reserve and amending triggering arrangements for the Retailer Reliability Obligation (RRO). The measure, which the Energy Security Board is currently developing, allows AEMO to procure reserves for contract terms of up to three years, replacing the long notice RERT. They aim to keep unserved energy to no more than 0.0006% in any region in any year.[22]

Clause 4.8.9 instructions

Finally, as a last resort, AEMO may also issue clause 4.8.9 instructions to network service providers to shed load when available supply is insufficient to meet demand. While the most common form of clause 4.8.9 instruction has to date been for the purpose of load shedding, the definition of clause 4.8.9 instruction is in fact much broader. Under clause 4.8.9(a1), a *direction* is defined as a requirement on a registered participant to take action in relation to scheduled plant or a market generating unit. By contrast, a clause 4.8.9 *instruction* is a requirement for a registered participant to take some action other than in relation to scheduled plant or market generating units. As can be seen, clause 4.8.9 instructions are not limited to load shedding.

2.2 The Intervention Pricing Working Group

The application of intervention pricing has on some occasions resulted in anomalous and unexpected pricing outcomes. One such instance occurred on 9 February 2017 when a direction 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.[23]

This incident prompted AEMO to initiate a review of the intervention pricing methodology. 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.[24] It also established the Intervention Pricing Working Group (IPWG) to review the report and consider whether changes to the intervention pricing methodology and intervention framework more broadly should be made.

The IPWG comprised representatives of market bodies and industry. It met five times between November 2017 and May 2018 and identified a number of issues and proposed several rule changes. Four of these have already been actioned.

- On 30 May 2019, the Commission made a final determination and rule which streamlines the cost recovery process by aligning the timetables for compensation and settlement

21 In March 2020, the AEMC made a rule to provide AEMO with the flexibility to enter into multi-year contracts of up to three years under the RERT mechanism in Victoria. This will help address the short to medium term reliability challenges facing that state. The time-limited derogation will end in June 2023 and apply only in Victoria. The rule contains robust checks and balances so that multi-year contracts are only entered into in circumstances where they minimise costs to consumers. See AEMC, *Victorian jurisdictional derogation – RERT contracting, Rule determination*, 12 March 2020.

22 COAG Energy Council, Meeting communique, 20 March 2020, p. 1.

23 AEMO, *NEM Event – Direction to South Australia Generator – 9 February 2017*, July 2017, p. 15.

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

following an intervention. The rule also extended the deadline for participants to make additional compensation claims following an intervention, allowing participants more time to assess the impact of intervention events.[25] Both changes were recommended by the IPWG.

- Two further IPWG recommendations were progressed as part of the Commission's Investigation into intervention mechanisms in the NEM, discussed below. These related to intervention pricing and the $5,000 threshold applicable to directed and affected participant compensation.

The IPWG also recommended changes to the manner in which compensation is calculated for market customers with scheduled loads which are dispatched differently as a result of an intervention event. They also recommended that FCAS losses be included in the list of factors that can be considered when determining additional compensation claims by affected participants.

These two recommendations are the focus of this consultation paper.

2.3 The Investigation into intervention mechanisms in the NEM

In response to the increasing use of intervention mechanisms, the Commission commenced an investigation into intervention mechanisms and system strength in the NEM with the release of a consultation paper in April 2019.[26]

The consultation paper examined a number of issues relating to intervention mechanisms, including intervention pricing, compensation for directed and affected participants, mandatory restrictions, counteractions, the hierarchy of intervention mechanisms and price setting during RERT events. A final report was published in August 2019, with the Commission noting that further consultation would be undertaken when recommended rule change requests were submitted.[27]

A number of recommendations in the *Interventions investigation final report* have already been actioned. These include the following rule changes.

- Changes to the regional reference node (RRN) test set out in clause 3.9.3 of the NER were made in December 2019. The RRN test is used to determine whether AEMO should implement intervention pricing in connection with an "AEMO intervention event" (meaning activation of the RERT or issuance of directions). Under the revised RRN test, intervention pricing is to be implemented where an AEMO intervention event is for the purpose of obtaining a service for which there is a market price (i.e. energy or market ancillary services, or a service which is a direct substitute for these). Where the purpose of an intervention is to obtain a service for which there is no market price (e.g. voltage control or system strength), intervention pricing will not apply. This recognises that, in such circumstances, there is no relevant market price signal to preserve.

25 AEMC, *Intervention compensation and settlement processes, Rule determination*, 30 May 2019.

26 AEMC, *Investigation into intervention mechanisms and system strength in the NEM, Consultation paper,* 4 April 2019.

27 AEMC, *Investigation into intervention mechanisms in the NEM, Final report*, August 2019. The final report is referred to in this determination as the *Interventions investigation final report* or IIFR.

- Changes were also made to the circumstances in which affected participant compensation is payable in connection with an intervention event. Under the revised approach, affected participant compensation is only payable in circumstances where an AEMO intervention event triggers intervention pricing in accordance with the revised RRN test.[28] This is an important development when considering the AEMO rule change requests the subject of this consultation paper, noting that these rule change requests were submitted prior to the making of the December 2019 rule. As a result of narrowing the circumstances in which affected participant compensation is payable, the rule changes proposed by AEMO will (if made) affect a narrower set of intervention events - namely, those which trigger intervention pricing - and will have no impact on security interventions, which are far more common.
- As part of the same package of rule changes, the compensation threshold applicable to compensation payable to directed participants and affected participants was also amended. Under the revised approach, the $5,000 compensation threshold applies per intervention event rather than per trading interval (as was previously the case). This minimises the potential for directed and affected participants to incur loss as a result of AEMO intervention events.[29]

2.4 Other interventions related rule change requests

AEMO has submitted a number of other rule change requests to action recommendations made in the Interventions investigation final report. These relate to the following issues:

- **Recovering affected participant compensation for RERT activation**[30] — AEMO has proposed changes to RERT cost recovery arrangements to recover costs associated with compensating participants affected by a RERT activation from market customers in the region in which the RERT was exercised, allocated in proportion to the energy consumed in a trading interval.
- **Removal of mandatory restriction framework**[31] — AEMO has proposed the removal of the mandatory restriction framework from the NER.
- **Removal of obligation to counteract during intervention**[32] — AEMO has proposed the removal from the NER of the current obligation on AEMO to counteract during AEMO intervention events.
- **Removal of intervention hierarchy**[33] — AEMO has proposed that the requirement for AEMO to exercise RERT before issuing directions or instructions should be removed from the NER and replaced by a principle requiring AEMO to endeavour to minimise the costs and maximise the effectiveness of an intervention in the NEM.

28 AEMC, *Application of compensation in relation to AEMO interventions, Rule determination,* 19 December 2019.

29 AEMC, *Threshold for participant compensation following market intervention, Rule determination*, 19 December 2019.

30 For further information see https://www.aemc.gov.au/rule-changes/recovering-affected-participant-compensation-rert-activation

31 For further information, see https://www.aemc.gov.au/rule-changes/removal-mandatory-restrictions-framework

32 For more information, see https://www.aemc.gov.au/rule-changes/removal-obligation-counteract-during-intervention

33 For further information, see https://www.aemc.gov.au/rule-changes/removal-intervention-hierarchy

- **Compensation following directions for services other than energy and market ancillary services.**[34] — AEMO has proposed a change to the compensation framework for participants directed to provide services other than energy and market ancillary services: in particular, removing the right to apply for additional compensation and making the compensation process a one step rather than two step process.

The status of these rule change processes is as outlined below:

- On 28 May 2020, the AEMC initiated three rule change requests on *Recovering affected participant compensation for RERT activation*, *Removal of mandatory restrictions framework* and *Removal of obligation to counteract during intervention* through a consolidated and fast-tracked process.[35]
- On 28 May 2020, the AEMC initiated the *Removal of intervention hierarchy* rule change through a fast-tracked process.[36]
- On 11 June 2020, the AEMC initiated a rule change request on *Compensation following directions for services other than energy and market ancillary services* through a standard process.[37]

2.5 Other relevant rule changes and related work streams

As the NEM rapidly transitions to a market comprising a more diverse and complex mix of participants, multiple interrelated reform processes are under way to facilitate the evolution of regulatory frameworks. Several of these processes have implications for the broader context in which the Commission is progressing the rule changes that are the subject of this paper - including the extent to which interventions will in future be required to maintain system security and reliability. Areas of particular relevance are outlined below. Ongoing thinking in relation to these rule change requests will be informed by, and coordinated with, these other processes.

2.5.1 Energy storage systems rule change request

On 23 August 2019, AEMO submitted a rule change request seeking to amend the NER to recognise and define energy storage systems (ESS) and provide a framework that supports their participation and business models where there is a mix of technology types connecting behind a connection point.[38] The request notes that the current framework is designed around binary concepts of "generation" and "load" and the assumption of a one-to-one relationship between a given type of registered participant and an asset at a connection point that must (typically) be classified as either generation or load. It seeks to more efficiently accommodate increasing numbers of grid-scale connections where bi-directional electricity flows occur, such as utility scale batteries and pumped storage hydro.

34 For further information see https://www.aemc.gov.au/rule-changes/compensation-following-directions-services-other-energy-and-market-ancillary-services

35 For more information, see https://www.aemc.gov.au/rule-changes/changes-intervention-mechanisms

36 For more information, see https://www.aemc.gov.au/rule-changes/removal-intervention-hierarchy

37 For more information see https://www.aemc.gov.au/rule-changes/compensation-following-directions-services-other-energy-and-market-ancillary-services

38 AEMO, *Electricity rule change proposal, Integrating energy storage systems into the NEM,* August 2019.

The ESS rule change request is relevant to the question of how to compensate market customers with scheduled loads.[39] As discussed in section 3.5.3 of the ESS rule change request, AEMO considers that a bi-directional resource provider should be eligible for compensation in the event it is impacted by an AEMO intervention event, however further consideration is needed to determine the appropriate calculation and recovery method for this proposed new category. In particular, the request notes that it will be necessary to consider different "what-if" scenarios and (if relevant) transparent compensation measures depending on the composition of a bi-directional facility. Given the need to further consider these issues, AEMO did not propose amendments to rule 3.12 to accommodate bi-directional resource providers.[40]

The ESS rule change request is yet to be initiated. However, deliberations regarding the rule change requests the subject of this consultation paper can inform consideration of the ESS rule change request once it is initiated: e.g. how affected participants (including scheduled generators) and scheduled loads should be compensated if they are affected by an intervention event.

2.5.2 Wholesale demand response mechanism

On 11 June 2020, the Commission published its final determination and final rule to establish a wholesale demand response mechanism.[41] The final rule:

- introduces a new market participant category, a demand response service provider (DRSP)
- places obligations on DRSPs that, as much as practicable, replicate those applied to other scheduled participants, for example, similar information provision and scheduling obligations
- sets out a process for having baseline methodologies determined and applied to wholesale demand response units
- provides for DRSPs to be settled in the wholesale market for the wholesale demand response they have provided at the prevailing spot price
- sets out implementation timeframes for the mechanism, with the mechanism commencing on 24 October 2021.

Following consultation with AEMO and other stakeholders, the final rule incorporates a number of changes designed to reduce implementation costs. While existing systems and processes relating to scheduled loads will be used to facilitate DRSP participation in central dispatch, the Commission has determined that DRSPs should not participate in the systems and processes for FCAS cost recovery and affected participant compensation. This will avoid significant implementation costs for AEMO which would have delivered limited benefit. Similar

39 Three pumped hydro systems and five large batteries are scheduled loads as at the time of writing.

40 ibid, p. 23. One of the recommendations in the Interventions investigation final report was to narrow the circumstances in which compensation is payable to participants affected by an intervention event. In December 2019, the Commission made a final rule under which compensation is only payable to participants affected by an intervention event when the event triggers intervention pricing - or "what if" pricing. This addresses the above reference to considering different "what-if" scenarios. See AEMC, *National Electricity Amendment (Application of compensation in relation to AEMO interventions) Rule* 2019 No. 13.

41 AEMC, *Wholesale demand response mechanism, Rule determination*, 11 June 2020.

considerations regarding FCAS liabilities in relation to the rule change requests discussed in this paper are outlined in chapters 5 and 6.

2.5.3 Post 2025 market design

In March 2019, the COAG Energy Council requested the Energy Security Board (ESB) to advise on a long-term, fit for purpose market framework to support reliability, modifying the NEM as necessary to meet the needs of future diverse sources of non-dispatchable generation and flexible resources including demand side response, storage and distributed energy resource participation. The post 2025 program has been established to oversee and coordinate this program of work, bringing together multiple forward-looking reform initiatives to develop alternative market designs for recommendation to the COAG Energy Council.

There are seven core market design initiatives being progressed:

- Investment signals for reliability – this workstream is evaluating the case for introduction of a mechanism to incentivise investment in resources, and the pros and cons of specific mechanisms.
- Aging thermal generator strategy – the focus of this work will be on the market arrangements and regulatory approaches to ensuring that sufficient replacement capacity and system services are available to replace large, aging thermal generators as they exit the NEM over the coming decades.
- Essential system services – the focus of this work will be to develop an enduring regulatory framework that will enable the market operator and participants to meet future system services needs.
- Ahead markets – the ESB considers that security constrained economic dispatch of energy-only is, by itself, no longer sufficient to maintain system security. The ESB considers that new system services need to be established and remunerated and an ahead market is required to ensure system security going forward. The ESB will provide advice to COAG on a design for an ahead market and timing of implementation by the end of 2020. An ahead mechanism for the NEM can take a range of forms.
- Two-sided markets – A two-sided market is a market model that promotes direct interaction between suppliers and customers. There are a number of benefits to consumers from progressively moving to a two-sided market, who will be better able to manage their consumption and costs.
- DER markets – scope for this workstream is currently under development.
- Coordination of generation and transmission investment (COGATI) review – this review will substantively address the key challenge of integrating variable renewable energy into the electricity system, by the proposal to implement locational marginal pricing and financial transmission rights.

The ESB is due to provide detailed analysis by the end of 2020, along with the final 2025 report.[42]

42 Energy Security Board, *Moving to a two sided market*, April 2020, p. i.

These reforms have the potential to impact the future application of intervention and compensation frameworks in the NEM. The Commission and the ESB are coordinating on these pieces of work. For example, the recently published paper on the ahead market workstream discussed a unit commitment for security (UCS) process which would be used in the event that market responses as part of the pre-dispatch process are insufficient to provide required services. This would aim to provide confidence that critical resources would be available to deliver secure and reliable electricity supply in real-time.

The ESB notes that the need for the UCS is illustrated by the frequent use of directions to maintain system strength in South Australia.

The ESB paper notes that, even if the UCS process was in place, "AEMO would still have the capability to issue an ad hoc intervention outside the process if an unexpected system gap arises. However, the implementation of the UCS process will likely greatly reduce the need of such ad hoc directions."[43]

AEMC system services work program

In coordination with the ESB's work, the AEMC is progressing a number of rule change requests which focus on the issue of how best to procure and value system services such as system strength, inertia, frequency response and operating reserves. The development of mechanisms to value and procure system services is designed to facilitate an efficient and proactive approach to procuring required services, and reduce reliance on intervention mechanisms. Therefore, there are interactions between this work program and the rule changes considered in this paper. Again, the AEMC is coordinating closely across the different rule change requests. It is likely that whatever future market design will occur intervention mechanisms will continue to be needed.

43 ibid, pp 29-30.

3 DETAILS AND CONTEXT OF THE RULE CHANGE REQUESTS

The rule change requests from AEMO, including the context within which they have arisen, are discussed in turn below.

3.1 Affected participant compensation for FCAS losses

AEMO's rule change proposal entitled "Affected participant compensation for FCAS losses" was received on 19 September 2019. The rule change request can be found on the AEMC website.[44]

This rule change request seeks to include losses related to market ancillary services in the list of factors that can be considered when determining additional compensation claims lodged by affected participants. Further information about market ancillary services is set out in Appendix A.

3.1.1 Affected participant compensation

As set out in chapter 1, "affected participants" are defined as scheduled generators and scheduled network service providers which (a) were not the subject of a direction or reserve contract, but had its dispatched quantity affected by that direction or exercise of the RERT; or (b) were the subject of a direction or reserve contract, but had the dispatch quantity of other generating units or services affected by that direction or exercise of the RERT. The definition also includes "eligible persons", being settlement residue distribution (SRD) unit holders who are entitled to receive an amount from AEMO where there has been a change in flow of a directional interconnector.

When an affected participant is dispatched differently due to an intervention event that triggers intervention pricing, AEMO is required to calculate compensation to put the participant in the position it would have been in but for the intervention. It does this by comparing the position of the participant in:

- the dispatch run, which is used to dispatch the market during an intervention event and
- the intervention pricing run, which is used to set the price at which the market clears during an intervention event.

The latter run does not include the dispatch targets for any directed output, or the effect of the RERT, and thus seeks to establish what the market price would have been "but for" the intervention event.

To determine the quantum of affected participant compensation, clause 3.12.2(a)(1) states that affected participant compensation shall consider solely the items listed in clause 3.12.2(j). Paragraph (j) in turn lists:

44 https://www.aemc.gov.au/rule-changes/affected-participant-compensation-fcas-losses

- direct costs incurred or avoided by the affected participant as a result of the intervention event, specifically: fuel costs, incremental maintenance costs and incremental manning costs
- any amounts which the affected participant is entitled to receive under clauses 3.15.6 and 3.15.6A (being the trading amounts payable to market participants in relation to energy and FCAS respectively)
- the regional reference price (being the price for electricity).

Following a rule change made in December 2019, compensation is now only payable to affected participants and scheduled loads in connection with AEMO intervention events which trigger intervention pricing under clause 3.9.3 of the NER.[45] In essence, this means that such compensation will only be payable in connection with intervention events (exercising the RERT or issuing a direction) for the purpose of addressing a shortage of energy or FCAS.[46]

Compensation will no longer be paid to affected participants and scheduled loads as a result of security related interventions such as to obtain system strength or voltage support (i.e. security interventions other than to address a shortage of FCAS - referred to for ease of reference as "security interventions"). This reduces the costs to consumers and to AEMO of determining and paying compensation to affected participants and scheduled loads, noting that security interventions are significantly more frequent than reliability interventions.

3.1.2 Issues identified in the rule change request

AEMO notes in the rule change request that the list in clause 3.12.2(j) (discussed above) does not refer to FCAS prices and this has resulted in one claim for affected participant compensation for FCAS losses being rejected - discussed below.[47]

BOX 1: CLAIM FOR AFFECTED PARTICIPANT COMPENSATION IN RESPECT OF FCAS LOSSES

This involved a claim for additional affected participant compensation by a generator in South Australia. The claim followed the 1 December 2016 direction to Mortlake power station to desynchronise in order to restore the power system to a secure operating state. In the first instance, AEMO calculated affected participant compensation based on changes in the participant's energy dispatch targets due to the intervention. However, AEMO did not calculate compensation for changes in the participant's FCAS targets. The participant then lodged a claim for additional compensation and AEMO appointed Synergies Economic Consulting to determine the claim.

Synergies determined that the affected participant was not entitled to receive compensation with respect to loss of anticipated revenue from market ancillary services. While Synergies

45 AEMC, *Application of compensation in relation to AEMO interventions, Rule determination*, 19 December 2019.

46 While a shortage of FCAS is a security issue rather than a reliability issue, such interventions are referred to in this consultation paper as "reliability interventions" for ease of reference.

47 AEMO, Rule change proposal, p. 3.

acknowledged that there was ambiguity in clause 3.12.2, it determined that the specific reference to the regional reference price (for electricity) and the absence of any reference to market ancillary service prices suggested that compensation should not be payable in relation to foregone market ancillary service revenue. It noted that there is no clear rationale in the NER for this differential treatment of energy and market ancillary service revenues and suggested that this issue could be an issue for consideration in any future review of the compensation framework.

The Synergies determination is discussed further in chapter 5 and Appendix B.

Source: based on Synergies Economic Consulting, *Final report on compensation related to directions that occurred on 1 December 2016*, June 2017

3.1.3 Solution proposed in the rule change request

AEMO notes in the rule change request that frequency control is becoming more important in the NEM and costs are generally rising each quarter. At the same time, reliance on intervention mechanisms is increasing. Accordingly, AEMO considers it appropriate to amend the NER so that affected participants can be compensated if they incur FCAS losses as a result of an intervention event.

To achieve this, AEMO proposes to include FCAS prices amongst the compensable factors to be considered in determining additional compensation under clause 3.12.2(j). It considers that this achieves a "fairer outcome" for affected participants that may be negatively impacted by FCAS losses resulting from an intervention event.[48]

The rule change request include a proposed rule which adds a new sub paragraph (4) to clause 3.12.2(j). This new sub paragraph would refer to "ancillary service price published pursuant to clause 3.13.4(l)".

Issues arising in connection with the rule change request are further explored in chapter 5.

3.2 Compensation for scheduled loads affected by interventions

AEMO's rule change proposal entitled "Affected participant compensation for scheduled loads" was received on 19 September 2019. The rule change request can be found on the AEMC website.[49]

The rule change request seeks to amend the way that compensation is calculated for market customers with scheduled loads which are dispatched differently as a result of an AEMO intervention event.[50]

48 AEMO, Rule change proposal, p. 3.

49 https://www.aemc.gov.au/rule-changes/compensation-scheduled-loads-affected-interventions

50 While the rule change request refers to "affected participant compensation", market customers with scheduled loads sit outside the definition of "affected participants" in chapter 10 of the NER. Thus, while they may be considered to be participants which are affected by an intervention event, and are dealt with in the same clause as "affected participants", market customers with scheduled loads are not "affected participants" as defined in the NER.

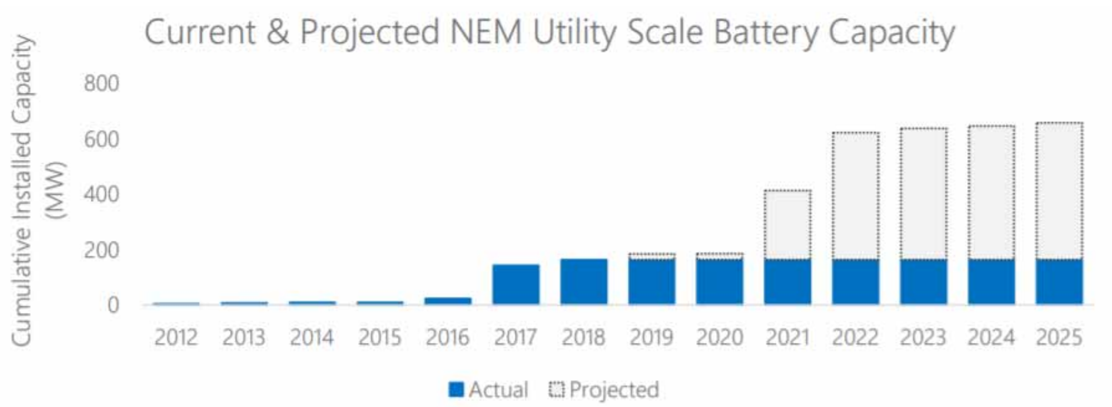
3.2.1 Background - compensating scheduled loads

Scheduled load is defined in the glossary of the NER as "a market load which has been classified by AEMO in accordance with Chapter 2 as a scheduled load at the Market Customer's request. Under Chapter 3, a Market Customer may submit dispatch bids in relation to scheduled loads."[51]

Scheduled loads are net consumers of electricity that register to participate in the central dispatch and pricing processes operated by AEMO. For the purposes of economic scheduling of electricity to meet demand, scheduled loads are essentially treated on equal terms with scheduled generating units.[52]

At present, there is relatively little scheduled load in the NEM: there are three pumped hydro power stations (Wivenhoe, Tumut 3 and Shoalhaven) and five utility scale batteries (Gannawarra, Hornsdale, Lake Bonney, Ballarat and ESCRI - registered as Dalrymple North Battery Energy Storage System).[53] This will likely change as more utility scale batteries are installed - see figure 3.1 for projected uptake to 2025.

Figure 3.1: Current and projected NEM utility scale battery capacity



Source: BNEF Bloomberg New Energy Outlook 2018, cited in AEMO rule change request, p. 2.

Under clause 3.12.2(a)(2), compensation is payable to market customers in respect of scheduled loads if they are dispatched differently as a result of an intervention event (and were not the subject of any direction that constituted the intervention event). AEMO calculates this compensation based in part on the difference between the amount of electricity actually consumed by the scheduled load and the amount of electricity that AEMO reasonably determines would have been consumed by the scheduled load but for the intervention event.[54] This is one of a number of factors set out in the compensation formula in clause 3.12.2(a)(2).

51 A market load is defined as a load at a connection point classified as a market load in accordance with Chapter 2.

52 AEMO, *Guide to scheduled loads*, p. 4.

53 AEMO, NEM registration and exemption list, available at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/registration

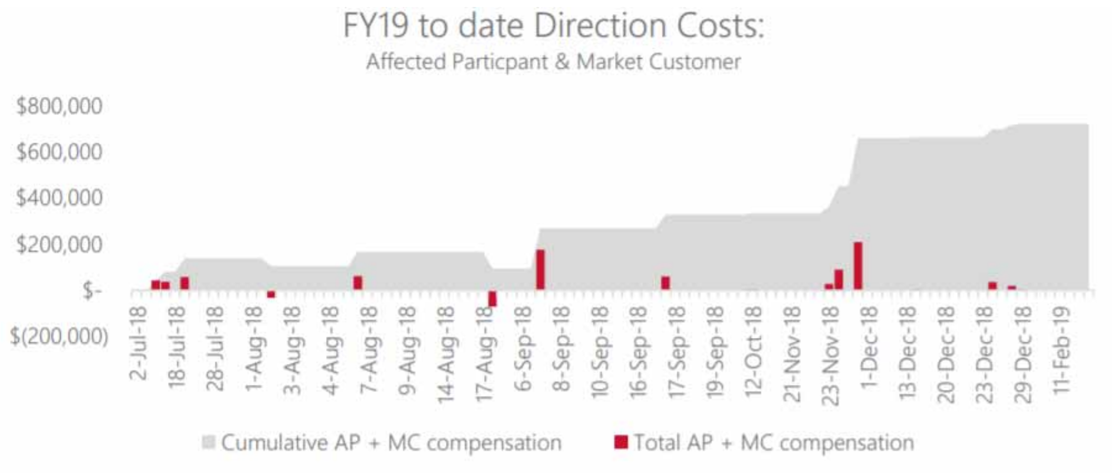
54 As with affected participants, this is done by comparing the dispatch targets for the participant in the dispatch run and the intervention pricing run.

AEMO notes that it has seen an increase in the amount of compensation paid (see figure 3.2) as a result of the increase in directions required in the NEM, especially in South Australia, where there is utility scale battery load and where well over 400 system strength directions have been issued in the period since April 2017.[55]

AEMO has advised the Commission that compensation has on some occasions been paid to utility scale batteries (scheduled load) which have been dispatched differently as a result of system strength directions. However, compensation payments to scheduled loads were infrequent due to the application of the $5,000 per trading interval compensation threshold which applied until December 2019.

Prior to December 2019, affected participants and market customers with scheduled loads were not eligible for compensation in respect of amounts less than $5,000 per trading interval. In December 2019, the Commission made a final rule to change the threshold so it now applies on a per intervention event basis, rather than a per trading interval basis.[56]

Figure 3.2: Compensation costs associated with SA directions



Source: AEMO, Rule change proposal, p. 2.
Note: AP = affected participant (scheduled generators and network service providers); MC = market customers with scheduled load.

As noted in section 3.1.2, system strength directions no longer trigger intervention pricing or the payment of affected participant compensation (a change which was made subsequent to the submission of this rule change request). However, reliability interventions - namely, exercising the RERT or issuing a reliability direction - still trigger such compensation payments.

55 AEMO, Rule change proposal, p. 2.

56 AEMC, *Threshold for participant compensation following market intervention, Rule determination*, 19 December 2019. It is not possible to examine Q1 2020 data to examine whether more affected participant compensation has been paid to scheduled loads in connection with system strength directions as a result of the change to the compensation threshold. This is because, in another rule made on 19 December 2019, the Commission narrowed the circumstances in which such compensation is paid. Under this rule, compensation is no longer payable to affected participants and market customers with scheduled loads in connection with security related interventions: AEMC, *Application of compensation in relation to AEMO interventions, Rule determination,* 19 December 2019.

In recent times, there have been compensation costs associated with RERT activations, as shown below.

Table 3.1: Costs associated with RERT in Q1 2020

	STATE	PRE-ACTIVATION COSTS ($M)	ACTIVATION COSTS ($M)	INTERVENTION COSTS ($M)	TOTAL COST ($M)	COST/MWH
4 January 2020	NSW	$4.6	$3.75	$0.015	$8.36	$28,703.86
23 January 2020	NSW	$4.61	$2.81	$0.12	$7.54	$14,821.80
31 January 2020	VIC	$0.01	$5.34	$2.19	$7.54	$12,823.13
31 January 2020	NSW	$4.85	$3.53	$2.55	$10.93	$22,381.03

Source: AEMO, *RERT Quarterly Report Q1 2020,* May 2020, p. 32.

The intervention costs shown in the table represent the affected participant 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 (settlement residue distribution unit holders) due to changes in interconnector flows, and therefore changes in the value of settlement residues.

The compensation costs associated with the RERT activations on 31 January 2020 were higher than other events, likely reflecting the fact that the spot price was at the market price cap for several hours that day.

3.2.2 Issue identified and solution proposed in the rule change request

To determine the quantum of compensation payable to market customers with scheduled loads which are dispatched differently due to an intervention, AEMO uses the formula set out in clause 3.12.2(a)(2) which includes the following inputs:

- RRP (in dollars per MWh) is the regional reference price in the relevant intervention price trading interval determined in accordance with clause 3.9.3(b)
- LF is the relevant loss factor for the scheduled load's connection point
- BidP (in dollars per MWh) is "the price of the highest priced price band specified in a dispatch bid for the scheduled load in the relevant intervention price trading interval"[57]
- QD (in MWh) is "the difference between the amount of electricity consumed by the scheduled load during the relevant intervention price trading interval determined from the metering data and the amount of electricity which AEMO reasonably determines would have been consumed by the scheduled load if the AEMO intervention event had not occurred".

57 Price band is defined as "a MW quantity specified in a dispatch bid, dispatch offer or market ancillary service offer as being available for dispatch at a specified price".

If the quantum of compensation determined using the formula is negative for the relevant intervention price trading interval, "the adjustment that the Market Customer is entitled to claim in respect of that scheduled load for that intervention price trading interval is zero". This contrasts with clause 3.12.2(e) which provides that, if the amount calculated in accordance with paragraph (c) is:

- negative, the absolute value of that amount is the amount *payable* to AEMO by the relevant person; or
- positive, the absolute value of that amount is the amount *receivable* from AEMO by the relevant person.

Clause 3.12.2(c) refers in turn to the calculation of compensation for affected participants (scheduled generators/network services), eligible persons (SRD unit holders), and market customers with scheduled loads. There is thus some inconsistency between:

- subparagraph (a)(2) which provides that, if the quantum of compensation for a scheduled load is determined to be negative, the adjustment that the market customer is "entitled to claim" in respect of that scheduled load for that intervention price trading interval is zero, and
- subparagraph (e) which provides that negative amounts are to be repaid by the relevant person to AEMO, while positive amounts are to be paid by AEMO to the relevant person.

The rule change request proposes to change the definition of "BidP" so it refers to the value of the highest priced band from which the scheduled load is dispatched, rather than to the price of the highest priced price band in the dispatch bid.

The rationale for the rule change request is the concern that the current definition of BidP fails to achieve the objective of ensuring that scheduled loads which are dispatched differently due to intervention events are not worse off as a result of the intervention.[58]

AEMO is concerned that the current definition of BidP could result in under compensation if the RRP is lower than or equal to the scheduled load's highest price bid band. It notes that it has not observed instances of compensation for scheduled loads being affected by this rule, and considers this may be due to clause 3.12.2(a)(2) under which market customers with scheduled load are entitled to receive compensation but are not required to repay any amounts to AEMO if they are better off as a result of an intervention.[59]

AEMO considers that the proposed rule will provide "increased certainty for participants that they will be fairly compensated for actions that support the reliability and security of the power system; and removal of any incentive for participants to avoid or minimise financial losses that may accrue due to interventions, potentially in ways that compromise AEMO's ability to manage the power system".[60]

58 This issue was identified and discussed by the AEMO-established Intervention Pricing Working Group.

59 This contrasts with the situation for affected participants which may be eligible to receive compensation from AEMO, or be required to repay additional revenue earned as a result of the intervention. As discussed further in chapters 5 and 6, there may be a need for greater clarity in relation to this aspect of clause 3.12.2 as there appear to be several inconsistencies in the rules relating to whether compensation for scheduled loads is one way only, or two way as for affected participants.

60 AEMO, Rule change proposal, p. 4.

AEMO acknowledges that the proposed change may increase the quantity of compensation payable by market customers and ultimately by consumers.[61] However, AEMO considers that the impact on compensation costs would be "comparatively minimal" given the small amount of scheduled load currently in the market. It also considers that "efficient incentives for market participants to support the reliability and security of the power system are in the long-term interests of consumers. Further, AEMO considers that the proposed changes strike a fair balance between the interests of market participants and consumers".[62]

Issues arising in connection with the rule change request are further explored in chapter 6.

61 Market customers bear the cost of directed and affected participant compensation associated with directions for energy: clause 3.15.8(a) and (b). For directions to obtain ancillary services, compensation costs are recovered from market customers, market generators and market small generation aggregators: clause 3.15.8(e)-(g).

62 AEMO, Rule change proposal, pp 3-4.

4 ASSESSMENT FRAMEWORK

4.1 Achieving the NEO/NGO/NERO

Under the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).[63] This is the decision-making framework that the Commission must apply.

The NEO is:[64]

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

Based on a preliminary assessment of the rule change request, the Commission considers that the most relevant aspects of the NEO are the efficient investment in, and efficient operation and use of, electricity services with respect to the price of electricity.

4.2 Proposed assessment framework

To determine whether the rule change proposal is likely to promote the NEO, the Commission will assess the rule change request against a number of principles, set out below.

At this stage, the Commission is seeking stakeholder views on its proposed assessment framework which includes the following criteria:

- **Transparency and predictability** – does the proposed approach provide clear and predictable arrangements for participants affected by interventions, thereby reducing uncertainty?
- **Efficiency** – is the proposed approach efficient in terms of administrative costs to participants? Does it send clear operational and investment signals to participants?
- **Risk allocation** – risk allocation and the accountability for investment and operational decisions should rest with those parties best placed to manage them. Does the proposed approach appropriately allocate risk to those parties best able to manage them?
- **Consistency** – do the rules adopt a consistent approach?

QUESTION 1: ASSESSMENT FRAMEWORK

Is the assessment framework appropriate for considering the proposed rule changes?

Are there other principles that should be considered in assessing the proposed rule changes?

63 Section 88 of the NEL.

64 Section 7 of the NEL.

4.3 Making a more preferable rule

Under s. 91A of the NEL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule will or is likely to better contribute to the achievement of the NEO.

4.4 Making a differential rule

Under the Northern Territory legislation adopting the NEL, the Commission may make a differential rule if, having regard to any relevant MCE statement of policy principles, a different rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule. A differential rule is a rule that:

- varies in its term as between:
    - the national electricity system, and
    - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems

but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

As the proposed rules relate to parts of the NER that currently do not apply in the Northern Territory, the Commission has not assessed the proposed rules against additional elements required by the Northern Territory legislation.[65]

65 From 1 July 2016, the NER, as amended from time to time, apply in the NT, subject to derogations set out in regulations made under the NT legislation adopting the NEL. Under those regulations, only certain parts of the NER have been adopted in the NT. (See the AEMC website for the NER that applies in the NT.) National Electricity (Northern Territory) (National Uniform Legislation) Act 2015.

5 AFFECTED PARTICIPANT COMPENSATION FOR FCAS LOSSES - ISSUES FOR CONSULTATION

Taking into consideration the assessment framework, a number of issues have been identified for initial consultation. Stakeholders are encouraged to comment on these issues as well as any other aspect of the rule change request or this paper.

This chapter examines issues relating to the proposal to allow affected participants to claim compensation with respect to FCAS losses in addition to energy. The chapter discusses:

- how FCAS losses are treated in other compensation frameworks established by the NER
- whether, as proposed by AEMO, affected participant compensation should encompass losses associated with FCAS in addition to losses associated with electricity
- if so, whether affected participants should receive FCAS compensation as part of the automatically calculated compensation process for affected participants, rather than having to lodge an additional compensation claim as proposed in the rule change request
- whether affected participant compensation in relation to FCAS should be net of liabilities in relation to FCAS.

5.1 How are FCAS losses dealt with under other compensation frameworks?

There are a number of compensation frameworks established by the NER which provide compensation for FCAS losses. In considering the AEMO rule change request, it is worth considering the approach adopted in these frameworks to the question of FCAS losses. These frameworks are discussed in turn below.

5.1.1 Directed participant compensation framework

Where a participant is directed to provide energy or FCAS, compensation with respect to both energy and FCAS is automatically calculated in the first instance in accordance with clause 3.15.7. This is based on the 90th percentile price for the relevant service (energy or FCAS) in the relevant region in the preceding 12 months. The formula for calculating compensation is set out in clause 3.15.7(c).

In relation to energy, it provides that compensation is to be calculated having regard for 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". Compensation for FCAS services is determined by multiplying the amount of the relevant market ancillary service which the directed participant has been enabled to provide by the 90th percentile price.

If a participant is directed to provide services other than energy or FCAS, it may be compensated under clause 3.15.7A under which an independent expert is appointed to determine a "fair payment price" for the service provided.

A directed participant may also opt to lodge a claim for additional compensation under clause 3.15.7B if it considers that it is still "out of pocket" following the calculation of compensation in accordance with clause 3.15.7 or clause 3.15.7A.[66]

Under clause 3.15.7B, a directed participant can seek additional compensation with respect to direct costs and loss of revenue. For example, if a participant is directed to provide energy, it may suffer losses in the FCAS markets. If compensation paid under clause 3.15.7 does not cover such losses then an additional claim could be made.

One example of this was the compensation paid to Pelican Point following a 1 December 2016 direction. Pelican Point was directed to reduce output to minimum load in order to manage a shortage of available FCAS while South Australia was islanded from the remainder of the NEM. At the time, Pelican Point was the largest generating unit online and thus determined the amount of contingency FCAS required.

Pelican Point lodged a claim under clause 3.15.7B for loss of both energy and FCAS revenue as result of being directed to reduce output. It was awarded compensation of just over $250,000 - comprising around $240,000 in lost energy revenue and around $10,000 in lost FCAS revenue.[67] These amounts were determined based on the different dispatch targets for Pelican Point in the dispatch run and intervention pricing run (i.e. the two runs of NEMDE used for the purpose of implementing intervention pricing).

5.1.2 Market suspension compensation framework

In 2018, the Commission made a final rule to establish a compensation framework which applies if, during a market suspension, prices are set by the market suspension pricing schedule (MSPS) rather than by the normal dispatch and pricing process.[68] The aim of the framework is to make sure that, when prices in the MSPS (which is based on average prices in the preceding four weeks) are too low to cover generators' estimated short run costs, compensation is automatically payable so that generators do not incur loss. This is designed to remove the current incentive for generators to withdraw from the market when MSPS prices are low and await direction by AEMO.[69]

Compensation is payable to scheduled generators and ancillary service providers (who are also scheduled generators) in the suspended region if prices in the MSPS are not sufficient to cover their estimated cost. Estimated costs will be calculated using "benchmark values": regionally-averaged estimated short run marginal costs for scheduled generators in each category (e.g. black coal, brown coal, open cycle gas turbine, combined cycle gas turbine,

66 AEMO has submitted a rule change request proposing that the determination of "fair payment price" compensation under clause 3.15.7A become a one-step rather than two-step process. Under the proposed approach, an independent expert would determine all compensation owing as part of the first process and the right to make an additional compensation claim under clause 3.15.7B would be removed. See https://www.aemc.gov.au/rule-changes/compensation-following-directions-services-other-energy-and-market-ancillary-services

67 Synergies Economic Consulting, *Final report on additional compensation claims arising from AEMO directions on 1 December 2016,* August 2017, p. 20.

68 AEMC, *Participant compensation following market suspension, Rule Determination*, November 2018

69 If a generator is directed by AEMO to provide energy or FCAS, it receives compensation based on the 90th percentile price under clause 3.15.7(c).

hydro, large-scale batteries) supplemented by a 15 per cent premium to account for divergences between estimated and actual costs.[70]

Where estimated costs exceed revenue earned by the generator under the MSPS, compensation will automatically be paid to cover the gap. This reduces the risk that generators and ancillary service providers will incur loss due to low MSPS prices. If automatically calculated compensation is insufficient or, where no compensation is automatically payable, revenue earned under the MSPS is insufficient to cover the generator's direct costs of participating in the market, a claim for additional compensation can be lodged with AEMO.[71]

Where AEMO issues a direction to a generator during a MSPS period, the MSPS compensation framework would apply, not the directions compensation framework.[72] This is designed to remove the incentive for a generator to withdraw and await direction if compensation based on the 90th percentile price (calculated under clause 3.15.7(c)) is more favourable to the generator than compensation determined under the MSPS framework.

5.1.3 Administered price period compensation framework

Where a participant suffers loss as a result of an administered price period (APP), the NER enables the participant to make a claim for direct costs and opportunity costs. APPs occur when the cumulative price threshold (CPT) is triggered following a prolonged period of high prices.[73] They are designed to limit market participants' exposure to financial stress which could ultimately impact market stability and integrity.

The potential for generators with high costs to incur a loss during such periods may create a disincentive for them to supply energy and ancillary services which could negatively impact the reliability and security of the electricity system. To minimise these disincentives, the NER allow participants to claim compensation where they incur a loss during an APP.[74]

The objective of this framework is to maintain the incentive for generators and network service providers to supply energy, ancillary service providers to supply ancillary services and market participants with scheduled load to consume energy during an APP. By providing a compensation framework, the NER reduce the probability that market participants with high marginal costs will await a direction from AEMO rather than dispatch voluntarily during such periods.

The compensation framework allows market participants to claim compensation if a net loss is incurred over an eligibility period (defined as a trading day, or part thereof, when an APP is in place). The question of whether loss is incurred is based on whether total costs (direct and opportunity) exceed total revenue from the spot market during the eligibility period.

70 See clause 3.14.5A of the NER.

71 See clause 3.14.5B of the NER.

72 See clause 3.15.7(d1) of the NER.

73 When the cumulative sum of spot prices in a region across a rolling seven day period exceeds the CPT (currently set at $221,100), an administered price cap (APC)of $300/MWh is imposed, together with an administered floor price of -$300/MWh. This administered price period continues until the rolling seven day cumulative price drops back below the level of the CPT.

74 See clause 3.14.6 of the NER.

Ancillary service providers can claim compensation for loss due to the application of an APC but no such claims have been made. Only one claim has been lodged under the APP framework and this related to losses in the energy market. This was the claim by Synergen that followed an APP in the South Australian energy market in early 2009. Synergen claimed compensation on the basis that the APC prevented it from recouping the costs of its Port Lincoln gas turbine and Snuggery power station. The AEMC determined that Synergen met the criteria for compensation, and that AEMO should pay it compensation of around $130,500.[75]

5.2 Should affected participants be eligible for compensation in relation to FCAS?

The compensation framework for interventions reflects, among other things, the outcomes of a review of directions undertaken in 2000 by NEMMCO and NECA.[76] That review concluded that directed participants should receive a “fair payment” that would cover the cost incurred in complying with the direction. It also concluded that "third parties whose market dispatch is affected by direction should also be compensated so that their financial position is unaffected by the direction".[77]

The review was undertaken prior to the introduction of the FCAS markets but noted that markets were being proposed for some ancillary services in the near future.[78] The directions review report noted that there was a need to establish a consistent framework for directions in those other ancillary services sectors.

Clause 3.12.2 sets out the compensation framework for affected participants and scheduled loads which are dispatched differently as a result of an AEMO intervention event. It has formed part of the NER since their commencement in 2005 (though prior to 2008 it was numbered differently, as clause 3.12.11). Clause 3.12.2 refers to terms such as dispatch and trading amounts, both of which terms encompass energy *and* FCAS. It also refers in clause 3.12.2(j)(2) to clause 3.15.6A (the provision which sets out the formulae used to calculate trading amounts for each of the eight FCAS markets) and so clearly alludes to the existence of the FCAS markets. However, it does not refer to ancillary service prices, as it does to electricity prices (the regional reference price). The reason for this is not clear.

The issue of how to interpret clause 3.12.2 with respect to FCAS losses was discussed by Synergies Economic Consulting when it declined a claim for additional affected participant compensation to recoup FCAS losses. This unsuccessful claim is referenced by AEMO in its rule change request and discussed in more detail in Appendix B.

Syneriges concluded its report with the following comment:[79]

75 AEMC, *Participant compensation following market suspension, Consultation paper*, May 2018, pp. 11-13.

76 These were the predecessors of AEMO and the AEMC.

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

78 The Australian Competition and Consumer Commission authorised changes to the National Electricity Code to establish the eight FCAS markets in 2001, not long after the review of directions was completed.

79 Synergies Economic Consulting, *Final report on compensation related to directions that occurred on 1 December 2016*, June 2017, p. 37.

> There is some ambiguity in clause 3.12.2 as to whether it allows for compensation for foregone ancillary services revenue. We conclude that it does not, for the following reasons:
>
> - the set of criteria that must be considered and which can solely be considered make no express reference to ancillary services prices but do expressly reference spot market prices in the form of the regional reference price. This indicates that compensation is intended to be confined to foregone energy spot market revenues;
> - in so far as clause 3.12.2 alludes to ancillary services, it does not do so in a way that indicates an intention to allow for the compensation of foregone ancillary services revenue; and
> - the approach that the claimant set out for determining its claim is not confined solely to the factors set out in clause 3.12.2
>
> ... In reaching this determination, we are mindful that there are ambiguities in clause 3.12.2 that we have had to resolve. It is difficult to determine whether the purpose of clause 3.12.2 is to compensate more generally for foregone revenues or, consistent with other some other compensation clauses in the NER, to ensure that revenues earned by an Affected Participant are not less than the costs that it incurs. If it is the former, it is difficult to determine whether it refers to all possible sources of foregone revenue.

The central question in considering the AEMO rule change request is whether compensation should be payable to affected participants, or payable by affected participants to AEMO, to put such participants in the position they would have been in with respect to FCAS but for the intervention event.

5.2.1 Internal consistency between clause 3.12.2 and cost recovery provisions

Amending clause 3.12.2 to include FCAS could improve internal consistency within the NER, noting that clause 3.15.8 - which deals with "funding of compensation for directions" - presumes that affected participant compensation is payable in relation to ancillary service directions. Clause 3.15.8(e) requires AEMO to calculate the "ancillary service compensation recovery amount" which comprises the sum of:

- the total compensation payable to AEMO by affected participants and market customers under clause 3.12.2 in respect of a direction for the provision of that ancillary service, plus
- the trading amounts retained by AEMO under clause 3.15.6(b),

less the sum of:

- the total compensation payable by AEMO to affected participants and market customers under clause 3.12.2 in respect of a direction for the provision of that ancillary service, plus
- the total compensation payable to directed participants under clause 3.15.7(a) in respect of a provision of that ancillary service, plus

- the total amount payable by AEMO to the independent expert under clause 3.12.3(c) if one was appointed to determine a claim in relation to that ancillary service direction.

This mirrors the approach to recovering the cost of energy directions, set out in clause 3.15.8(a) and (b).

There is a similar provision in clause 3.15.10C relating to intervention settlements. It refers in clause 3.15.10C(a)(3)(i) to "the total amount payable to AEMO by affected participants and market customers calculated pursuant to clause 3.12.2(c)", and in clause 3.15.10C(a)(3)(iii) to "the total amount payable by AEMO to affected participants and market customers pursuant to clause 3.12.2(c)".

Both of these provisions refer to compensation for both affected participants and market customers with scheduled loads[80] as a two way process, whereby participants may receive compensation if they are worse off as a result of an intervention, or be required to repay revenue if they are better off.

The wording of these provisions focuses on the nature of the direction - being either a direction for the provision of energy or a direction for the provision of an ancillary service. That is a slightly different focus to the question of whether a participant is dispatched differently, either in relation to energy dispatch targets or FCAS enablement targets, as a result of a direction. For example, it is possible that, following a direction for the provision of energy services, a participant's dispatch targets could be affected with respect to both energy and FCAS.

However, it is also reasonable to suggest that a direction for energy is likely to result in other participants' energy dispatch targets being affected, and a direction for ancillary services is likely to result in other participants' FCAS targets being affected. Thus, it appears that clauses 3.15.8 and 3.15.10C assume that compensation is payable to *and by* affected participants and market customers with respect to both energy *and* FCAS directions.

5.2.2 Cost implications

In considering whether to amend clause 3.12.2 to include FCAS, regard needs to be had for any additional compensation costs that will be passed through to market participants and, ultimately, consumers.

In this regard, it is relevant to note that, as of 20 December 2019, affected participant compensation is only payable in respect of AEMO intervention events (RERT and "reliability" directions) that trigger intervention pricing under clause 3.9.3(b) of the NER.[81] Such interventions are still relatively infrequent (and far less frequent than security related

80 This is relevant to the other AEMO rule change request discussed in this consultation paper, *Compensation for scheduled loads affected by interventions*, discussed further in chapter 6.

81 AEMC, *Application of compensation in relation to AEMO interventions, Rule determination*, 19 December 2019. Clause 3.9.3(b) was also amended on 19 December 2019 such that intervention pricing now only applies to interventions for the purpose of obtaining a service that is traded in the market: i.e. energy or FCAS, or a direct substitute for these. See AEMC, *Application of the regional reference node test to the reliability and emergency reserve trader, Rule determination*, 19 December 2019.

interventions).[82] Given this, the cost implications of the proposed change are more limited than would have been the case prior to 20 December 2019.

Further, if a two way compensation process were to be adopted, then - consistent with the cost recovery provisions mentioned above - the amount of compensation cost passed onto to other participants would be the net amount of compensation paid out to affected participants and revenue repaid by affected participants.

As well as considering compensation cost implications for other participants and, ultimately, consumers, it is important to consider the position of the participants which are dispatched differently as a result of an intervention. When the Commission made its final rule in December 2019 concerning the circumstances in which affected participant compensation should be payable, it considered that reliability interventions typically occur during periods when the supply demand balance is tight and spot prices are generally high. As such, being dispatched differently during such periods can impact important revenue-earning opportunities for market participants. This was a factor in the Commission's decision to retain affected participant compensation in respect of reliability interventions, even though the NEM is an open access market in which generators do not have a right to be dispatched.[83]

This is a relevant factor in considering whether to implement AEMO's proposal to compensate participants for changes in FCAS revenues resulting from reliability interventions.

Stakeholder views are sought as to whether affected participant compensation should be payable with respect to FCAS, consistent with the approach to energy.

QUESTION 2: SHOULD AFFECTED PARTICIPANT COMPENSATION INCLUDE FCAS?

Should clause 3.12.2 be amended so that affected participant compensation is payable in respect of FCAS?

5.3 How should affected participants be compensated with respect to FCAS?

The AEMO rule change request proposes to amend clause 3.12.2(j) so that an affected participant could lodge an adjustment claim in order to seek compensation in relation to FCAS losses. This raises two questions:

1. Should an affected participant be required to lodge an adjustment claim if it has suffered loss with respect to FCAS revenue as a result of an intervention event? This would

82 In the period since 2010, the RERT has been activated on a small number of occasions: in November 2017 (one day), January 2018 (one day), January 2019 (two days) and January 2020 (three days). In the period since 2010, only five reliability directions have been issued: in February and March 2017, and in February 2020, two directions during the SA islanding event. By contrast, well over 450 system strength directions have been issued in South Australia in the period since April 2017.

83 AEMC, *Application of compensation in relation to AEMO interventions, Rule determination*, 19 December 2019, p. iv.

increase administrative costs to both participants and AEMO relative to the approach adopted in relation to energy.[84]

2. This approach presumes that the affected participant will only lodge an adjustment claim in relation to FCAS if it is out of pocket.[85] However this creates an inconsistency as between energy and FCAS, asymmetry with respect to FCAS compensation, and inconsistency with the cost recovery provisions discussed above.

As noted previously, where an affected participant's energy dispatch targets change as a result of an intervention event, AEMO will automatically compensate an affected participant or require the affected participant to repay to AEMO additional revenue earned due to the changed dispatch targets.[86] For example, if a generator is constrained down by NEMDE,[87] 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 received based on their dispatch targets in the dispatch run (combined with the price from the intervention pricing run), and the amount they would 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.

The AEMO proposal does not involve this initial calculation of FCAS compensation payable to or by affected participants. As such, the proposed approach (allowing affected participants to lodge an adjustment claim in relation to FCAS losses) would reward affected participants which are negatively impacted by an intervention but not address the reverse situation, contrary to the objective in clause 3.12.2(a)(1) of putting affected participants in the position they would have been in but for the intervention.

As well as being inconsistent with the cost recovery provisions outlined earlier, this also raises questions about whether the proposed approach strikes an appropriate balance between the interests of affected participants on the one hand and, on the other, market participants and consumers who bear the cost of compensation.[88]

Stakeholder views are sought on whether clause 3.12.2 should be amended in the manner proposed by AEMO (i.e. so that the position with respect to FCAS is dealt with only in paragraph (j)) or whether consideration should be given to also including FCAS in paragraph (c)(1). That paragraph requires AEMO to advise affected participants of the level of dispatch that would have applied had the intervention event not occurred, and the trading amount

84 If a participant is affected with respect to energy revenue, compensation is in the first instance calculated automatically by AEMO without the participant having to lodge a claim.

85 This is reflected in the AEMO rule change request title, "Additional compensation for FCAS losses", and the reference on page 3 of the rule change request to participants who are "negatively impacted".

86 See clause 3.12.2(c) of the NER.

87 This means that they generate less in the dispatch run than in the intervention pricing run.

88 For directed and affected participant compensation, energy direction compensation costs are passed through to market customers and ultimately to consumers: clause 3.15.10C(a) and (b). However for ancillary service directions, compensation costs are recovered consistent with the cost recovery approach for the various FCAS markets - that is, from generators, small generation aggregators and market customers: clause 3.15.10C(e) - (g).

that would have resulted from that level of dispatch, less the trading amount actually paid. The appropriate adjustment is then included in participants' final statements in accordance with clause 3.12.2(d).

Some factors relevant to this question are outlined below:

- Information regarding dispatch target changes will be available to AEMO given that affected participant compensation is only payable in connection with interventions that trigger intervention pricing; this means AEMO will have access to the energy and FCAS targets set out in the dispatch run and intervention pricing run, thus enabling the above calculation to be made.
- Intervention events that trigger intervention pricing (under the revised "regional reference node test", which was also amended in December 2019[89]) are relatively infrequent and are generally of short duration; as such, requiring AEMO to provide this advice to affected participants with respect to FCAS should not entail a significant additional workload.
- If affected participants are not required to repay additional FCAS earnings to AEMO (consistent with the approach to energy), the "compensation recovery amount" will be greater (all else equal) with cost implications for consumers and the NEO. The compensation recovery amount is the amount of money that needs to be recouped from other participants in order to cover the cost to AEMO of compensating directed and affected participants in the wake of an intervention event.[90]

QUESTION 3: HOW SHOULD FCAS BE INCLUDED IN AFFECTED PARTICIPANT COMPENSATION?

Do stakeholders consider it appropriate for FCAS to be included only in clause 3.12.2(j) - the provision relating to adjustment claims - as proposed by AEMO?

Alternatively, should consideration be given to including FCAS in the automatically calculated compensation determined in accordance with clause 3.12.2(c)(1), in addition to including FCAS in paragraph (j)?

5.4 Should FCAS liabilities be included in direct costs incurred or avoided?

In accordance with clause 3.12.2(j)(1), AEMO takes into account direct costs incurred or avoided when it calculates affected participant compensation following changes to energy targets. That is, if an affected participant is dispatched less as a result of an intervention, it

89 AEMC, *Application of the regional reference node test to the reliability and emergency reserve trader, Rule determination*, 19 December 2019.

90 The compensation recovery amount 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. See clause 3.15.8(a) and (e) of the NER.

will be entitled to receive compensation for loss of revenue, net of the direct costs (e.g. fuel costs) it avoided as a result of generating less energy.

Conversely, if an affected participant is dispatched more as a result of an intervention, it will be required to repay to AEMO the additional revenue earned, net of the additional costs it incurred as a result of generating more energy. AEMO estimates avoided or incurred direct costs using short run marginal cost data that is assembled for planning purposes.[91]

AEMO notes in its rule change request that FCAS costs have been rising and the Commission notes that FCAS costs reached record levels in Q1 2020 (see figure A.2 in Appendix A). During the recent SA islanding event, high FCAS costs prompted several wind farms to reduce their output to reduce their FCAS liabilities. For example on 12 February 2020, when the South Australian raise 60 second FCAS price spiked to $14,500/MWh for two hours, 11 of 14 online South Australian wind farms self-curtailed output due to high FCAS liabilities.[92] [93]

This raises a question as to whether affected participant compensation should be calculated net of FCAS costs (liabilities) incurred or avoided, consistent with the approach adopted in relation to energy costs incurred or avoided (fuel, maintenance, staff). That is, where changed dispatch targets impact a participant's FCAS liabilities, there may be a case to take this into account when determining the appropriate amount of affected participant compensation.

Such an approach would be in line with the reality that many providers of FCAS contingency in particular also have to pay for that service, as the FCAS contingency recovery mechanism is based on the total energy generated in the trading interval. Accordingly, this cost forms part of the short run cost of operating the unit, similar to the cost of fuel.

In considering whether FCAS liabilities should be taken into account in determining the quantum of affected participant compensation, it is appropriate to consider whether the additional cost and complexity of taking this into account is warranted as part of the automatic calculation of affected participant compensation. It may be more efficient to allow affected participants to lodge an adjustment claim under clause 3.12.2(f) when exceptional circumstances - such as those during the recent SA islanding event - impact their FCAS liability in a material way. Stakeholder views on this would be welcome.

This administrative cost and complexity was a factor in the Commission's final determination and rule to establish a demand response mechanism.[94] The Commission determined that, to reduce the cost of implementing the demand response mechanism, FCAS costs would not be recovered from demand response service providers. This decision was informed by advice from AEMO that implementing this would be costly and would provide limited benefits. Similar factors will need to inform consideration of this issue in relation to participants affected by intervention events.

91 Thus the process is relatively automatic and is not dependent on the specific circumstances of a given intervention event.

92 AEMO, *Quarterly Energy Dynamics, Q1 2020,* April 2020, p. 29.

93 Under the FCAS framework, contingency raise FCAS costs are pro-rated over market generators based on their energy generation in the trading interval.

94 AEMC, *Wholesale demand response mechanism, Rule determination,* 11 June 2020.

QUESTION 4: SHOULD AFFECTED PARTICIPANT COMPENSATION BE NET OF FCAS LIABILITIES?

If FCAS compensation is included in clause 3.12.2, should the calculation of affected participant compensation take into account the impact on FCAS liabilities of changed dispatch targets resulting from an intervention event?

Should this be considered in each case as part of the automatic calculation of compensation or be an option available to participants via an adjustment claim?

6 COMPENSATION FOR SCHEDULED LOADS AFFECTED BY INTERVENTIONS - ISSUES FOR CONSULTATION

Taking into consideration the assessment framework, a number of issues have been identified for initial consultation. Stakeholders are encouraged to comment on these issues as well as any other aspect of the rule change request or this paper.

This chapter examines issues relating to the proposal to amend the formula used to determine the compensation payable to scheduled loads affected by interventions, including:

- whether the definition of BidP should be amended as proposed by AEMO so that affected participants are not out of pocket
- whether compensation should also be payable in respect of FCAS (as well as energy), consistent with:
  - the objective that affected participants should not be out of pocket as a result of an intervention
  - the rule change request discussed in chapter 5 regarding affected participants being compensated for FCAS losses
  - cost recovery provisions in the NER which presume that FCAS compensation is payable to (and by) market customers with scheduled loads
- whether FCAS compensation for scheduled loads (if payable) should be net of any adjustment required in relation to FCAS liabilities
- whether compensation should be two way rather than one way, consistent with the approach to affected participants and cost recovery provisions in the NER.

6.1 How scheduled loads are dispatched in NEMDE

Clause 3.8.1(a) of the NER requires AEMO to operate a central dispatch process to dispatch scheduled generating units, semi-scheduled generating units, scheduled loads, scheduled network services and market ancillary services in order to balance power system supply and demand, using its reasonable endeavours to maintain power system security in accordance with Chapter 4 and to *maximise the value of spot market trading on the basis of dispatch offers and dispatch bids*.

Clause 3.8.1(b) provides that the central dispatch process should aim to *maximise the value of spot market trading* i.e. to *maximise the value of dispatched load*[95] based on dispatch bids less the combined cost of dispatched generation based on generation dispatch offers, dispatched network services based on network dispatch offers, and dispatched market ancillary services based on market ancillary service offers.

95 The value of dispatched load equals (dispatched load x dispatch bid band price, as referred to regional reference node), summed for all scheduled loads: AEMO, *Guide to scheduled loads*, p. 9.

Maximising the value of spot market trading is known as the objective function of the NEM dispatch engine (NEMDE). It is expressed as being subject to dispatch offers, dispatch bids and market ancillary service offers, as well as a long list of network constraints, power system security requirements and other factors set out in clause 3.8.1(b) sub-paragraphs (1) to (12).

Clause 3.8.7 of the NER covers the structure of dispatch bids. A market participant must submit a scheduled load's maximum capacity in ten price bands in the daily energy bid. Each price band associates a quantity of electricity consumption at the load's local connection point with a local price for the scheduling of that quantity of electricity. Each band price represents the maximum market clearing price that the market participant is willing to pay before decreasing the electricity consumption of their scheduled load by up to the MW increment in that band for the specified trading interval.

Under clause 3.8.7(h) of the NER, all band prices for scheduled loads (when referred to the relevant regional reference node via their transmission loss factor) must be less than or equal to the market price cap; and greater than or equal to the market floor price.

A market participant may register a scheduled load to provide any of the frequency control ancillary services (FCAS). Typically a scheduled load is only able to provide the fast (6 second), slow (60 seconds) & delayed (5 minute) frequency raise contingency services, providing a response to a sudden frequency increase through automatic under-frequency load shedding.[96]

Once a market participant has registered a scheduled load for any of these FCAS, the market participant must submit a daily FCAS offer for that service, in a similar format to energy market dispatch bids. The FCAS offer band price is the price (in $/MWh) that the market participant is willing to accept in return for enabling the amount of FCAS MW response within that FCAS offer band.

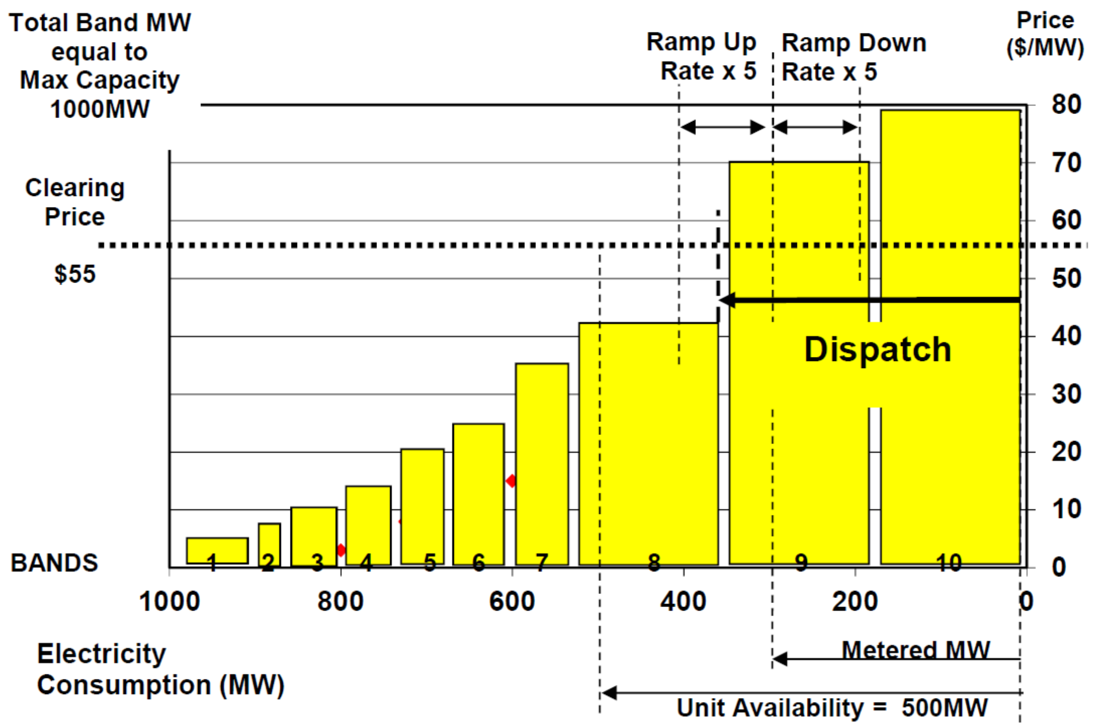
In accordance with NEMDE's objective function (and noting that this is subject to network constraints, power system security requirements and other factors set out in clause 3.8.1):

- generators are dispatched in order from least cost to highest cost until available generation is sufficient to meet demand. By contrast, scheduled loads are dispatched in descending order of price (i.e. those with the highest willingness to pay are dispatched first).
- the energy and FCAS bands of scheduled loads and scheduled generating units are jointly scheduled to determine the least cost/greatest value way of satisfying both the energy demand and FCAS requirements for all regions.

A sample dispatch bid structure for a scheduled load is illustrated below.

96 AEMO, *Guide to scheduled loads*, p. 7.

Figure 6.1: Typical dispatch bid for scheduled load



Source: AEMO, *Guide to scheduled loads*, p. 5.

Based on the above figure, AEMO's *Guide to scheduled loads* includes a worked example which is set out below.

BOX 2: WORKED EXAMPLE - SCHEDULED LOAD DISPATCH BID

In the dispatch bid submitted for this load "X":

Bands 1 to 8 have 620 MW priced below $50/MWh

Band 9 has 190 MW at $70/MWh

Band 10 has 190 MW at $80/MWh

Availability = 500 MW

Ramp up & down Rate = 20 MW/minute

At the start of the dispatch run, the metered MW consumption of load ‘X’ = 290 MW.

The NEMDE solver algorithm then determines the upper and lower limits within which load ‘X’ can be scheduled to consume:

Upper limit = minimum of (Ramp Upper limit, Availability)

= minimum (390, 500)

= 390 MW

where;

Ramp upper limit

= Metered MW + ramp Up rate x 5 mins

= 290 + (20 x 5)

= 390 MW

Lower limit = Ramp lower limit

= Metered MW - Ramp down rate x 5 mins

= 190 MW

The NEMDE solver optimisation then calculates for the trading interval and determines that a market clearing price (dispatch price) for region 'R' of $55/MWh.

As the price of Band 10 is greater than the dispatch price, this band is fully scheduled with consumption of 190 MW. As the price of Band 9 is also greater than the dispatch price, a further 190 MW of consumption is scheduled.

At this stage the total consumption of Bands 9 and 10 = 380 MW which is still within the upper and lower limits determined above. However, the remaining bands are not dispatched at all, as their band prices are all below the dispatch price (that is, the market price was not low enough to justify consumption in those bands).

Therefore, the final scheduled consumption (dispatch target) of load 'X'= 380 MW.

The NEMDE solver algorithm has scheduled an increase in the consumption of the load from 290 MW, dispatching from the higher-priced to lower-priced bands until either the dispatch price falls below the price of the last band dispatched (as in this case) or the scheduled load is constrained to either its upper or lower operating limits.

Source: AEMO, *Guide to scheduled loads*, p. 7.

As the price bands of scheduled loads can be marginally or partially dispatched by the NEMDE solver algorithm, bands so dispatched are able to set the market price (either energy or any FCAS) for a trading interval.[97]

6.2 Should the definition of BidP be amended as proposed by AEMO?

AEMO has requested a change to the definition of "BidP" in the formula for determining compensation for scheduled loads dispatched differently as a result of an intervention event.[98] In particular, AEMO proposes to replace the current definition of BidP ("the price of

97 Ibid, p. 11.

98 See clause 3.12.2(a)(2) of the NER.

the highest priced price band specified in a dispatch bid for the scheduled load in the relevant intervention price trading interval") with a new definition ("the highest priced band the scheduled load is dispatched from").

It is agreed that there is a need to examine this provision, consistent with AEMO's objective of ensuring that scheduled loads are not under-compensated where they are dispatched differently due to an intervention event. However, it is not clear that the solution proposed by AEMO will achieve this objective.

In particular, given that scheduled loads are effectively dispatched in descending order of price (i.e. those with the highest willingness to pay are dispatched first), it follows that whenever a scheduled load is dispatched, the "value of the highest priced band the scheduled load is dispatched from" *is* the"highest price band specified in a dispatch bid" for that scheduled load.

In the example used above, the value of the highest price band the scheduled load is dispatched from is $80/MWh and this is also the highest price band specified in the dispatch bid. This means that changing the rule in the manner proposed would not change the compensation outcome and achieve AEMO's desired objective of avoiding under-compensation.

This seems to suggest that a more appropriate solution would be for compensation to be calculated having regard for the value of the *lowest price band the scheduled load is dispatched from,* i.e. the bid that is closest to the margin. In the above example, the lowest price band the scheduled load is dispatched from is $70/MWh.

Applying these values to the compensation formula in clause 3.12.2(a)(2) illustrates how the change would impact the compensation payable to scheduled loads which are dispatched differently due to an intervention event.

As discussed in chapter 3, the formula used to determine compensation for scheduled loads affected by interventions is:

Compensation per trading interval = ((RRP[99]x LF[100])) - BidP) x QD[101]

Under the current definition of BidP, compensation would be calculated as follows (using the above values and assuming no losses):

Compensation = (($55/MWh x 1) - $80) x QD

Thus, compensation = -$25/MWh x QD

Assuming QD is 50MWh, compensation would be -$1,250.

This would be set to zero in accordance with the definition of QD in clause 3.12.2(a)(2). However, as discussed in chapter 5, there is inconsistency within the NER regarding whether

99 Regional reference price.

100 Applicable loss factor.

101 The difference in energy consumed by the scheduled load as a result of the intervention.

compensation for scheduled loads should be "two way" (as is the case for affected participants[102]) or "one way" (as indicated by the definition of QD in clause 3.12.2(a)(2)). This issue is discussed further in section 6.5.

Using the lowest price band from which the scheduled load is dispatched ($70/MWh), compensation would be determined as follows:

Compensation = (($55 x 1) - $70) x QD

Assuming again that QD is 50MWh, compensation would be -$750. (Again, this would be set to zero in accordance with the current definition of QD.)

If the approach to compensating scheduled loads was "two way" (consistent with the approach to affected participants), the amount to be repaid to AEMO under the above example would be lower (meaning the scheduled load would be better off) if BidP was defined as the lowest price band from which the load is dispatched rather than the highest price band in the bid, or the highest price band form which the load is dispatched.

Using different price bands to those set out in the AEMO worked example, and a different value of QD, compensation payable by AEMO to a scheduled load would also differ depending on how BidP is defined.

In considering the application of this formula, another area of potential uncertainty is how to express QD (being the difference in the amount of electricity consumed v the amount that AEMO considers would have been consumed but for the intervention). AEMO has indicated that it makes this comparison using the difference in dispatch targets from the dispatch run and the intervention pricing run. However the definition of QD does not provide any detail as to whether the value of QD should be expressed as positive or negative.

AEMO has advised the Commission that QD is calculated by taking as the reference point the amount of energy consumed by a scheduled load in the dispatch run of NEMDE (i.e. the amount of energy *actually* consumed by the load during the intervention event). From this, AEMO deducts the amount of energy *hypothetically* consumed in the counterfactual intervention pricing run (i.e. the amount of energy that would have been consumed had the intervention not occurred). Thus QD = dispatch run consumed MW – intervention pricing run consumed MW.

This means that QD is positive when a scheduled load consumes more energy in the dispatch run than in the intervention pricing run and negative when a scheduled load consumes less energy in the dispatch run than in the intervention pricing run.

There may be benefit in clarifying the meaning of QD in the formula set out in clause 3.12.2(a)(2) and stakeholder views are sought on this issue.

102 That is, the scheduled load would be required to repay revenue to AEMO if it was better off as a result of the intervention.

QUESTION 5: HOW TO DETERMINE COMPENSATION FOR SCHEDULED LOADS

Should the definition of BidP in clause 3.12.2(a)(2) be amended to avoid under-compensation of scheduled loads affected by interventions?

If so, how should BidP be defined?

Is there a need to clarify the value of QD in the compensation formula in clause 3.12.2(a)(2)?

Are there any other issues that should inform consideration of this proposal?

6.3 Should scheduled loads be compensated in relation to FCAS as well as energy?

All scheduled loads (pumped hydro and utility scale batteries) can provide market ancillary services in addition to consuming, or refraining from consuming, energy. While the AEMO rule change request seeks to ensure that such participants are not under compensated as a result of the definition of BidP, the rule change request does not address another factor that may cause such parties to be under-compensated: namely, the fact that no compensation is payable to scheduled loads which are dispatched differently with respect to FCAS as a result of an intervention.

Given that scheduled loads can provide FCAS in addition to consuming energy (or reducing consumption), it may be appropriate for the compensation formula to deal with FCAS in addition to energy (consistent with the approach to directed participant compensation and the proposed approach to affected participant compensation). This would appear to be consistent with the cost recovery and settlement provisions discussed in chapter 5 (clauses 3.15.8 and 3.15.10C) which presume that compensation for scheduled load deals with FCAS in addition to energy.[103]

It would also create consistency for pumped hydro and batteries that are currently registered as both generators and market customers, noting that the Commission has a rule change request pending that seeks to integrate energy storage systems into the NEM.[104]

This potential for asymmetric compensation of generation and loads has the potential to result in market distortion. Accordingly, stakeholder feedback is invited on whether the compensation framework for scheduled loads should be amended to take into account

103 For example, clause 3.15.8 deals with funding of compensation for directions. Clause 3.15.8(a)(1)(i) refers to "the total of the compensation payable *to* AEMO *by* affected participants and market customers under clause 3.12.2 in respect of a direction for the provision of energy" (emphasis added). Clause 3.15.8(e)(1)(i) refers to "the total of the compensation payable *to* AEMO *by* affected participants and market customers under clause 3.12.2 in respect of a direction for the provision of that ancillary service" (emphasis added). In both cases, the provisions also refer to compensation paid by AEMO *to* affected participants and market customers, consistent with a two way approach to compensation for both classes of participant. Clause 3.15.10C deals with intervention settlements and adopts the same approach, referring to payments *to* AEMO *by* affected participants and market customers, and payments *by* AEMO *to* affected participants and market customers.

104 That is, when a battery is charging or a pumped storage system is pumping, it is subject to the compensation arrangements pertaining to scheduled loads (with compensation payable in relation to energy only). However, when the battery is discharging, or the hydro generator is generating, it will be compensated as an affected participant (with compensation payable in relation to energy and, if the rules are amended as proposed by AEMO, FCAS). The AEMO rule change request on integrating energy storage is available at https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

impacts resulting from changes in FCAS enablement, as well as changes in the amount of electricity consumed.

> QUESTION 6: SHOULD SCHEDULED LOAD COMPENSATION INCLUDE FCAS?
>
> Should compensation for scheduled loads also include compensation for changes to FCAS enablement targets resulting from an intervention event?

6.4 Should compensation be net of costs incurred or avoided?

When an affected participant is compensated under clause 3.12.2(a)(1), compensation is calculated net of direct costs incurred or avoided in accordance with clause 3.12.2(j)(1).

The calculation of compensation for scheduled loads does not include an equivalent provision to take into account costs incurred or avoided. This could result in overcompensation or under-compensation, and create asymmetry as between generators (compensated as affected participants) and loads (compensated differently to affected participants under the current framework).

If compensation for scheduled loads was to become net of costs incurred or avoided, the kind of costs that should be factored into the calculation of compensation would need to be considered. For example, should the same factors apply as are set out in clause 3.12.2(j)(1) - i.e. fuel costs, incremental maintenance and staff costs?

As discussed in chapter 5, it may also be appropriate to consider FCAS liabilities (scheduled loads are required to contribute to the cost of regulation FCAS having regard for the total energy consumed in a trading interval[105]). If this approach is supported, and subject to considerations of administrative complexity and cost, this factor could be incorporated either through the automatic calculation of compensation under clause 3.12.2(a)(2) or through adjustment claims lodged under clause 3.12.2(f).

> QUESTION 7: SHOULD COMPENSATION FOR SCHEDULED LOADS BE NET OF DIRECT COSTS INCURRED OR AVOIDED?
>
> Do stakeholders consider that compensation for scheduled loads should be net of direct costs incurred or avoided, consistent with the approach to affected participants?
>
> If so,
>
> - what costs should be considered?
> - should some or all of these costs be factored in as part of the automatic calculation of compensation or via the capacity of a market customer with scheduled load to lodge an adjustment claim?

105 AEMO, *Settlements guide to ancillary service payment and recovery*, February 2020, pp 10-11.

6.5 One way or two way compensation for scheduled loads?

AEMO acknowledges that its request to amend the definition of BidP could increase compensation costs to consumers.[106] This in turn raises a question as to whether compensation for scheduled loads should be one way or two way (consistent with the approach to affected participants) given that the latter approach reduces the net cost to consumers and other market participants associated with intervention-related compensation.

AEMO states in its rule change request that scheduled loads receive compensation but do not have to repay AEMO if they are better off as a result of the intervention.[107] By contrast, affected participants (generators and network services) which are dispatched differently as a result of an intervention may either receive compensation (if they are worse off) or be required to repay revenue to AEMO (if they are better off due to the intervention).[108]

This reflects the objective of affected participant compensation as articulated in clause 3.12.2(a)(1): i.e. an affected participant is entitled to receive from AEMO, or must pay to AEMO, an amount that will put the affected participant in the position that the affected participant would have been in had the intervention event not occurred.

It is not apparent why a different approach applies as between scheduled loads and affected participants (generators/network services). As discussed in chapter 5, the cost recovery and settlement provisions set out in clause 3.15.8 and 3.15.10C both presume that compensation to market customers with scheduled loads is a two way process, consistent with the approach to affected participants. Thus there may be an inconsistency between these provisions and clause 3.12.2(a)(2). The wording of clause 3.12.2 also appears to be unclear regarding affected participants' and scheduled loads' entitlement to compensation/liability to repay AEMO. For example, as noted previously in section 3.2.2, there appears to be a tension between the wording of clause 3.12.2(a)(2) and clause 3.12.2(e).

Stakeholder views are sought on the value in adopting a symmetrical approach to compensation for scheduled loads and affected participants - both in relation to the kinds of compensation that should be payable (energy/FCAS) and the approach to compensation (one way/two way). This could reduce the potential for market distortion arising from different treatment of generators and loads, particularly given that both pumped hydro participants and large scale batteries operate in both modes.

Adopting a consistent approach to two way compensation may also reduce inefficient outcomes in terms of compensation costs passed through to other market participants and consumers.[109]

106 AEMO, Rule change proposal, p. 3.

107 ibid.

108 Clause 3.12.2(a)(1).

109 As noted previously, if scheduled loads are entitled to receive compensation but not to pay it, this will increase the "compensation recovery amount" relative to the situation where compensation is payable both to *and by* scheduled loads, consistent with the approach to affected participants.

QUESTION 8: SHOULD COMPENSATION FOR SCHEDULED LOADS BE ONE WAY OR TWO WAY?

Do stakeholders consider that there is value in adopting a symmetrical approach to compensation for scheduled loads and affected participants, such that scheduled loads may receive compensation or be required to repay revenue to AEMO?

7 LODGING A SUBMISSION

Written submissions on the rule change request must be lodged with Commission by 16 July 2020 online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code ERC0284.

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 on rule change requests.[110] 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.

110 This guideline is available on the Commission's website www.aemc.gov.au.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	See AEMC
FCAS	Frequency control ancillary service/s
IPWG	Intervention pricing working group
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM dispatch engine
NEO	National electricity objective
SRD	Settlement residue distribution

A MARKET ANCILLARY SERVICES - AN INTRODUCTION

This appendix provides an introduction to the eight market ancillary services in the NEM, who pays for these services, and recent trends in the cost of these services.

Market ancillary services are defined in chapter 10 of the NER as "a service identified in clause 3.11.2(a)". That provision sets out eight services: fast raise, fast lower, slow raise, slow lower, regulating raise, regulating lower, delayed raise and delayed lower. Together these are known as frequency control ancillary services or FCAS. These services are used by AEMO to maintain the frequency on the electrical system, at any point in time, close to fifty cycles per second as required by the NEM frequency standards.[111]

To maintain frequency within required limits, generation and demand must remain in balance at all times. When generation capacity exceeds demand, frequency will rise. When demand exceeds available generation capacity, frequency will fall.

Frequency control services can be divided into two groups: regulation and contingency. Regulation frequency control can be described as the correction of the generation/demand balance in response to minor deviations in load or generation. Contingency frequency control refers to the correction of the generation/demand balance following a major contingency event such as the loss of a generating unit/major industrial load, or a large transmission element.[112]

Table A.1 below sets out the various market ancillary services used to maintain frequency in response to these different drivers.

Table A.1: **Frequency control ancillary services**

TYPE OF SERVICE	MARKET	FUNCTION
Regulation	Regulation Raise	Regulation service used to correct a minor drop in frequency
	Regulation Lower	Regulation service used to correct a minor rise in frequency
Contingency	Fast Raise (6 Second Raise)	6 second response to arrest a major drop in frequency following a contingency event
	Fast Lower (6 Second Lower)	6 second response to arrest a major rise in frequency following a contingency event
	Slow Raise (60 Second Raise)	60 second response to stabilise frequency following a major drop in

111 AEMO, *Guide to ancillary service markets in the NEM*, April 2015, p. 4.
112 ibid.

TYPE OF SERVICE	MARKET	FUNCTION
		frequency
	Slow Lower (60 Second Lower)	60 second response to stabilise frequency following a major rise in frequency
	Delayed Raise (5 Minute Raise)	5 minute response to recover frequency to the normal operating band following a major drop in frequency
	Delayed Lower (5 Minute Lower)	5 minute response to recover frequency to the normal operating band following a major rise in frequency

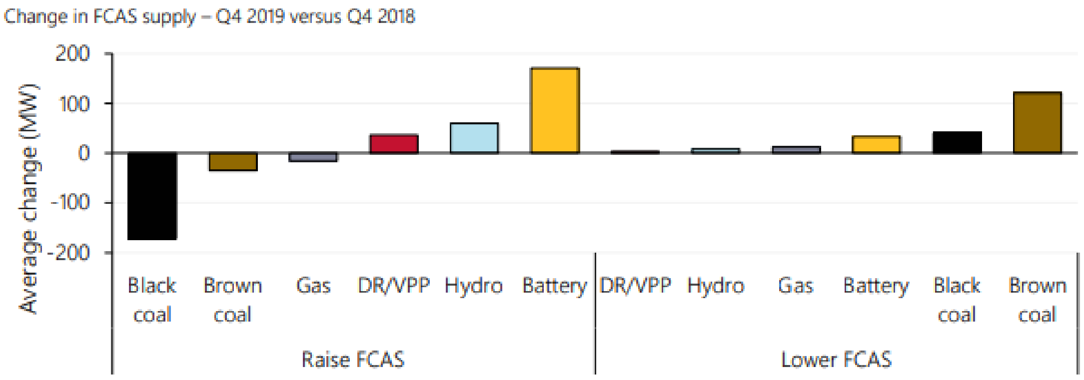
Source: based on AEMO, *Guide to Ancillary Services in the NEM*, April 2015, p. 8.

FCAS cost recovery operates differently depending on the service. For regulation FCAS, scheduled participants have contribution factors determined by the degree to which they follow their dispatch instructions. This requires telemetry that provides AEMO with high granularity information. For participants who do not have this telemetry (typically consumers), it is recovered on a nominal basis of load consumed. For contingency FCAS, the raise costs are apportioned amongst generators and the lower costs are apportioned amongst loads.

Traditionally, synchronous generators have been the predominant providers of FCAS. However, with the creation from mid 2017 of a new type of participant (market ancillary service provider or MASP, which can aggregate consumer loads and participate in the FCAS markets[113]) and increased uptake of utility scale batteries, the FCAS market is now more diverse - as shown by figure A.1. Particularly in South Australia, where a small number of participants had previously exercised considerable market power, this resulted in downward pressure on FCAS prices.

113 AEMC, *Demand Response Mechanism and Ancillary Services Unbundling, Rule Determination*, November 2016.

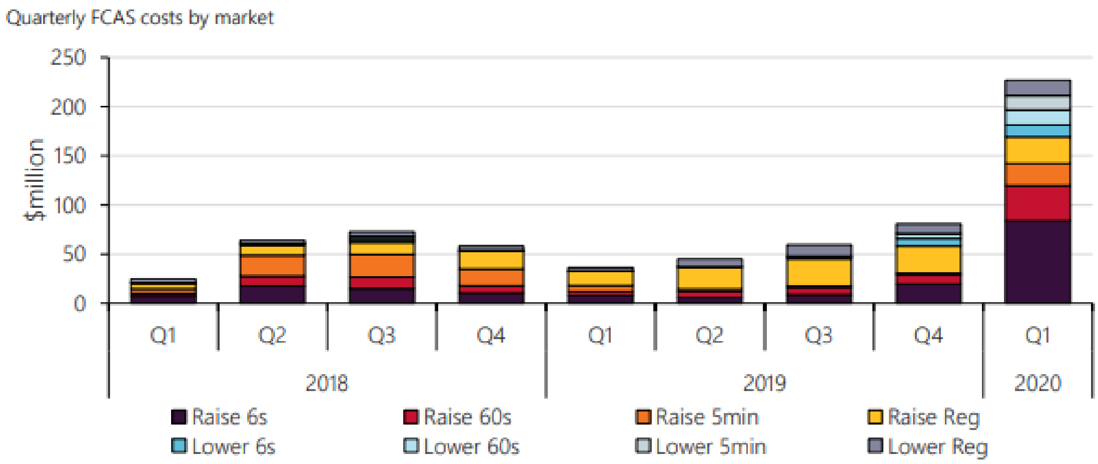
Figure A.1: The changing composition of FCAS markets



Source: AEMO, Quarterly Energy Dynamics, Q4 2019, February 2020, p. 22.
Note: DR = demand response; VPP = virtual power plant

Despite this diversification in the FCAS market, however, FCAS costs are now rising, as shown below in figure A.2. As the generation fleet transitions and the share of non-synchronous generators increases, synchronous generators are operating for fewer hours of the day and some have retired from the market. This has resulted in a decline in the level of inertia and frequency response capability in the system and increasing frequency variations. As a result, FCAS costs are now rising and several rule changes are in progress to address the need for greater frequency control.

Figure A.2: FCAS costs by quarter: Q1 2018 - Q1 2020



Source: AEMO, *Quarterly Energy Dynamics, Q1 2020*, April 2020, p. 25.

The record FCAS costs seen in Q1 2020 were largely due to the extended separation of the South Australian and Victorian power systems following storm damage to the SA-VIC interconnector. In Q1 2020, NEM quarterly FCAS costs increased to record levels of $227 million. Of these costs, $166 million was recovered from generators, with the remainder ($61 million) recovered from retailers. The largest increase in costs by category occurred in the Contingency Raise FCAS markets, which increased from $30 million inQ4 2019 to $142 million in Q1 2020.[114]

114 AEMO, *Quarterly Energy Dynamics, Q1 2020*, April 2020, p. 25.

B SYNERGIES DETERMINATION RE FCAS LOSSES

AEMO's rule change request referred to an unsuccessful compensation claim in respect of FCAS losses which followed interventions in the market in South Australia and Victoria on 1 December 2016.[115] Synergies Economic Consulting was engaged by AEMO to determine the compensation claim. Its final report included a detailed discussion of how clause 3.12.2 (the provision which provides for affected participant compensation) deals with FCAS. An excerpt from the report is set out below.[116]

BOX 3: EXCERPT FROM SYNERGIES' DETERMINATION RE COMPENSATION CLAIM FOR FCAS LOSSES

Clause 3.12.2 sets out how compensation should be determined for Affected Participants. It states, in clause 3.12.2 (a) (1) that the compensation "will put the Affected Participant in the position that the Affected Participant would have been in regarding the scheduled generating unit… had the AEMO intervention event not occurred".

This points towards an assessment based on a comparison of the actual position of the Affected Party with the position they would have been in "but for" the direction. This is supported by clause 3.12.2 (c) which requires AEMO to provide information to the Affected Participant on dispatch in MW that would have occurred but for the direction, the trading amount for that level of dispatch but for the direction, and the actual trading amount. AEMO complied with this requirement in respect of the spot market on 30 December 2017.

Clause 3.12.2 (a) (1) does not precisely codify which of the various possible sources of hypothetical revenue should be considered (i.e. revenue that might have been available to the Affected Participant from the different markets operated by AEMO had the intervention not occurred). Clause 3.12.2 (c) can be construed to require AEMO to supply the estimated level of dispatch of market ancillary services and the estimated trading amount for those ancillary services, but for the direction. For example, the term dispatch used in clause 3.12.2 (c) applies equally to energy or ancillary services, being defined thus:

> The act of initiating or enabling all or part of the response specified in a dispatch bid, dispatch offer or market ancillary service offer in respect of a scheduled generating unit, semi-scheduled generating unit, a scheduled load, a scheduled network service, an ancillary service generating unit or an ancillary service load in accordance with rule 3.8, or a direction or operation of capacity the subject of a reserve contract or an instruction under an ancillary services agreement as appropriate.

To assess whether clause 3.12.2 also extends compensation for foregone ancillary services

115 AEMO, *Rule change proposal - Additional compensation for FCAS losses,* 19 September 2019, p. 3.

116 Synergies Economic Consulting, *Final report on compensation related to directions that occurred on 1 December 2016*, June 2017, pp 34-37.

revenue, it is necessary to examine the specific factors that must be considered in assessing compensation.

The broad objective of clause 3.12.2 set out above would appear to be consistent with compensating Affected Participants for ancillary services revenues they may have foregone as the result of the direction.

However, clause 3.12.2 exhaustively sets out the factors that must be considered in restoring the Affected Participant's position. Specifically, clause 3.12.2 (a)(1) states that 'solely' those items listed in clause 3.12.2 (j) can be considered in an assessment of compensation. The term 'solely' expressly directs that no other factors can be considered in an assessment of compensation. Clause 3.12.2 (j) sets out that the following must, as appropriate, be taken into account:

> (1) the direct costs incurred or avoided by the Affected Participant in respect of that scheduled generating unit or scheduled network service, as the case may be, as a result of the AEMO intervention event including:
>
> (i) fuel costs in connection with the scheduled generating unit or scheduled network service;
>
> (ii) incremental maintenance costs in connection with the scheduled generating unit or scheduled network service; and
>
> (iii) incremental manning costs in connection with the scheduled generating unit or scheduled network service;
>
> (2) any amounts which the Affected Participant is entitled to receive under clauses 3.15.6 and 3.15.6A; and
>
> (3) the regional reference price published pursuant to clause 3.13.4(m).

Clause 3.15.6 sets out the calculation of the trading amount for actual spot market transactions based on the adjusted gross energy, intra-regional loss factor at a connection point, and regional reference price in $/MWh. Essentially, it sets out the amounts owing for generation into the energy spot market within a trading interval. Clause 3.15.6A refers to the calculations of the trading amount for ancillary services, similarly setting out the amounts owing for ancillary services provided by the generator (in this instance) into the ancillary services markets in a trading interval.

Clause 3.15.6A applies to ancillary services. Notwithstanding, Synergies does not consider that reference to this clause can be considered, on its own, to establish that clause 3.12.2 allows for the compensation of foregone ancillary services revenue. [Synergies] base this on the wording of clause 3.12.2 (j) (2) which refers to any amounts which the Affected Participant is entitled to receive.

The entitlement for amounts under clauses 3.15.6 and 3.15.6A derives from the actual provision of energy or ancillary services, not from some hypothetical provision of services as might be estimated in a 'but for' test. Clauses 3.15.6 and 3.15.6A determine trading amounts which result from a transaction. The AEMO's calculation of an estimated trading amount under clause 3.12.2 (c) (1) (ii) (A) does not meet the definition of a transaction. No transaction can reasonably have been said to have taken place as the result of a simulation of a hypothetical set of transactions for the purposes of a 'but for' test. A 'but for' estimation is therefore not an entitlement under clause 3.12.2 (j) (2), so clause 3.12.2 (j) (2) does not extend compensation for foregone ancillary services provision.

In [Synergies'] view, clause 3.12.2 (j) refers to clauses 3.15.6 and 3.15.6A in so far as they are necessary in order to determine the trading amounts that the Affected Party are entitled to from the energy and ancillary services they provided, so as to then determine whether any compensation in excess of these entitlements is warranted. This is particularly important when a claim for compensation indicates that trading amounts under clauses 3.15.6 and 3.15.6A are less than cost incurred as set out in 3.12.2 (j) (1).

The regional reference price is the spot price at the regional reference node, being the price for electricity in a trading interval at a regional reference node or a connection point as determined in accordance with clause 3.9.2. AEMO is obliged to publish this price within 5 minutes of the actual trading interval. Spot price is expressly not an ancillary services price for a market ancillary service, the prices of which are determined in accordance with a different clause 3.9.2A.

Clause 3.12.2 requires consideration of the regional reference price in determining compensation for an Affected Participant, and therefore requires that the spot price for energy is considered. It does not require consideration of ancillary service prices. This indicates that compensation under clause 3.12.2 is confined to foregone spot market revenue or circumstances where costs as defined in clause 3.12.2(j)(1) are greater than trading amounts under cls 3.15.6 and 3.15.6A.

Furthermore, because the factors set out in clause 3.12.2 (j) must be taken into account and are the sole factors that can be considered, clause 3.12.2 should be read to exclude consideration of ancillary services prices in determining compensation. ...

There is some ambiguity in clause 3.12.2 as to whether it allows for compensation for foregone ancillary services revenue. [Synergies] conclude that it does not, for the following reasons:

- the set of criteria that must be considered and which can solely be considered make no express reference to ancillary services prices but do expressly reference spot market prices in the form of the regional reference price. This indicates that compensation is intended to be confined to foregone energy spot market revenues;
- in so far as clause 3.12.2 alludes to ancillary services, it does not do so in a way that indicates an intention to allow for the compensation of foregone ancillary services revenue; and

- the approach that the claimant set out for determining its claim is not confined solely to the factors set out in clause 3.12.2

... In reaching this determination, [Synergies] are mindful that there are ambiguities in clause 3.12.2 that we have had to resolve. It is difficult to determine whether the purpose of clause 3.12.2 is to compensate more generally for foregone revenues or, consistent with other some other compensation clauses in the NER, to ensure that revenues earned by an Affected Participant are not less than the costs that it incurs. If it is the former, it is difficult to determine whether it refers to all possible sources of foregone revenue.

Source: Synergies Economic Consulting, *Final report on compensation related to directions that occurred on 1 December 2016*, June 2017, pp 34-37.