RULE

Australian Energy Market Commission

DRAFT RULE DETERMINATION

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

PROPONENT

AEMO

24 SEPTEMBER 2020

INQUIRIES

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CITATION

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ABOUT THE AEMC

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

SUMMARY

1 The Australian Energy Market Commission (AEMC or Commission) has made a more preferable draft rule which changes the way that compensation is calculated when market participants are dispatched differently as a result of an AEMO intervention event which triggers intervention pricing.[1]

2 This follows two rule change requests from the Australian Energy Market Operator (AEMO) to amend the provisions governing compensation for affected participants and market customers with scheduled loads. These rule change requests both sought to address the risk that such participants will be under-compensated if they are dispatched differently as a result of an intervention event due to issues with the current compensation framework.

3 The Commission invites submissions on this draft rule determination, including the more preferable draft rule, by 5 November 2020.

The interventions framework

4 The interventions framework in the National Electricity Rules (NER) provides AEMO with the tools to intervene in the market for reliability purposes (e.g. in the event of a breach of the reliability standard) or for power system security purposes (e.g. to maintain voltage). Interventions are typically used as a last resort and include, for example, directing a generator to maintain system strength or using emergency reserves through the reliability and emergency reserve trader (RERT).

5 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 as a result of the intervention.

6 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 participants which are dispatched differently due to an intervention event that triggers intervention pricing are put in the position they would have been in but for the intervention.

Intervention pricing

7 When AEMO intervenes in the market by issuing a direction or activating the RERT, it must determine whether intervention pricing should be implemented having regard to a provision known as the "regional reference node (RRN) test".[2]

8 When an intervention is for the purpose of obtaining energy or market ancillary services, intervention pricing is (with some exceptions) used to set prices across the NEM to preserve market scarcity signals that would have existed had the intervention not occurred. Where an intervention is to obtain some other service which is not market-traded (e.g. system strength,

1 "AEMO intervention event" is defined in chapter 10 of the NER as an event where the Australian Energy Market Operator (AEMO) intervenes in the market by issuing a direction in accordance with clause 4.8.9 or exercising the reliability and emergency reserve trader (RERT) in accordance with clause 3.20.

2 This test is set out in clause 3.9.3(b) of the NER.

voltage control or inertia), intervention pricing will not apply as there is no relevant price signal to preserve.

9 AEMO implements intervention pricing by running the national electricity market dispatch engine (NEMDE) twice: once to dispatch the physical market (the "dispatch run") and once to set the price at which the market clears (the "intervention pricing run"). The dispatch run physically dispatches all units (including those directed to provide services) while the intervention pricing run excludes those units directed to provide services. This enables AEMO to estimate the prices for energy and market ancillary services (i.e. frequency control ancillary services or FCAS) that would have applied but for the intervention.

The compensation framework

10 Where AEMO issues a direction, compensation is payable to both directed participants and those participants (i.e. affected participants and market customers with scheduled loads) which are dispatched differently due to the intervention event.[3]

11 An affected participant[4] is entitled to receive from, or required to pay to, AEMO an automatically calculated compensation amount that puts it in the position that it would have been in had the intervention not occurred (providing the absolute value of this amount is greater than $5,000 per intervention event). That is, affected participant compensation is a two-way process.

12 By contrast, market customers with scheduled loads are entitled to receive compensation (again, subject to the $5,000 threshold) but are not required to repay revenue to AEMO. Thus, scheduled load compensation is a one-way process.

13 The amount of compensation payable to such participants is currently calculated by comparing actual generation output or consumption of energy (based on metering data) with the dispatch targets in the intervention pricing run. These dispatch targets signal what the unit would have generated or consumed but for the intervention event.

14 Following this initial, automatic calculation of compensation by AEMO, affected participants and market customers with scheduled load may seek to have their entitlement or liability redetermined (again providing that the value of the claim is greater than $5,000 per intervention event).

15 The cost of both affected and directed participant compensation is recovered from market participants and customers, depending on the nature of the service obtained as a result of the intervention event.[5]

16 At present, compensation paid to affected participants and scheduled loads under clause

3 Clauses 3.15.7 to 3.15.7B and 3.12.2 respectively of the NER.

4 An affected participant is a scheduled generator or scheduled network service provider which was dispatched differently as a result of an AEMO 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.

5 Where the reason for the intervention event is to address a shortage of energy, compensation costs will be recovered from market customers and hence consumers in the region which benefited from the intervention. Where the reason for the intervention is to address a shortage of FCAS, compensation costs will be recovered in line with the normal process for recovering the cost of the FCAS service in question: i.e. from generators, small generation aggregators and/or market customers.

3.12.2 is limited to changes in energy dispatch targets and hence energy revenue (in the case of generators) or energy costs (in the case of scheduled loads). The compensation framework does not include changes to FCAS enablement targets and hence FCAS revenue.

The rule change requests

17 On 19 September 2019, AEMO submitted two rule change requests seeking to change the basis on which compensation is calculated for participants affected by intervention events which trigger intervention pricing. These requests address issues identified by the Intervention Pricing Working Group which was established by AEMO to assist it in reviewing the intervention pricing methodology.

18 The first rule change request sought to address the potential for under-compensation of affected participants by allowing affected participants to claim additional compensation if they incur loss with respect to FCAS.

19 The second rule change request sought to address the potential for market customers with scheduled loads to be under-compensated as a result of the formula used to calculate compensation for such participants (and in particular, the definition of the formula input "BidP").

20 Given that both rule change requests relate to clause 3.12.2 in the NER, the Commission consolidated the requests and progressed them via a single consultation process and rule.

Including FCAS in affected participant compensation

21 The Commission has determined to make a more preferable draft rule that includes FCAS, in addition to energy, in the compensation framework applicable to affected participants. While the AEMO rule change request proposed to enable affected participants to lodge a claim for additional compensation where they have incurred FCAS losses, the more preferable draft rule incorporates FCAS into the automatic process of calculating compensation.

22 This means that affected participants will not need to lodge a claim, and that FCAS compensation – like energy – will be a two-way process. Under this approach, affected participants will both receive compensation where they are worse off with respect to FCAS revenue and be required to repay revenue gains where they are better off with respect to FCAS revenue. This approach is consistent with the objective of affected participant compensation – which is to put the participant in the position it would have been in had the intervention event not occurred.

23 The amount of compensation paid will be the sum of the compensation payable with respect to energy and the compensation payable with respect to FCAS. If the value of one form of compensation is positive and the other negative, the net amount of compensation paid will be lower relative to the status quo. If the value of each form of compensation is positive, compensation costs will increase relative to the status quo.

24 The consultation paper considered whether affected participant compensation should be automatically adjusted to take into account changes in affected participants' FCAS liabilities (resulting from changes in dispatch targets due to an intervention). In light of the complexity of this calculation, the draft rule does not include a provision mandating this process.

However, affected participants may be able to lodge a claim to seek additional compensation if costs are sufficiently material as to exceed the $5,000 threshold.

25 The Commission is mindful of stakeholder concern about increasing compensation costs and has developed some indicative analysis to inform our considerations of what scale of impact the inclusion of FCAS could have on total compensation costs.

26 At the outset, the Commission notes that, since December 2019, affected participant compensation is only payable in connection with intervention events that trigger intervention pricing, and intervention pricing is only used in connection with the RERT and directions to address a shortage of energy or FCAS. Such events are infrequent compared with the large number of security interventions in recent years.

27 The two-way approach to compensation adopted in the draft rule will lower the cost of compensation relative to the approach proposed by AEMO (whereby participants could claim for FCAS losses but would not be required to repay gains).

28 The Commission's analysis of recent intervention events has indicated that FCAS compensation costs for affected participants would likely be small relative to energy compensation costs. Potential FCAS compensation cost impacts would also likely be small when compared with the high cost of FCAS in Q1 2020, which prompted considerable stakeholder concern. It was estimated that including FCAS in the affected participant compensation framework in the first quarter of 2020 would add costs accounting for less than one per cent of the total FCAS costs incurred by the market in Q1 2020.

29 The Commission notes that all other compensation frameworks in the NEM include FCAS and considers that it is appropriate to include FCAS in the compensation framework for affected participants. This is particularly important at a time when the changing composition of the generation fleet is leading to declining inertia levels and a growing need for frequency services.

30 Accordingly, while the Commission recognises that including FCAS in the affected participant compensation framework will have some impact on costs borne by market participants and ultimately consumers, the more preferable draft rule is nonetheless in the long-term interests of consumers since it provides an appropriate allocation of risk and supports the ongoing viability of participants providing important services to the market.

Changing the compensation framework for scheduled loads

31 In addition to including FCAS in the affected participant compensation framework, the draft rule modifies the compensation framework applicable to market customers with scheduled loads. It replicates the compensation objective which currently applies only to affected participants, making clear that the objective of compensation is the same for both affected participants and scheduled loads.

32 The rule change request submitted by AEMO was designed to address the risk that scheduled loads would be under-compensated as a result of the definition of BidP, an input used in the formula for calculating scheduled load compensation. BidP is defined currently as "the price of the highest priced price band specified in a dispatch bid for the scheduled load in the

relevant intervention price trading interval".

33 AEMO proposed to replace this with "the highest priced band the scheduled load is dispatched from" however further analysis revealed that this proposal would not resolve the risk of under-compensation. The Commission's consultation paper explored whether an alternative approach, focusing on the lowest band from which the load is dispatched, would better address the issue identified by AEMO.

34 While several stakeholders supported the AEMC proposal, AGL in its submission to the consultation paper for this rule change suggested that a volume-weighted approach would be preferable. Following further analysis, the Commission has determined that a volume-weighted approach is appropriate and has revised the compensation formula accordingly. The revised formula treats all bid bands independently of one another. This ensures that compensation will be appropriate regardless of the bidding strategy adopted by the scheduled load (i.e. putting a single MW of capacity into a low or high bid band will not skew the outcome since compensation will be calculated with respect to each band separately and then summed).

35 While the consultation paper explored whether scheduled load compensation should be one-way (as currently) or two-way (consistent with affected participant compensation), the Commission has determined that it is appropriate to retain one-way compensation for scheduled loads with respect to energy. This is because scheduled generators and scheduled loads are dispatched differently by NEMDE and adopting a two-way approach to scheduled load compensation would involve calculating compensation for scheduled loads on a "pay-as-bid" basis, where compensation for scheduled generators is calculated based on a "pay-as-cleared" basis. As such, while a two-way approach to scheduled load compensation may appear consistent at face value, further analysis shows that such an approach would introduce inconsistency as to the basis on which compensation is paid.

36 The draft rule also make clear that no compensation will be payable where "QD" (the difference between the amount of energy consumed in the dispatch run and the amount of energy consumed in the intervention pricing run) is negative. This is designed to prevent over-compensation of scheduled loads in anomalous circumstances such as a generator tripping or anomalous intervention pricing outcomes.

37 The Commission acknowledges that the more preferable draft rule may increase the quantum of compensation paid to scheduled loads with respect to energy losses. However, the Commission considers that the revised formula more appropriately allocates risk than does the current formula. In this regard, the Commission notes that the amount of compensation paid to scheduled loads will serve to reduce the amount they would otherwise be required to pay for energy as part of the settlement process. In other words, the energy "compensation" for scheduled loads is a financial transfer designed to re-balance the ledger to make good the fact that the scheduled load would otherwise overpay for the energy it consumed during the intervention event due to the application of intervention pricing.

38 As a result, the revised formula reduces the risk that scheduled loads will, under the current framework, pay more than they should for energy consumed during an intervention event that triggers intervention pricing. The Commission considers that this is both important and

appropriate given the need for significant investment in scheduled load technology to provide dispatchable capacity and system services as the generation fleet transitions.

Including FCAS in the scheduled load compensation framework

39 The draft rule includes FCAS in the scheduled load compensation framework to provide consistency with the proposed approach to affected participant compensation. The Commission notes that generators and loads are dispatched in the same way with respect to FCAS and, as such, a two-way approach to FCAS compensation is appropriate for scheduled loads, consistent with the approach to affected participants.

40 As noted in relation to affected participants, the formula used to calculate compensation will use consistent dispatch target metrics to avoid perverse incentives and provide clarity as to the basis on which scheduled load compensation is to be determined.

41 Finally, the draft rule includes a new provision to make clear that, where two participants are registered with respect to the one unit (as is the case for pumped storage and large scale batteries) and a direction has been issued with respect to that unit, compensation will be payable under the directed participant framework but will not also be payable under clause 3.12.2. This to avoid confusion (which is evident in recent claims for additional compensation) and the potential for double dipping where a unit is both “directed” and “affected” as a result of a direction.

42 The draft rule will not commence immediately as AEMO will need sufficient time to update its internal systems to implement the revised approach to compensating affected participants and market customers with scheduled loads. As well as implementing the changes outlined in this determination, AEMO has an extensive work program underway to implement five-minute settlement and the wholesale demand response mechanism, amongst others. Stakeholder feedback on implementation timing is sought.

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1 AEMO'S RULE CHANGE REQUESTS

1.1 The rule change request

On 19 September 2019, AEMO submitted two rule change requests which 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 which triggers intervention pricing.[6] The rule change requests are:

- *Affected participant compensation for FCAS losses*[7] 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.[8]
- *Compensation for scheduled loads affected by interventions*[9] 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.[10]

Under the NER, an "affected participant" is 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 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 determined that it is appropriate to consolidate the requests and progress them via a single consultation process and rule. Each rule change request is outlined in more detail below.

6 An "AEMO intervention event" is defined in chapter 10 of the NER as an event where AEMO intervenes in the market under the Rules by issuing a direction in accordance with clause 4.8.9 or exercising the reliability and emergency reserve trader (RERT). Intervention pricing is designed to preserve scarcity price signals that would otherwise be muted as a result of the intervention. AEMO implements intervention pricing in accordance with clause 3.9.3(b) of the NER when the reason for the intervention is to address a shortage of energy or market ancillary services.

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

8 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 determination as FCAS. FCAS are used by AEMO to maintain or rebalance the frequency on the power system, at any point in time, close to fifty cycles per second (50 Hz) as required by the NEM frequency operating standards. Further information regarding the eight FCAS markets is provided in Appendix B.

9 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".

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

1.2 Affected participant compensation for FCAS losses

1.2.1 Current arrangements

When an AEMO intervention event triggers intervention pricing, compensation may be payable to those participants which are dispatched differently as a result of the intervention event. This includes both "affected participants" (scheduled generators and scheduled network service providers, as well as eligible persons) and market customers with scheduled loads.

Chapter 10 of the NER defines affected participants as scheduled generators and scheduled network service providers which, (a) were not the subject of a direction or exercise of the RERT, but had its dispatched quantity affected by that direction or exercise of the RERT; or (b) were the subject of a direction or exercise of the RERT, 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.

The class of affected participant which is principally relevant to this rule change request is scheduled generators. This is because scheduled generators provide both energy and FCAS, while network service providers and eligible persons do not provide FCAS.

The objective of affected participant compensation is to put the participant in the position it would have been in but for the intervention.[11] Consistent with this, the compensation framework for affected participants (scheduled generators, scheduled network service providers and eligible persons, but not scheduled loads) is two-way: that is, a participant may be entitled to receive compensation from AEMO if it has been dispatched less as a result of an intervention, or may be required to repay additional revenue earned to AEMO if it is dispatched more as a result of an intervention.

Compensation is calculated by AEMO automatically in the first instance and an affected participant may also submit an adjustment claim if it considers that its entitlement or liability should be redetermined.[12] AEMO calculates compensation by deducting the trading amount that the affected participant *did* receive (as set out in its final statement) from the trading amount that the affected participant *would have* received based on the targets in the intervention pricing run.[13]

The intervention pricing 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.

When an intervention event brings on additional capacity or reduces demand, the prices produced by the intervention pricing or "what-if" run will generally be higher than those produced by the dispatch run. This is because the what-if run will continue to signal the price

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

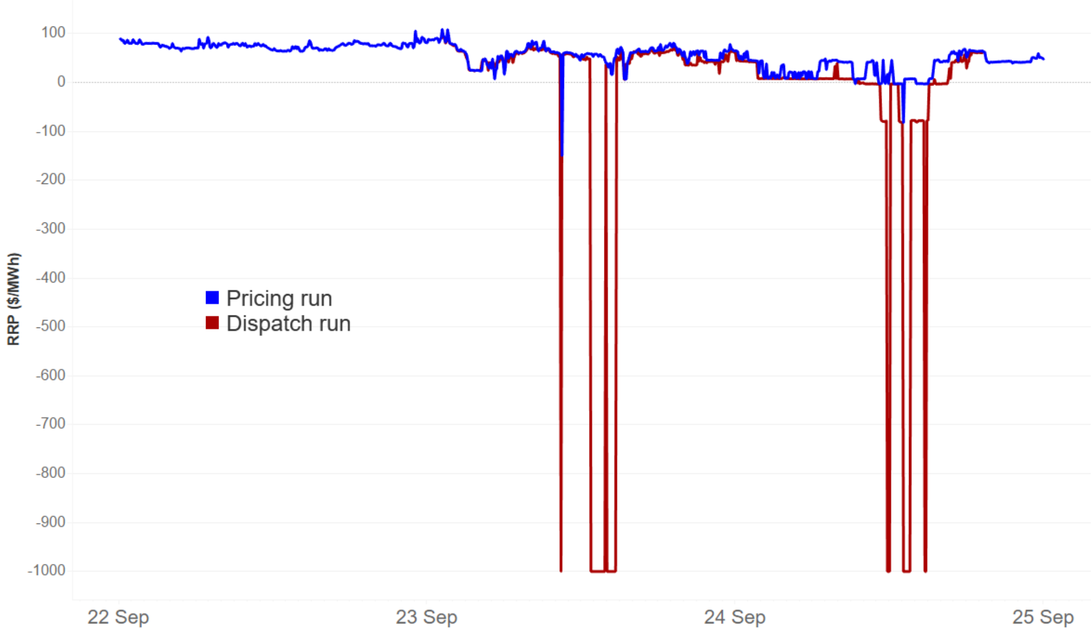
12 Clause 3.12.2(f) of the NER.

13 Clause 3.12.2(c)(1) of the NER.

associated with the supply demand balance as it was prior to the intervention, while prices in the dispatch run will generally be lower due to the addition of generation capacity or the reduction of demand (due to activation of the RERT).

This is not to say that the spot price is being pushed up by the intervention. Rather, intervention pricing is not allowing the price to fall in response to the additional generation coming online or the reduction in demand. This effect can be seen in figure 1.1 which shows that the commencement of a direction issued in September 2017 did not result in spot prices rising. However, the use of intervention pricing means that the spot price in the what-if run does not fall (as it does in the dispatch run - shown in red) in response to additional generating capacity coming online.

Figure 1.1: Intervention pricing's impact on SA prices, 22-25 September 2017



Source: AEMC, *Investigation into intervention mechanisms and system strength in the NEM, Consultation paper, 4 April 2019*, p. 48.
Note: It is noted that intervention pricing no longer applies in connection with system strength directions.

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

- direct costs incurred or avoided by the affected participant as a result of the intervention event, specifically including (but not limited to): 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 published regional reference price (being the price of electricity).

The Intervention Pricing Working Group (IPWG) identified that this clause currently excludes FCAS prices from the items listed. As a result, affected participant compensation has to date only been paid with respect to changes in energy dispatch targets and thus energy revenue resulting from an intervention event. No compensation is payable where a participant is dispatched differently with respect to FCAS as a result of an intervention. On the one occasion that an affected participant lodged an adjustment claim seeking compensation for FCAS losses, this claim was rejected by the independent expert engaged to determine the claim.[14]

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

A generator in South Australia made a claim for additional affected participant compensation following 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 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 4 and Appendix C.

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

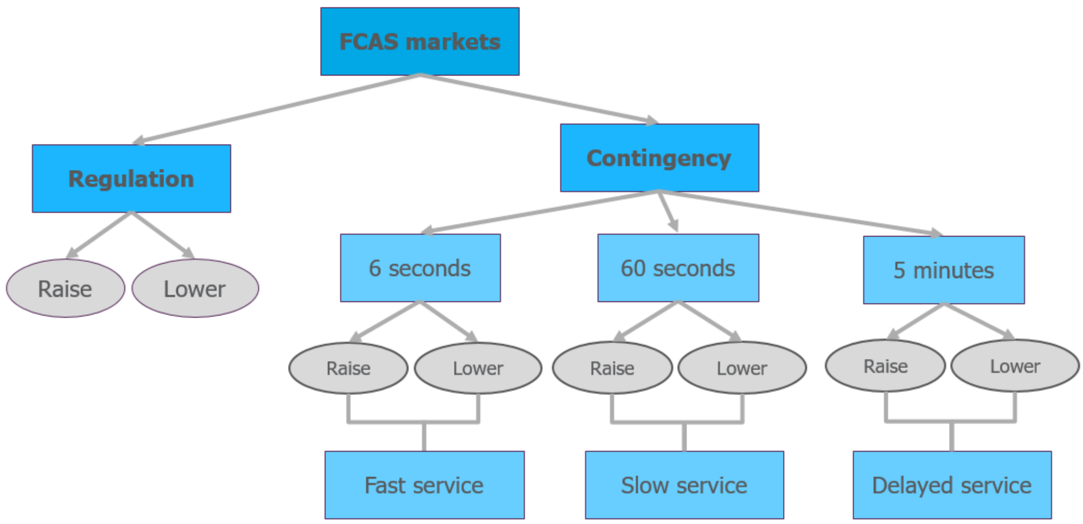
By contrast, other compensation frameworks in the NER do provide for compensation to be paid with respect to FCAS. They include the directed participant compensation framework, the market suspension compensation framework and the administered price period compensation framework. Further detail regarding these frameworks is set out in Appendix D.

14 Synergies Economic Consulting Pty Ltd, *Final report on compensation related to directions that occurred on 1 December 2016*, June 2017.

1.2.2 Rationale for the rule change request

In its rule change request, AEMO seeks to address this gap by allowing affected participants to make an adjustment claim to seek compensation with respect to FCAS losses. There are eight FCAS services as shown in 1.2: two for regulation services and six for contingency services.

Figure 1.2: The eight FCAS markets



Source: AEMO, *Settlements guide to ancillary services payment and recovery,* February 2020, p. 6.

Regulation frequency control can be described as the correction of the generation/demand balance in response to minor deviations in load or generation.[15] Regulation raise providers add MW to the system in order to raise the frequency closer to 50 Hz while regulation lower providers take MW out of the system in order to lower the frequency closer to 50 Hz.

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.[16]

AEMO noted 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 growing and affected participants' lost FCAS revenue is increasingly likely to become material. As a result, AEMO noted the current compensation rules are unlikely to meet the objective of putting the participant in the position it would have been in but for the intervention.

Accordingly, AEMO considered 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. It

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

16 ibid.

considered that this achieves a "fairer outcome" for affected participants that may be negatively impacted by FCAS losses resulting from an intervention event.[17]

1.2.3 Solution proposed in the rule change request

To address this issue, AEMO proposed to include FCAS prices amongst the compensable factors to be considered in determining additional compensation under clause 3.12.2(j).

The rule change request included 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 4.

1.3 Compensation for scheduled loads affected by interventions

1.3.1 Current arrangements

As with affected participants, market customers with scheduled loads are entitled to compensation if they are dispatched differently as a result of an intervention event which triggers intervention pricing.[18] AEMO calculates compensation automatically in the first instance in accordance with a formula set out in clause 3.12.2(a)(2). A market customer may also lodge a claim for additional compensation with respect to its scheduled load if it considers that the initially calculated compensation was inadequate.

Scheduled load is defined in Chapter 10 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."[19]

Scheduled loads are 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.[20]

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).[21] This will likely change as more utility scale batteries are installed - see figure 1.3 for projected uptake to 2025.

17 AEMO, Rule change proposal, p. 3.

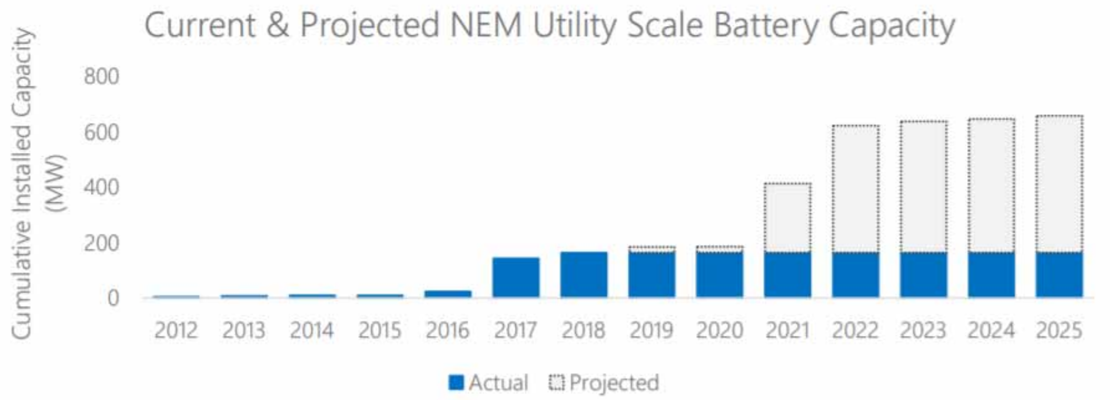
18 Clause 3.12.2(a)(2).

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

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

21 AEMO, NEM registration and exemption list, available at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/registration. It is noted that batteries and pumped hydro are required to register as both loads and generators.

Figure 1.3: 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.[22] This is one of a number of factors set out in the compensation formula in clause 3.12.2(a)(2).

AEMO notes that it has seen an increase in the amount of compensation paid (see figure 1.4) as a result of the increase in directions required in the NEM, especially in South Australia, where there is utility scale battery load[23] and where well over 400 system strength directions have been issued in the period since April 2017

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 and AEMO considers this may be due to the application of the $5,000 per trading interval compensation threshold which applied until December 2019.

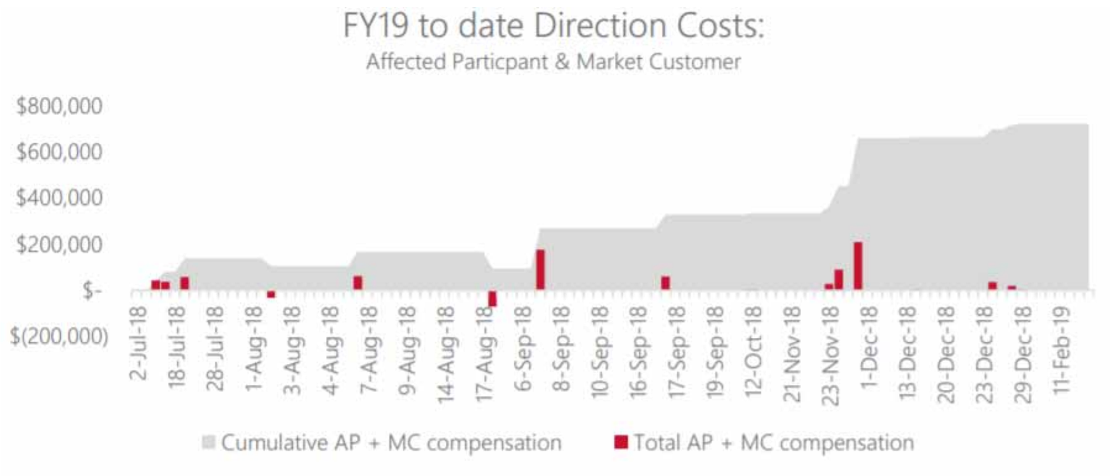
Prior to December 2019, affected participants and market customers with scheduled loads were not eligible for compensation in respect of amounts less than $5,000 per trading

22 As with affected participants, this is done by comparing the scheduled load's actual consumption of energy during the intervention event with the amount of energy it would have consumed but for the intervention, based on the dispatch targets in the intervention pricing run.

23 AEMO, Rule change proposal, p. 2.

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.[24]

Figure 1.4: 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 earlier, 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, interventions to address a shortage of energy or FCAS still trigger such compensation payments.

Compensation costs associated with recent RERT activations are shown below.

24 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.

Table 1.1: 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.[25]

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

$$DC = ((RRP \times LF) - BidP) \times QD$$

where

- DC (in dollars) is the amount the market customer is entitled to receive in respect of that scheduled load for the relevant intervention price trading interval
- 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"[26]
- 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"

25 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.

26 Price band is defined in Chapter 10 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".

provided that if DC is negative for the relevant intervention price trading interval, then the adjustment that the market customer is entitled to claim in respect of that scheduled load for that intervention price trading interval is zero.

1.3.2 Rationale for the rule change request

AEMO was concerned 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.[27]

In particular, AEMO considered 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 noted that it has not observed instances of compensation for scheduled loads being affected by this rule, and considered 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.[28]

1.3.3 Solution proposed in the rule change request

AEMO's rule change request proposed 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.

AEMO considered 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".[29]

AEMO acknowledged that the proposed change may increase the quantity of compensation payable by market customers and ultimately by consumers.[30] However, AEMO considered that the impact on compensation costs would be "comparatively minimal" given the small amount of scheduled load currently in the market. It also considered 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 considered that the proposed changes strike a fair balance between the interests of market participants and consumers".[31]

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

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

28 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.

29 AEMO, Rule change proposal, p. 4.

30 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).

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

1.4 The rule making process

On 11 June 2020, the Commission published a notice advising of the consolidation of the two rule change requests submitted by AEMO, and of its commencement of the rule making process and consultation in respect of the consolidated rule change request.[32] A consultation paper identifying specific issues for consultation was also published. Submissions closed on 16 July 2020.

The Commission received ten submissions as part of the first round of consultation. The Commission considered all issues raised by stakeholders in submissions. Issues raised in submissions are discussed and responded to in relevant sections of this draft rule determination.

1.5 Consultation on draft rule determination

The Commission invites submissions on this draft rule determination, including the more preferable draft rule, by 5 November 2020.

Any person or body may request that the Commission hold a hearing in relation to the draft rule determination. Any request for a hearing must be made in writing and must be received by the Commission no later than 1 October 2020.

Submissions and requests for a hearing should quote project number ERC0284 and may be lodged online at www.aemc.gov.au.

32 This notice was published under s.95 of the National Electricity Law (NEL).

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)[33], directions and instructions.[34] 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.[35] 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.[36] Intervention pricing is a transparent process that sends clear signals to the market, in terms of both operational and investment timescales.

33 Rule 3.20 of the NER.

34 Clause 4.8.9 of the NER.

35 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.

36 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 units 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 scheduled network service providers 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 clauses 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 claims exceeds a compensation threshold of $5,000 per direction.[37]

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.[38]

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.[39]

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

38 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.

39 AEMO, *Rule change proposal: Affected participant compensation for scheduled loads*, September 2019, p. 1.

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 (combined with metered output/consumption) and their dispatch targets from the 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.[40]

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.[41] 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.[42]

The application of the compensation framework lacks transparency: for example, no data about individual compensation payments is made public unless an independent expert has been engaged to determine the amount of compensation payable (e.g. under clause 3.15.7A) or there is an additional compensation claim under clause 3.12.2(f) or clause 3.15.7B with a value in excess of certain thresholds.[43] 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, there have been increasing concerns about reliability. 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 540 directions have been issued by AEMO. [44] The majority of these 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

40 See clause 3.12.2(i) of the NER.

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

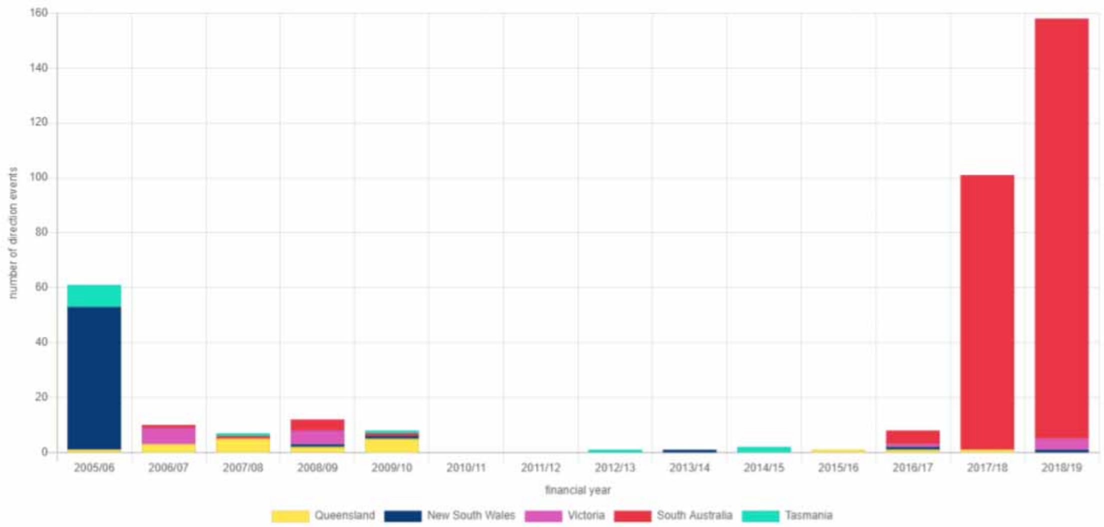
42 See clause 3.15.8(e) and (f) which in turn refers to the cost recovery formulae for market ancillary services set out in clause 3.15.6A of the NER.

43 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.

44 Data provided by AEMO as at 30 June 2020.

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 transmission towers on 31 January 2020 due to a severe storm. South Australia and Victoria were re-connected on 17 February 2020.[45]

Figure 2.1: Directions issued by AEMO in last decade



Source: Reliability Panel, *2019 Annual Market Performance Review, Final report*, 12 March 2020, p. 147. AEMC analysis of data provided by AEMO.

By contrast, reliability directions occur infrequently with only five reliability directions issued in the period since 2010. [46] 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).[47]

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

46 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.

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

There are three types of RERT based on how much time AEMO has to procure the RERT prior to the projected reserve shortfall occurring. These are:

- The interim reliability reserve which replaces long-notice RERT on a temporary basis (which provided for between ten weeks' and twelve months' notice of a projected reserve shortfall). On 19 August 2020 the Energy Security Board (ESB) published a set of changes to the National Electricity Rules (Rules) to establish an out of market capacity reserve (the interim reliability reserve). The interim reliability reserve delivers further reliability by establishing an interim out-of-market capacity reserve and amending triggering arrangements for the Retailer Reliability Obligation (RRO). These measures would allow AEMO to procure reserves for contract terms of up to three years, replacing the long notice RERT until 2025. They aim to keep unserved energy to no more than 0.0006% in any region in any year.[48]
- medium-notice RERT: between ten weeks' and one week's notice of a projected reserve shortfall.
- short-notice RERT: less than seven days' notice of a projected reserve shortfall.

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.[49]

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.[50] 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.

48 COAG Energy Council, Energy Security Board, Interim Reliability Reserve - decision paper, July 2020.

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

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

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 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.[51] 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 made two further recommendations which are the focus of this determination:

1. changing the manner in which compensation is calculated for market customers with scheduled loads which are dispatched differently as a result of an intervention event
2. including FCAS losses in the list of factors that can be considered when determining additional compensation claims by affected participants.

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.[52]

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.[53]

A number of recommendations in the *Interventions investigation final report* have already been actioned. These include the following rule changes, three of which were made on 19 December 2019 and two of which were made on 10 September 2020. The first two rule change below have particular importance for this determination.

- Changes to the regional reference node 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".[54] Under

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

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

53 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.

54 Meaning activation of the RERT or issuance of directions.

the revised RRN test, intervention pricing is now implemented where an AEMO intervention event is for the purpose of obtaining a service for which there is a market price.[55] Where the purpose of an intervention is to obtain a service for which there is no market price,[56] intervention pricing does not apply. This recognises that, in such circumstances, there is no relevant market price signal to preserve.[57]

- Changes were also made to the circumstances in which compensation is paid to participants dispatched differently as a result of an intervention event. Under the revised approach, such compensation is only payable in circumstances where an AEMO intervention event triggers intervention pricing in accordance with the revised RRN test.[58] This is an important development when considering the matters in this determination, noting that the rule change requests dealt with in this determination were submitted prior to the making of the December 2019 rule. As a result of narrowing the circumstances in which such compensation is payable, the rule changes proposed by AEMO affect a narrower set of intervention events - namely, those which trigger intervention pricing - and will have no impact on security interventions[59], which are far more common than interventions to address a shortage of energy or FCAS.
- 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.[60]
- On 10 September 2020, the Commission made a final rule to change three elements of the interventions framework in the NER. In particular, the rule:
  - removed the mandatory restrictions framework set out in rule 3.12A of the NER
  - removed the requirement on AEMO to use “counteractions” in order to confine the impact of an intervention event to a single region and, if possible, a single participant
  - formalised the arrangements for apportioning and recovering compensation costs following RERT activations, thereby addressing a gap in the NER.[61]
- Also on 10 September 2020, the Commission made a final rule to remove the intervention hierarchy set out in clause 3.8.14. This prescriptive hierarchy required AEMO, during conditions of supply scarcity, to activate the RERT first and then if necessary issue directions or clause 4.8.9 instructions. The Commission determined that this could result in higher than necessary costs to consumers and should be replaced with a principle of

55 That is, energy or market ancillary services, or a service which is a direct substitute for these.

56 For example, voltage control or system strength.

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

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

59 In this determination, the phrase “security interventions” refers to those interventions to obtain security services other than FCAS.

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

61 AEMC, *Changes to intervention mechanisms, Rule determination,* 10 September 2020.

using the intervention mechanism, or combination of mechanisms, that is effective while minimising direct and indirect costs.[62]

2.4 Other intervention related rule change request

AEMO has also submitted a request to change 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 under clause 3.15.7B and making the compensation process a one-step rather than two-step process under clause 3.15.7A.

A draft determination was published on 24 September 2020 and a final determination is expected in December 2020.[63]

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 determination - 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 and provide a framework that supports their participation and business models where there is a mix of technology types connecting behind a connection point.[64] 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.

A consultation paper on this rule change request was published in August 2020, and explores whether any additional changes to compensation frameworks are required in order to accommodate bi-directional resource providers.[65] The Commission will continue to coordinate work on the integrating storage rule change request with the requests which are the subject of this determination.

62 AEMC, *Removal of intervention hierarchy, Rule determination*, 10 September 2020.

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

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

65 AEMC, *Integrating Energy Storage Systems into the NEM, Consultation paper*, 20 August 2020.

In particular, the integrating storage rule change request is relevant to the question of how to compensate market customers with scheduled loads.[66]

As set out in the integrating storage 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.[67]

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. 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 considerations regarding FCAS liabilities in relation to the rule change requests discussed in this determination are outlined in chapters 4 and 5.

2.5.3 Post 2025 market design

In March 2019, the COAG Energy Council (now the ministerial forum of Energy Ministers) 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

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

67 ibid, p. 23. "What-if" pricing is another name for intervention pricing, hence the reference to "what-if scenarios" which are used to calculate compensation for participants dispatched differently as a result of an intervention.

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 as a pathway to a fit for purpose market design for the NEM. The ESB will provide advice to Energy Ministers on changes to the existing market design, or recommend an alternative market design, to enable the provision of the full range of services to customers necessary to deliver a secure, reliable and lower emissions electricity system at least cost by mid-2021.

There are seven core market design initiatives being progressed:[68]

- **Resource adequacy mechanisms:** the focus of this work is on whether existing mechanisms are sufficient to support the changing needs of the system (particularly new investment) in the next 10-15 years, or whether other complementary measures are needed.
- **Ageing thermal generator strategy:** there are a number of existing measures that would reduce uncertainty around the timing of exit of ageing thermal generation in the NEM over the coming decades.[69] The ESB will consider whether additional measures are needed during the transition period as thermal generators retire.
- **Essential system services:** the focus of this work is to develop a framework to enable the market to progress to more sophisticated ways to deliver system services as the system changes, and as technology and market conditions allow.
- **Scheduling and ahead mechanisms:** In 2025, the system is expected to be more complex, with variable and changing patterns of demand and supply creating challenges to keep the system balanced. Changes to market arrangements are being considered that introduce greater visibility and certainty of resources in the system ahead of real time.
- **Two-sided markets:** A two-sided market is a market model that promotes direct interaction between suppliers and customers. The focus is on getting the market framework right to accommodate different customer needs and provide appropriate customer protections for consumers. The intention is a progressive shift to a two-sided market that better rewards the value provided to the system by flexible demand and supply.
- **Valuing demand flexibility and integrating Distributed Energy Resources (DER):** to maximise the value of DER for consumers, there is a need for technical, regulatory and market arrangements to support their effective integration.
- **Transmission access and the coordination of generation and transmission investment:** the shift to locate generation in different places is a challenge for the existing transmission network, connections to it, and how it is accessed and used. A combination of regulatory and market arrangements are needed to support efficient and timely investment to deliver efficient outcomes to consumers and investors.

68 Energy Security Board, Post 2025 Market Design Consultation Paper, September 2020.

69 These include measures to ensure that essential system services are available, the 42 month notice of closure, and the Retailer Reliability Obligation.

The next phase of the ESB Post 2025 work program is to evaluate potential solutions. Options for future market design will be developed with input from stakeholders, with design options released for consultation around late December 2020 or early 2021.

There are interactions between these workstreams and the interventions work program. The Commission and the ESB as well as the AER and AEMO are coordinating on these pieces of work. For example, in the recent consultation paper on the scheduling and ahead mechanisms workstream, the ESB noted its support for implementing a unit commitment for security (UCS) approach to support scheduling system services under contract (rather than a spot market) and systemise how AEMO issues directions to market participants to provide greater certainty. This would aim to provide confidence that critical resources will be available to deliver secure and reliable electricity supply in real-time.[70]

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 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 for such ad hoc directions.

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.[71]

These rule changes complement and are interdependent with the issues being explored by the ESB in its ongoing post-2025 market design program. The AEMC is working closely with the ESB and other market bodies, particularly AEMO, on these rule change requests. The rule changes provide us with an opportunity to complement the thinking and assessment done in the ESB work program. It allows us to address the issues in a cohesive way, as well as addressing system security issues that are more urgent in nature.

70 ibid, p. 74.

71 AEMC, *System services rule changes, Consultation paper*, 2 July 2020.

3 DRAFT RULE DETERMINATION

This chapter sets out the Commission's draft determination with a summary of reasons. Commission considerations described in chapters 4 and 5 provide additional details supporting the Commission's decision.

This chapter outlines:

- the rule making test for changes to the NER
- the more preferable rule test
- the assessment framework for considering the rule change request
- the Commission's consideration of the more preferable draft rule against the national electricity objective.

3.1 The Commission's draft rule determination

The Commission's draft rule determination is to make a more preferable draft rule. The more preferable draft rule amends the compensation framework in clause 3.12.2 to include FCAS in the compensation payable to both affected participants and market customers with scheduled loads, and amends the formula used to compensate scheduled loads with respect to energy costs to address risks of both under and over-compensation. Further information on the elements of the more preferable draft rule is set out below.

The Commission's reasons for making this draft determination are set out in section 3.4.

Further information on the legal requirements for making this draft rule determination is set out in Appendix A.

3.1.1 Affected participant compensation for FCAS

The more preferable draft rule includes FCAS, in addition to energy, in the automatic calculation of affected participant compensation under clause 3.12.2(c)(1). This means that, with respect to both energy and FCAS, affected participants will be put in the position they would have been in but for the intervention event: that is, affected participants will be eligible for compensation when they are worse off as a result of an intervention event which triggers intervention pricing, or required to repay gains when they are better off as a result of the intervention event.

To achieve this, a new subparagraph has been added to clause 3.12.2(c)(1) requiring AEMO to advise the participant of the estimated level at which an ancillary service generating unit would have been enabled to provide FCAS if the intervention event had not occurred (based on the enablement targets in the intervention pricing run) and the resultant trading amount based on these targets. AEMO then deducts from this the trading amount based on the enablement targets in the dispatch run.

Compensation payable to or by affected participants will be the sum of compensation calculated with respect to energy revenues, and compensation calculated with respect to

FCAS revenues. Thus, if one compensation value is positive and the other negative, the amount of compensation paid will be the net amount derived from these two components.[72]

In contrast to the AEMO proposal, affected participants will not need to lodge an adjustment claim in order to receive FCAS compensation because compensation is calculated automatically in accordance with clause 3.12.2(c)(1). However, as proposed in the AEMO rule change request, the draft rule also includes a reference to market ancillary service prices in clause 3.12.2(j). This will allow affected participants to lodge adjustment claims if they wish to have their compensation or liability with respect to FCAS re-determined following receipt of automatically calculated compensation.

The consultation paper considered whether affected participant compensation should be automatically adjusted to take into account changes in affected participants' FCAS liabilities resulting from changes in dispatch targets due to an intervention. In light of the complexity of this calculation, the draft rule does not include a provision mandating this process. However, paragraph (j) allows participants to seek additional compensation with respect to direct costs incurred or avoided as a result of an AEMO intervention event. Such a claim could seek compensation with respect to FCAS liabilities if these are sufficiently material as to exceed the $5,000 compensation threshold set out in clause 3.12.2(i).

The draft rule also amends the basis on which affected participant compensation is calculated so that the amount of compensation is no longer determined based on metered generation output during an intervention event. Instead, compensation will be determined by comparing the:

- affected participant's dispatch targets in the dispatch run used to dispatch market participants when intervention pricing is being implemented with
- the affected participant's dispatch targets in the intervention pricing run used to set the price at which the market clears when intervention pricing is being implemented.

This provides for compensation to be calculated based on consistent metrics, makes clear that a participant is not "affected" and no compensation is payable where the dispatch targets in the two runs are identical, and removes the potential for a participant to receive compensation because it has not followed dispatch targets. To achieve this change, as noted above, existing clause 3.12.2(c)(1)(ii)(B) has been amended so that it no longer refers to the trading amount set out in the affected participant's final statement and instead refers to the trading amount determined by AEMO based on the dispatch targets in the dispatch run.

Finally, the draft rule amends clause 3.12.2(a)(1) so that it no longer refers to determining affected participant compensation "taking into account solely the items listed in paragraph (j)". Instead, the draft rule refers to compensation being determined by reference to the amounts determined in accordance with subparagraphs (c)(1) and (c)(2) and the items listed in paragraph (j). This amendment reflects that affected participant compensation is determined in large part based on the process set out in paragraph (c), and this process is not referenced in paragraph (j). As such, the current wording of clause 3.12.2(a)(1) is

72 As per current clause 3.12.2(b), no compensation is payable to or by an affected participant if the amount is less than $5,000.

inaccurate and creates uncertainty. [73] The same approach is adopted in clause 3.12.2(a)(2) with respect to scheduled loads.

Further detail on the more preferable draft rule can be found in chapter 4.

3.1.2 Compensation for scheduled loads

The draft rule replicates in clause 3.12.2(a)(2) the compensation objective set out in subparagraph (a)(1) - namely, that the objective of compensation is to put the market customer (in respect of one or more of its scheduled loads) in the position it would have been in regarding the scheduled load but for the intervention event. This provides clarity and consistency as between affected participants and market customers with scheduled loads.

The formula (including the definition of BidP) used to calculate scheduled load compensation is amended so that compensation is based on a volume-weighted approach, rather than focusing on a single bid band. The draft rule also relocates the formula from subparagraph (a)(2) to subparagraph (c)(3), creating consistency with the provisions relating to compensation for affected participants and making clear that, as with affected participants, the amount of compensation to be paid to or by a scheduled load will be the sum of its energy and FCAS compensation (see further below).

The formula is also amended so that compensation is determined by comparing:

- the scheduled load's dispatch targets in the dispatch run used to dispatch market participants when intervention pricing is being implemented with
- the scheduled load's dispatch targets in the intervention pricing run used to set the price at which the market clears when intervention pricing is being implemented.

As noted above in relation to affected participants, this provides for compensation to be calculated based on consistent metrics, makes clear that no compensation is payable where the dispatch targets in the two runs are identical, and removes the potential for a scheduled load to receive compensation because it has not followed dispatch targets.

The formula used to calculate scheduled load compensation retains the current provision stating that where "DC" (the value of scheduled load compensation with respect to energy costs) is negative, this value will be set to zero. This means that a one-way approach to scheduled load compensation will be retained with respect to energy costs. However, the draft rule also provides that, where "QD" (the difference between the amount of electricity consumed in the dispatch run and the amount of electricity which would have been consumed in the intervention pricing run) is negative, a scheduled load is not required to repay revenue to AEMO.

QD will be negative if AEMO estimates that the scheduled load would have consumed more energy in the intervention pricing run than in the dispatch run. Such outcomes would only occur in anomalous circumstances, such as the scheduled load tripping (meaning that the

73 While paragraph (j) does refer to amounts which the affected participant is entitled to receive under clauses 3.15.6 and 3.15.6A, these amounts are trading amounts and thus do not encompass the process of determining what amounts would have been received "but for" the intervention event. This was a point recognised by Synergies Economic Consulting when it determined that it was not possible to pay affected participant compensation with respect to FCAS losses: see Synergies Economic Consulting, *Final report on compensation related to directions that occurred on 1 December 2016*, June 2017, discussed in Appendix C.

dispatch targets in the pricing run are higher than those in the dispatch run) or when the intervention price is lower than the dispatch run price.[74]

The draft rule includes FCAS in the compensation for scheduled loads. Consistent with the approach adopted in relation to scheduled generators (i.e. affected participants), FCAS compensation for scheduled loads will be a two-way process, involving both compensation for loss and a requirement to repay gains. This two-way approach to compensation is appropriate given that generators and scheduled loads are dispatched in the same way with respect to FCAS (unlike energy).

Under clause 3.12.2(f), an affected participant or market customer with scheduled load can seek a re-determination of its entitlement to compensation as determined by AEMO.[75] In the case of affected participants, existing clause 3.12.2(a)(1) provides that the determination of compensation under paragraph (a)(1) is to take into account solely the items listed in paragraph (j). However, subparagraph (a)(2) - relating to market customers - does not reference paragraph (j).

To address this, and increase consistency between affected participants and market customers, the draft rule amends paragraph (a)(2) so that it includes a reference to paragraph (j). As noted earlier, the draft rule also amends paragraph (a)(2) to make clear that compensation for scheduled loads is to be determined having regard to both the process set out in subparagraph (c)(3), dealing with changes in energy and FCAS revenue, and the items listed in paragraph (j).

The draft rule also amends paragraph (j) so that it refers to market customers and scheduled loads (in addition to affected participants and scheduled generating units etc). This will enable market customers with scheduled loads to seek a re-determination of their compensation amount, or claim additional compensation, having regard for the items listed in paragraph (j) - for example, direct costs incurred or avoided as a result of the AEMO intervention event.

The consultation paper considered whether scheduled load compensation should be automatically adjusted to take into account changes in affected participants' FCAS liabilities (resulting from changes in dispatch targets due to an intervention). In light of the complexity of this calculation, the draft rule does not include a provision mandating this process. However, paragraph (j) allows market customers with scheduled loads to seek additional compensation with respect to direct costs incurred or avoided as a result of an AEMO intervention event. Such a claim could seek compensation with respect to FCAS liabilities if these are sufficiently material as to exceed the $5,000 compensation threshold set out in clause 3.12.2(i).

To prevent the payment of more compensation than is appropriate and efficient, the more preferable draft rule includes a new paragraph in clause 3.12.2(b1) to prevent the payment of both directed participant compensation and compensation under clause 3.12.2 with

74 Typically the intervention price will be higher than the dispatch run price.

75 AEMO determines compensation in accordance with clause 3.12.2(a)(1) for affected participants and clause 3.12.2(a)(2) for market customers with scheduled loads.

respect to a single unit (e.g. a large scale battery or pumped hydro plant) which is registered as both a scheduled generator and scheduled load. This makes clear that, where two different kinds of participants are registered with respect to the one unit, compensation is not payable under both the directed participant compensation framework and the compensation framework for affected participants and scheduled loads dispatched differently due to an intervention. Given the inclusion of this new provision, the draft rule also deletes clause 3.15.7B(a3)(7) - a provision which is unclear, has proved difficult to apply in practice, and is no longer required due to the inclusion of the new provision.

The draft rule also make some minor amendments to clarify provisions regarding adjustment claims. The amendments to clauses 3.12.2(f), (g)(3) and (4) better reflect the two-way approach to calculating compensation for scheduled generators and (in respect of FCAS only) scheduled loads. In addition, the more preferable draft rule deletes the definition of "market customer's additional claim" and adds in its place the definition of "market customer's adjustment claim". This reflects the inclusion for scheduled loads of two-way compensation for FCAS revenue gains and losses. In light of this, it is no longer appropriate for a market customer only to have the ability to claim additional compensation: it also needs to be able to seek an adjustment if it wishes to have AEMO (or an independent expert for larger claims) redetermine its liability to repay revenue.

Further detail on the more preferable draft rule can be found in chapter 5.

3.1.3 Other elements of the more preferable draft rule

The more preferable draft rule will not commence immediately as AEMO will need sufficient time to revise the systems used to calculate compensation for affected participants and scheduled loads. Stakeholder feedback on implementation timing is sought.

The more preferable draft rule includes a schedule which will commence immediately following the commencement of the *Application of compensation in relation to AEMO interventions* rule on 1 October 2021. That rule reinstated the term "intervention price trading interval" as a five-minute interval, following changes made under the five-minute settlement rule.[76] Delayed commencement of the five-minute settlement rule was announced on 9 July 2020.[77]

The *five minute settlement* rule substituted "intervention price trading interval" for "intervention pricing 30-minute period" wherever it occurs in clause 3.12.2, 3.12.3, 3.15.8 and the chapter 10 definition of affected participant. The *Application of compensation in relation to AEMO interventions* rule then reinstated the term "intervention price trading interval", but as a five-minute interval. As a result of those two rules, the draft rule substitutes "intervention pricing 30-minute period" (i.e. the change made under the *five minute settlement* rule) with "intervention price trading interval" (i.e. now based on a five-minute interval due to changes made under the *Application of compensation in relation to AEMO interventions* rule). This will bring the compensation framework for affected

76 AEMC, *Five Minute Settlement, final determination*, 28 November 2017.

77 AEMC, *Delayed Implementation of five minute and global settlement, Rule determination*, 9 July 2020.

participants and scheduled loads into alignment with settlement on a five-minute basis (rather than a thirty-minute basis, as currently).

Stakeholder feedback is sought regarding what transitional arrangements should be included in the final rule. For example, it may be appropriate to include a provision to ensure that, if an AEMO intervention event which triggers intervention pricing is ongoing at the time the rule is made, the rule will not take effect until such time as that intervention event has concluded. This would avoid a situation where participants affected by an intervention event are subject to two different compensation frameworks with respect to the one intervention event.

Transitional provisions could also make clear that, where an AEMO intervention event occurs (and concludes) prior to commencement of the rule, compensation for participants affected by that event will be determined under clauses 3.12.2 and 3.12.3 as they existed prior to commencement of the rule. This would avoid any uncertainty as to the manner in which compensation should be determined when the process of determining compensation is ongoing at the time the rule commences.

3.2 Rule making test

3.2.1 Achieving the NEO

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).[78] This is the decision-making framework that the Commission must apply.

The NEO is:[79]

> 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.

3.2.2 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.

In this instance, the Commission has made a more preferable rule. The reasons are summarised below.

3.2.3 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

78 Section 88 of the NEL.

79 Section 7 of the NEL.

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 rule relates to parts of the NER that currently do not apply in the Northern Territory, the Commission has not assessed the rule against the additional elements required by the Northern Territory legislation.[80]

3.3 Assessment framework

In assessing the rule change request against the NEO the Commission has considered the following principles:

- **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?

3.4 Summary of reasons

The more preferable draft rule made by the Commission is attached to and published with this draft rule determination. The Commission's reasons for the approach adopted in the more preferable draft rule are summarised below and discussed in more detail in chapters 4 and 5.

3.4.1 Affected participant compensation for FCAS

The Commission has determined that it is appropriate to include FCAS in the affected participant compensation framework. The current framework is asymmetrical in that it only pays compensation with respect to energy revenue losses/gains and does not compensate participants when they incur FCAS revenue losses/gains. This is not appropriate, particularly

80 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.

given the growing importance of frequency services as the generation fleet undergoes rapid transition and inertia levels fall.

While the Commission has a significant work program underway to ensure that appropriate frameworks are in place to support the provision of required system services, it is also important that compensation frameworks are consistent and support the provision of required services. Compensation for FCAS, for example, is already a feature of all other compensation frameworks in the NER (for directed participants, market suspension pricing periods and administered price periods) so including FCAS in the compensation framework for affected participants (and scheduled loads - see chapter 5) creates consistency and recognises the increasing importance of the provision of ancillary services.

Risk allocation

In December 2019, the Commission made a rule change which narrowed the circumstances in which affected participant compensation is payable. As a result, such compensation is no longer payable with respect to security interventions (to obtain services other than FCAS - e.g. system strength directions) but is still payable when an intervention event triggers intervention pricing i.e. when an intervention event is to address a scarcity of energy or FCAS.

In reaching this conclusion, the Commission noted that, when AEMO intervenes due to a scarcity of energy or FCAS (thereby triggering intervention pricing), prices will generally be high, providing participants with important revenue-earning opportunities. If a participant is affected by an intervention during such periods, the Commission considered that it is reasonable to keep such participants "whole" through the payment of affected participant compensation (balanced by the requirement to repay any additional revenue earned). Such an approach was determined to be in the long term interests of consumers as it will support the ongoing viability of participants providing important services to the market.[81]

In considering AEMO's request to include FCAS in the affected participant compensation framework, the Commission remains of the view that affected participant compensation is an important means to keep participants whole if they are dispatched differently due to an intervention event that triggers intervention pricing. Consistent with this view, the Commission considers it appropriate and efficient to include FCAS in the affected participant compensation framework.

A decision not to include FCAS in the compensation framework for participants affected by intervention events could be described as a "false economy". Without the backstop of compensation, the case for investment in assets (such as large scale batteries and pumped storage) that can provide ancillary services and system support can be eroded. This in turn could increase reliance on interventions to maintain adequate FCAS levels as the provision of such services by conventional synchronous generators continues to decline. Increased reliance on interventions would likely result in higher costs to consumers in the longer term, contrary to the NEO.

81 AEMC, *Application of compensation in relation to AEMO interventions, Rule determination*, 19 December 2019, pp iv and 37.

The Commission considers that adopting a two-way approach to FCAS compensation is consistent with the objective of affected participant compensation which is to put participants in the position they would have been in but for the intervention. Simply allowing participants to claim compensation for losses, but not requiring them to repay gains, would not put participants in the position they would have been in but for the intervention. Such an approach would leave the affected participant better off at the expense of other market participants and consumers who bear the cost of FCAS compensation. As such it would be contrary to both the NEO and the assessment framework principles of consistency and appropriate risk allocation.

As noted by the National Irrigators' Council, energy consumers are not at fault when an AEMO intervention event occurs and have no opportunity to avoid the additional cost that is passed through to them after the event.[82] The Commission has determined that the approach in the draft rule, whereby the cost of compensation is net of compensation paid out to affected participants and payments received from affected participants, allocates risk more appropriately than the AEMO proposal.

Consistency and efficiency

The draft rule also promotes efficiency: as well as avoiding the administrative cost to both participants and AEMO of processing individual adjustment claims, the draft rule also supports more efficient outcomes in the market.

Adopting a consistent approach to the compensation of energy and FCAS will avoid distortionary market signals which could undermine the case for investment in technologies that provide frequency services at a time when the need for such services is growing.

Further, by adopting an approach to compensation that focuses on dispatch targets in both the dispatch run and intervention pricing run, the draft rule ensures that compensation is calculated based on consistent metrics and removes the potential for compensation to be paid to participants which have not followed dispatch targets. Implicitly rewarding such behaviour would not support the efficient functioning of the market.

Transparency and predictability

Incorporating the compensation of FCAS losses and gains into the process already used for energy ensures that the operation of the framework is transparent and predictable. Rather than ad hoc adjustment claims being made by individual participants (as per the AEMO proposal), the process will be predictable and the manner in which compensation is calculated based on clear formulae. By contrast, the manner in which adjustment claims are processed is not based on a formulaic approach. Instead this is a matter for AEMO (or, for larger claims, an independent expert) to determine on a case by case basis.

82 National Irrigators' Council, Submission to the consultation paper, p. 1.

Finally, the draft rule makes clear which participants are "affected" and the manner in which AEMO is to calculate affected participant compensation. This will avoid uncertainty about how such compensation is to be calculated and may reduce the number of adjustment claims.[83]

The Commission concludes that the more preferable draft rule will better contribute to the achievement of the NEO.

3.4.2 Compensation for scheduled loads

AEMO's rule change request sought to redefine the term "BidP" in the formula used to determine compensation for market customers with scheduled loads which are dispatched differently due to an AEMO intervention event which triggers intervention pricing. This request was prompted by concern, identified by AEMO's Intervention Pricing Working Group, that the current definition of BidP does not meet the objective of ensuring that scheduled loads are not out-of-pocket as a result of an intervention event.

The Commission agrees that the current definition of BidP is not appropriate but has determined to make a more preferable draft rule which adopts a volume weighted approach to calculating scheduled compensation, having regard to all non-zero bid bands, rather than focusing on a single band as suggested by AEMO in its rule change request.

The more preferable draft rule also includes FCAS in the scheduled compensation framework since the lack of compensation for FCAS losses/gains also has the potential to lead to under-compensation (and over-compensation) of scheduled loads which are dispatched differently as the result of an intervention event.

Including FCAS in the affected participant compensation framework while failing to address the same issue in the scheduled load compensation framework would create inappropriate inconsistency between the two frameworks. This could have distortionary effects in the market, particularly given that the two compensation frameworks apply to units which are registered as both scheduled generators and scheduled loads. The Commission considers it would be inefficient and against the principles of consistency and predictability to have such different compensation frameworks apply to a unit depending on which mode it is operating in (e.g. a battery charging as a scheduled load or discharging as a scheduled generator).

It is also appropriate to include FCAS compensation in the scheduled compensation framework given that scheduled loads (particularly large-scale batteries) are playing an increasingly important role in the ancillary services market, and ongoing investment in such technologies will be important to support power system security as the energy market transitions.

Given that scheduled generators and scheduled loads are dispatched in the same way with respect to FCAS (unlike energy), the approach to FCAS compensation for scheduled loads mirrors that proposed for affected participants (scheduled generators) which in turn mirrors the approach to affected participant compensation for energy revenue losses/gains. This

83 For example, an affected participant claimed that it was not liable to repay revenue to AEMO. The independent expert engaged to determine the adjustment claim considered that the data used for intervention pricing was but one possible means of calculating affected participant compensation. See Synergies Economic Consulting, *Independent Expert Determination on Claim for Additional Compensation from Directions of 29 August 2018, Final report,* January 2019, p. 4.

means that FCAS compensation for scheduled loads will be a two-way process (in contrast to the one-way process proposed for scheduled load energy compensation).

The Commission has determined that the draft rule, including both the revised formula for determining energy compensation and the inclusion of FCAS compensation, accords with the NEO and meets the assessment framework principles for the following reasons.

Consistency

The draft rule promotes consistency by incorporating the same compensation objective for scheduled generators and scheduled loads (that is, the objective of compensation is to put the participant in the position it would have been in had the intervention event not occurred). To the extent appropriate, the draft rule also adopts a consistent compensation approach as between affected participants and scheduled loads:

- Both frameworks encompass energy and FCAS.
- The frameworks adopt an appropriate level of consistency in the calculation of compensation: that is, a one-way approach to energy compensation for scheduled loads (reflecting the different approach to dispatching such loads); and a two-way approach to FCAS compensation (reflecting that the approach to dispatching generators and loads is the same with respect to FCAS).

Efficiency

By focusing on consistent metrics (i.e. the dispatch targets in the two NEMDE runs used to implement intervention pricing), the new approach to calculating both energy and FCAS compensation removes the potential for participants to be compensated under clause 3.12.2 simply because they did not follow dispatch targets. This removes an unintended incentive that would reward inefficient participant behaviour.

The more preferable draft rule also promotes efficiency by removing the potential for two kinds of compensation (directed participant compensation and compensation under clause 3.12.2) to be paid with respect to the one unit for the same intervention price trading interval. Allowing such "double dipping" would impose inefficient costs on consumers.

Transparency and predictability

Adopting a volume-weighted approach to scheduled load energy compensation enhances transparency and predictability. The revised formula means that the value of compensation is predictable and will not change as a result of the structure of a scheduled load's dispatch bid. The new formula also formalises the existing practice of AEMO whereby compensation is not paid when the value of QD is negative. In doing so, the more preferable draft rule increases transparency with respect to how compensation is to be calculated.

By incorporating FCAS compensation for scheduled loads into AEMO's automatic calculation of compensation, rather than requiring scheduled loads to lodge claims for FCAS losses, the more preferable draft rule adopts an approach that is both transparent and predictable: compensation will be calculated in the first instance based on a formula using data that is available to market participants, rather than being determined by AEMO or an independent expert.

The revised formula makes clear that the process of calculating compensation is to be based on the dispatch targets in the two runs of NEMDE (the dispatch run and the intervention pricing run) used to implement intervention pricing. In this way, the more preferable draft rule increases transparency and predictability, and removes the potential for compensation to be paid to participants which have not followed their dispatch targets.

Risk allocation

The Commission acknowledges that the more preferable draft rule may increase the quantum of compensation paid to scheduled loads with respect to energy losses. However, the Commission considers that the revised formula more appropriately allocates risk than does the current formula. In this regard, the Commission notes that the amount of compensation paid to scheduled loads will serve to reduce the amount they would otherwise be required to pay for energy as part of the settlement process. In other words, the energy "compensation" for scheduled loads is a financial transfer designed to re-balance the ledger to make good the fact that the scheduled load would otherwise overpay for the energy it consumed during the intervention event due to the application of intervention pricing.

As a result, the revised formula reduces the risk that scheduled loads will, under the current framework, pay more than they should for energy consumed during an intervention event that triggers intervention pricing. The Commission considers that this reallocation of risk is both important and appropriate given the need for significant investment in scheduled load technology to provide dispatchable capacity and system services as the generation fleet transitions.

The revised formula also provides that no compensation is payable where "QD" is negative. This avoids the risk of over-compensation in circumstances where a scheduled load trips or where intervention pricing produces anomalous results. This avoids unwarranted costs being passed through to consumers and other market participants. Accordingly, the Commission has determined that the new approach to calculating scheduled load compensation strikes a fair balance between the interests of scheduled loads and those who bear the cost of compensation.[84]

84 Where the reason for the intervention event is to address a shortage of energy, compensation costs will be recovered from market customers and hence consumers in the region which benefited from the intervention. Where the reason for the intervention is to address a shortage of FCAS, compensation costs will be recovered in line with the normal process for recovering the cost of the FCAS service in question: i.e. from generators, small generation aggregators and market customers.

4 AFFECTED PARTICIPANT COMPENSATION FOR FCAS LOSSES

This chapter examines AEMO's request to allow affected participants to claim compensation with respect to FCAS losses in addition to energy. It sets out the issues raised by the rule change request, stakeholder views and the Commission's analysis.

There are three main elements of the Commission's draft determination covered in this chapter:

- It is appropriate to include FCAS in the affected participant compensation framework.
- This should be done using the same automatic, two-way calculation of compensation that applies to energy revenue losses and gains.
- The calculation of affected participant compensation should not be automatically adjusted to take account of changes to FCAS liabilities (resulting from changes to dispatch targets due to an intervention event).

4.1 Issues raised by the rule change request

This section discusses:

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

4.1.1 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.[85] 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".[86]

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.[87] The directions review report noted that there was a need to establish a consistent framework for directions in those other ancillary services sectors.

85 These were the predecessors of AEMO and the AEMC.

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

87 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.

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.[88]

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.[89] This unsuccessful claim is referenced by AEMO in its rule change request and discussed in more detail in Appendix C.

Synergies concluded its report with the following comment:[90]

> 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 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.

88 Though prior to 2008 it was numbered differently as clause 3.12.11.

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

90 ibid, p. 37.

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[91] 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

91 This is relevant to the other AEMO rule change request discussed in this determination, *Compensation for scheduled loads affected by interventions*, discussed further in chapter 5.

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.

Circumstances when affected participant compensation is payable

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 directions) that trigger intervention pricing under clause 3.9.3(b) of the NER.[92] Such interventions are still relatively infrequent (and far less frequent than security related interventions).

In the period since 2010, the RERT has been activated 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 directions addressing a shortage of energy have been issued: in February and March 2017, in February 2020 in NSW, and two directions in February 2020 in South Australia during the islanding event. Five directions to maintain FCAS levels were also issued during the SA islanding event in February 2020.[93] By contrast, well over 400 system strength directions have been issued in South Australia in the period since April 2017.

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

4.1.2 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 issues:

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 increase administrative costs to both participants and AEMO relative to the approach adopted in relation to energy.[94]
2. This approach means that the affected participant will only lodge an adjustment claim in relation to FCAS if it is out of pocket.[95] However this is inconsistent with the objective of affected participant compensation which is to put the participant in the position it would have been in but for the intervention. Adopting the approach proposed by AEMO would

92 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.

93 IES Advisory Services, *AEMO Directions to Participants in South Australia on 2 and 4 February 2020, Final Determination*, 19 August 2000, p. 1.

94 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.

95 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".

also create inconsistency as between energy and FCAS and inconsistency with the cost recovery provisions discussed above.

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.[96] For example, if a generator is constrained down by NEMDE due to an intervention event that triggers intervention pricing,[97] they will be paid compensation by AEMO to put them in the position that they would have been in had the intervention event not occurred. That is, they will be paid the difference between the amount they would have received based on their dispatch targets in the intervention pricing run (combined with the price from the intervention pricing run), and the trading amount they have received based on their metered output multiplied by the intervention price.

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 with respect to FCAS does not involve this initial calculation of 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.[98] Allowing participants to claim for FCAS losses but not requiring them to repay FCAS gains would result in higher compensation costs being passed on to other market participants and consumers.

4.1.3 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 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

96 See clause 3.12.2(c) of the NER.

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

98 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).

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.[99]

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 B.2). During the recent South Australian 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.[100] [101]

The consultation paper explored 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. The consultation paper noted that 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.

This administrative cost and complexity was a factor in the Commission's final determination and rule to establish a demand response mechanism.[102] 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 have informed consideration of this issue in relation to participants affected by intervention events.

4.2 Stakeholder views

The consultation paper sought stakeholder views as to 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

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

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

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

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

dealt with only in paragraph (j)) or whether consideration should be given to also including FCAS in paragraph (c)(1).[103] It also sought views on whether compensation for changes in FCAS revenues should be net of changes in FCAS liabilities.

In response to the consultation paper, the Commission received submissions from ten stakeholders:

- five from consumer groups: Energy Users Association of Australia (EUAA), Public Interest Advocacy Centre (PIAC), South Australian Chamber of Mines and Energy (SACOME), National Irrigators' Council (NIC) and Central Irrigation Trust (CIT), and
- five from market participants: CS Energy, ERM Power, EnergyAustralia (EA), AGL and Tesla.

There was considerable consistency across the submissions provided by these two groups. Consumer groups expressed concern about the costs to consumers of widening the affected participant compensation framework to include FCAS (particularly in light of the high FCAS costs passed through to consumers following the SA islanding event in January-February 2020). EUAA and PIAC supported a two-way approach to compensation, noting that this would lower the net cost of compensation.

Market participants were supportive of including FCAS in the affected participant compensation framework. Most supported the approach of calculating FCAS compensation automatically, consistent with the approach to energy (i.e. a two-way approach to compensating losses and repaying gains), while Tesla supported the AEMO proposal (compensating FCAS loss only).

Market participants were also supportive of the proposal to take FCAS liabilities into account when calculating FCAS compensation for affected participants. Most supported this being done on an automatic basis but recognised that this may not be cost effective. In that case, they supported allowing affected participants to make an adjustment claim with respect to FCAS liabilities.

4.2.1 Consumer views

The EUAA noted that AEMO's proposal to allow affected participants to lodge a claim for FCAS losses "appears to create an asymmetry between compensation for energy and FCAS, and is likely to increase compensation costs to consumers and other participants". It considered that it "would be preferable that FCAS is treated in the same way as energy – including it in the automatic calculation of compensation and adopting a two way approach to compensation rather than the proposed one way (additional claim) approach. This would align the rule change with the compensation principle of leaving the affected participant in the position it would have been in but for the intervention."[104]

103 Clause 3.12.2(c)(1) 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 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).

104 EUAA, Submission to the consultation paper, p. 1.

The South Australian Chamber of Mines and Energy (SACOME) noted the importance of energy prices as a component of resource sector operators' business viability. SACOME stated that it "does not support rule changes that will increase energy prices for SACOME member companies for minimal benefit, particularly when the current compensatory framework has not detrimentally impacted on the services provided by participants in the National Electricity Market".[105]

SACOME notes that its member companies have experienced substantial FCAS price increases in South Australia and that, in Q1 2020, total NEM system costs increased to $310 million, representing 8 per cent of the energy costs for the quarter, when the typical NEM system costs quarterly value is 1-2 per cent.[106] It called for greater transparency around the use of interventions and increased accountability for lowering the cost of interventions over time.[107]

The National Irrigators' Council (NIC) expressed concern that the proposed rule changes would protect market participants' revenue "at the expense of energy consumers, who are not at fault and have no opportunity to avoid the additional cost"[108]

The NIC does not believe that consumers "should be treated as a bottomless insurer for faults, be they network faults, system inadequacies or policy failures. NIC strongly disagreed with the contention that the cost to consumers of this recommendation is not significant and that the assessment framework need not focus on price as one of its key criteria. Price to consumers, and the equity of who bears it, should be a key consideration."[109]

Similarly, the Central Irrigation Trust (CIT) stated: "As an energy consumer in South Australia in 2020 we have felt the significant financial impact of skyrocketing AEMO charges resulting from both directions and FCAS. These charges are imposed after the fact and with no consultation or communication with the customer. CIT does not support the rule changes suggested as again it appears the changes will see higher costs for the consumers and higher revenues for the generators. With the limited number of generators available in South Australia to provide these services that are already handsomely rewarded."[110]

PIAC expressed support for improving the consistency, transparency, predictability and efficiency of compensation mechanisms for participants and scheduled loads affected by intervention events. However, it was concerned about cost implications for consumers of introducing a new type of compensation, and considered that more analysis of cost impacts is required. PIAC supported adopting an automatic approach to the calculation of FCAS compensation, rather than requiring participants to lodge a claim to recoup FCAS losses. It also supported a two-way compensation process to limit the net compensation paid out to affected participants and to ensure compensation is sending efficient and transparent signals

105 SACOME, Submission to the consultation paper, p. 2.

106 ibid.

107 ibid, p. 3.

108 NIC, Submission to the consultation paper, p. 1.

109 It is noted that the assessment framework principles set out in the consultation paper are in addition to the NEO, which focuses on the long term interests of consumers with respect to the price of electricity, among other things.

110 CIT, Submission to the consultation paper, p. 1.

to market participants and scheduled loads. PIAC supported FCAS compensation being net of any adjustment required in relation to FCAS liabilities.[111]

4.2.2 Market participant views

CS Energy supported including FCAS in the automatic calculation of affected participant compensation, consistent with the two-way approach adopted to energy (rather than by allowing participants to claim for FCAS losses, as proposed by AEMO). It considers this will support more streamlined processes and equitable outcomes. CS Energy also supported compensation taking into account changes to FCAS liabilities resulting from an intervention event. It stated its preference is for "the impact of FCAS liabilities to form part of an automatic calculation for compensation. However, if the AEMC's cost benefit analysis does not warrant AEMO developing an automatic process, CS Energy would then support the option for Participants to submit an adjustment claim. This is a less preferable option, as CS Energy believes it will be challenging for Participants to determine their FCAS liabilities arising from an intervention event."[112]

Similarly, ERM Power supported "the AEMC's proposed alternative model where FCAS would form part of an automatically calculated compensation process determined in accordance with clause 3.12.2(c)(1), in addition to including FCAS in paragraph 3.12.2 (j). ERM Power considers that this will reduce the administrative costs to the Market and result in the 'fair' outcome for all market participants". ERM Power also supported adjusting compensation to take into account FCAS liabilities, stating "provided this can easily be calculated under the automatic compensation calculated process by AEMO then ERM Power agrees that participant compensation should be net of FCAS liabilities. FCAS liabilities can be high and are a direct cost that can be incurred due to market intervention. If this is not part of the automatic compensation process, then FCAS costs should remain available for an adjustment claim by an affected participant under clause 3.12.2(f)."[113]

EnergyAustralia considered that FCAS compensation should be calculated automatically, noting that this would align FCAS treatment with energy compensation protocols and accord with the AEMC's consistency assessment principle. It also supported taking into account changes to FCAS liabilities which it described as forming part of the total short run cost of operation. It expressed a preference that this adjustment be made automatically or, if that is not cost effective, by allowing participants to lodge an adjustment claim.[114]

AGL supported the AEMC's alternative proposal of calculating affected participant compensation for FCAS automatically (rather than requiring participants to lodge a claim for FCAS losses only, per the AEMO proposal). It noted that this would result in administrative efficiency and consistency with the approach to energy compensation. AGL also supported the proposal that compensation be net of changes to FCAS liabilities, commenting that "this

111 PIAC, Submission to the consultation paper, pp 1-2.
112 CS Energy, Submission to the consultation paper, p. 2.
113 ERM Power, Submission to the consultation paper, pp 1-2.
114 EnergyAustralia, Submission to the consultation paper, p. 2.

approach is consistent with treatment of energy and prevents over or under recovery by affected participants".[115]

AGL queried "whether compensation should be payable if the dispatch targets are identical in NEMDE's intervention and dispatch runs. If the targets are identical in the two NEMDE runs then any compensation paid though the application of metering data may be rewarding the participant for not following targets".[116] While this comment was included in the section of the submission discussing compensation for scheduled loads, the issue is relevant to both affected participants and scheduled loads.

Tesla strongly supported "the need to address potential asymmetries in current framework design – including between generators and loads; and across energy and Frequency Control Ancillary Service (FCAS) compensation. The compensation framework should be revised to ensure principles of technology and market participant neutrality." Tesla supported compensation for both scheduled generators (affected participants) and scheduled loads with respect to FCAS losses (i.e. in line with the AEMO proposal to allow affected participants to claim FCAS losses, rather than the suggested alternative of calculating FCAS compensation automatically, consistent with the two-way approach to energy compensation).[117]

4.3 Analysis

This sections sets out the Commission's analysis of the implications of including FCAS in the affected participant compensation framework.

4.3.1 Affected participant compensation is only payable when an intervention event triggers intervention pricing

Since December 2019, affected participant compensation is only payable in connection with intervention events to address a shortage of energy or FCAS (i.e. interventions which trigger intervention pricing). This is critically important in considering the impact of the rule change request submitted by AEMO because these intervention events are infrequent compared with interventions to maintain system security (e.g. system strength directions which no longer trigger intervention pricing, meaning affected participant compensation is no longer payable in connection with them). This means that the cost implications of including FCAS in the affected participant compensation framework are considerably more limited than they would have been had such compensation still been payable in connection with security interventions.

Further, interventions to address a shortage of energy or FCAS_are generally of short duration (e.g. four to six hours) while security interventions can last for several days and in some cases weeks. Accordingly, the quantum of compensation payable in connection with interventions which trigger intervention pricing is relatively limited.

115 AGL, Submission to the consultation paper, pp 1-2.

116 ibid p. 4.

117 Tesla, Submission to the consultation paper, p. 2.

4.3.2 Complexities associated with estimating impact of proposed change

Estimating the impact of the rule change on compensation costs is complex as there are many, often counterveiling, factors that need to be taken into account. The compensation cost ultimately passed through to market participants and consumers will be a function of netting off at several levels, including those discussed below.

FCAS compensation will be a function of the intervention event's positive and negative impacts on enablement targets for the eight FCAS markets (four markets for services that raise frequency and four market for services that lower frequency). Changes in enablement targets and thus revenue for one FCAS market (e.g. a raise service) may be offset by changes in targets and thus revenue for another service (e.g. a lower service).[118] As a result, *net* changes in FCAS revenue may tend to be small since, for example, increases in enablement of raise services may be offset to some degree by reductions in enablement of lower services and vice versa.

It is this net change in FCAS revenue losses and gains which will determine the quantum of FCAS compensation payable to or by affected participants. This is a key difference between the approach adopted in the draft rule and the approach proposed by AEMO in its rule change request (allowing participants to claim for FCAS losses but not requiring them to repay gains).

Adopting a two-way approach to FCAS compensation, rather than a one-way approach as proposed by AEMO, will result in lower compensation costs being passed through to market participants and consumers. This is because the "compensation recovery amount" will be lower (all else equal) if affected participants are required to repay FCAS gains (in addition to receiving compensation to offset their FCAS losses). The compensation recovery amount is the amount of money that needs to be recouped from other participants and consumers in order to cover the cost to AEMO of compensating directed and affected participants in the wake of an intervention event.[119]

Under the draft rule, compensation payments to affected participants will be the sum of energy compensation and FCAS compensation.[120] Depending on the value of each, this process may lead to a lower net compensation figure than under current arrangements. For example, an affected participant may be entitled to receive compensation for lost energy revenue but required to repay FCAS revenue gains (and vice versa).

In such circumstances, the net amount of compensation paid would be less than would otherwise be the case. It could also result in the value of compensation falling below the $5,000 threshold, meaning that no compensation is payable.[121] Examples of such effects

118 See Appendix B.3 for an explanation of how FCAS bids take the form of the generic "FCAS trapezium".

119 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.

120 See clause 3.12.2(c)(1)(iii) of the draft rule.

121 The $5,000 threshold limits the payment of affected participant compensation to situations where the amount to be paid to, or by, an affected participant exceeds this amount: see clause 3.12.2(b) of the NER.

were observed in the Commission's analysis of changes in energy dispatch and FCAS enablement targets resulting from intervention events.

As per the current framework, affected participant compensation is netted out across all units owned by a given participant: some units may be better off, some may be worse off due to an intervention and the compensation paid to, or by, the affected participant takes account of gains and losses across the participant's portfolio.

The Commission notes that AEMO has identified an issue (concerning generators and loads becoming trapped in their FCAS trapeziums) that may impact the accuracy of the intervention pricing run enablement targets which would be used to calculate FCAS compensation.[122] If this problem were to occur and negatively impact the position of an affected participant (or scheduled load), it could seek to lodge an adjustment claim under clause 3.12.2(f). This issue is discussed further in Appendix B.4. After consultation with the Intervention Pricing Working Group, AEMO has developed a solution, however this is yet to be implemented. AEMO has determined that the proposed change to NEMDE should be made "as resources allow". [123]

4.3.3 How might the inclusion of FCAS impact affected participant compensation costs?

The Commission is mindful of stakeholder concern regarding the cost to consumers of widening the affected participant compensation framework to include FCAS in addition to energy. In this regard it is relevant to note that, while the cost of energy (and hence the cost of compensation for energy directions) is recovered entirely from market customers and ultimately consumers,[124] the cost of FCAS services (and hence the cost of compensation for FCAS directions) is shared among a variety of participants depending on the nature of the service in question.[125]

Contingency FCAS costs (and hence the cost of compensation for contingency FCAS directions) are recovered in proportion to the energy consumed or generated by relevant market participants: raise services are recovered from market generators or market small generation aggregators. Lower services are recovered from market customers.[126]

Regulation FCAS costs (and hence the cost of compensation for regulation FCAS directions) are recovered from participants in accordance with a causer-pays or contribution factor procedure. Under this approach, regulation FCAS costs are recovered from market participants deemed to have "caused" the need for the service, where this is possible to determine from metering. The residual amount of regulation FCAS costs that cannot be

122 AEMO, *Intervention pricing methodology, Final report and determination*, September 2018.

123 AEMO, *Intervention pricing methodology, Final report and determination, September 2018,* p. 8.

124 Clause 3.15.8(a) of the NER.

125 Clause 3.15.8(e) of the NER.

126 AEMO, *Settlements guide to ancillary services payment and recovery*, February 2020, p. 7.

allocated to metered "causers" is smeared across all market customers based on energy consumption.[127] [128]

In January-February 2020, South Australia (together with Portland aluminium smelter and Mortlake power station) was separated from the remainder of the NEM following storm damage to the SA-VIC interconnector. As a result, FCAS services needed to be sourced from within the SA region. FCAS prices rose in response to the islanding event and were a major factor in FCAS prices reaching record levels of $227m in Q1 2020. Of these costs, $166 million was recovered from generators, with the remainder ($61 million) recovered from retailers.[129] The largest contributor to increased FCAS costs was the fast raise contingency service which is paid for by generators. Concern about the high FCAS costs passed through to consumers is expressed in several of the submissions made in response to the consultation paper.

4.3.4 Affected participant FCAS compensation would be small fraction of total FCAS costs

It is not possible to estimate with any precision how the inclusion of FCAS will impact affected participant compensation costs as that will depend on the frequency and nature of interventions and the circumstances applicable at the time. Nonetheless, the Commission has examined recent AEMO intervention events (both RERT activations and directions issued during the SA islanding event) to develop some indicative numbers to help inform our considerations of how the inclusion of FCAS might in future change the quantum of affected participant compensation paid in connection with such events.

The analysis shows that FCAS compensation amounts would be highly variable:

- Across the three RERT activations in January 2020, most amounts of FCAS compensation would likely have been small (e.g. average FCAS revenue change per unit across the three January 2020 RERT events was $1,986, well below the $5,000 compensation threshold).
- However, some FCAS compensation costs would have been more significant (range was -$171,000 to +$187,000). These larger amounts were estimated based on changes in FCAS enablement targets on 31 January 2020 - a day that featured a very tight supply demand balance, prices at the market price cap, and the separation of South Australia from the rest of the NEM.

The high FCAS costs that were passed through to market participants and consumers in South Australia were primarily due to the 18 day islanding event, which meant that FCAS had to be sourced from within the SA region - rather than from across the NEM, as would occur under normal operating conditions. While directions were issued during the islanding event

127 ibid.

128 AEMO has recommended that the NER be amended to allow the residual factor of regulated FCAS cost recovery to be apportioned to both market customers and non-metered market generation (where currently market customers bear this cost alone). This would more efficiently allocate the costs of regulation FCAS. This issue is being examined as part of the Commission's consideration of the *Primary frequency response incentive arrangements* rule change request: see AEMC, *System services rule changes, Consultation paper,* 2 July 2020, p. 68 and p. 101.

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

(for the provision of energy, fault current and FCAS), the costs associated with these directions were small by comparison with total FCAS costs.[130]

It was estimated that including FCAS in the affected participant compensation framework in the first quarter of 2020 would add costs accounting for less than one per cent of the total FCAS costs incurred by the market in Q1 2020. As previously noted, total FCAS costs in Q1 2020 were $227m. By contrast, AEMC analysis suggests that affected participant compensation payable for FCAS over the same period would have comprised less than approximately $400,000 in compensation for RERT activations.

The estimate of $400,000 is not precise due to the netting out effects noted above. For example, in some instances, we observed that the inclusion of FCAS in the affected participant compensation framework would have resulted in lower total compensation being paid to an affected participant (since negative FCAS compensation would reduce positive energy compensation).

The approximate figure of $400,000 contrasts with the more than $4.8m paid in energy related affected participant compensation following the January 2020 RERT activations, the majority of which ($4.74m) was paid in connection with the RERT activation in NSW and Victoria on 31 January 2020.[131] This compensation quantum is considerably higher than previous affected participant compensation payments following RERT activations and reflects that the spot price was at the market price cap for several hours that day.

By contrast with the events of 31 January 2020, no affected participant compensation was paid in relation to the RERT activation in Victoria on 30 November 2017, and $170,000 in compensation was paid in connection with the RERT activation in Victoria and South Australia on 19 January 2018.[132] Affected participant compensation paid in connection with the RERT activation on 24 January 2019 was $3.3m, and on 25 January 2019 was $237,000.[133]

Given the relative cost of energy and FCAS, it is reasonable to expect that FCAS compensation costs associated with such events would be less than the quantum of energy compensation paid to affected participants in connection with these events.

The Commission notes that directions issued in South Australia in early February 2020 also resulted in changes to several participants' FCAS enablement targets. While most changes in targets were small, there were instances where the inclusion of FCAS would have had a material impact on the quantum of compensation paid to or by affected participants. However, having regard for the amount of compensation that would be paid to affected

130 See for example the compensation paid to batteries in South Australia following five directions to maintain a state of charge and bid regulation FCAS to zero in order to provide maximum available contingency FCAS. Compensation of less than $25,000 was awarded for the provision of these services. See IES, *AEMO Directions to Participants in South Australia on 2 and 4 February 2020, Final determination*, 19 August 2020. The Commission notes that this report also determined additional compensation was payable to directed participants, however the compensation paid was due to the fact that FCAS prices at the time were higher than the 90th percentile price and hence, under the compensation formula for directed participants, amounts owed by the directed participants to AEMO needed to be reversed to ensure the participants were not out-of-pocket. As such, these claims simply reflect the high ancillary service prices at the time and effectively did not result in the payment of additional compensation. Including these compensation costs, alongside total FCAS costs, would amount to double counting.

131 This difference in energy and FCAS compensation reflects that FCAS prices are typically much lower than energy prices.

132 AEMO, *Activation of unscheduled reserves for Victoria – 30 November 2017*, May 2018, p. 9, and AEMO, *Activation of unscheduled reserves for Victoria and South Australia – 19 January 2018*, May 2018, p. 9.

133 AEMO, *RERT Report for 2018-19*.

participants, and the amount of compensation that would be paid by participants to AEMO, the net cost of FCAS compensation associated with the directions issued on 1 and 2 February 2020 would have been in the order of more than $220,000 being repaid to AEMO. As such, the inclusion of FCAS in affected participant compensation would not - in connection with these intervention events - have increased costs to other market participants and consumers.

The Commission notes that FCAS compensation costs would be shared among market generators, small generation aggregators and market customers, consistent with the approach to recovering the cost of the various FCAS services. Given that the fast raise contingency service was the most costly service during the SA islanding event, the compensation cost associated with this service may comprise a higher proportion of the total than the cost of other FCAS services. Compensation costs for this service would be recovered from generators, rather than consumers, thereby mitigating the direct impact on consumers of including FCAS in the affected participant compensation framework.

4.3.5 Implications of proposed change for 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 interventions to address a shortage of energy or FCAS 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 such interventions, even though the access arrangements in the NEM mean that, while generators have a right to connect, they do not have a right to be dispatched.[134]

This is a relevant factor in considering whether to implement AEMO's proposal to compensate participants for changes in FCAS revenue resulting from intervention events that trigger intervention pricing. The Commission notes that, as the generation mix in the NEM changes, inertia levels are falling and the management of frequency is increasingly challenging. In light of this, it is important that market participants which provide frequency services are not disadvantaged by compensation frameworks that were designed at a time when the NEM looked very different (with a generation fleet characterised by high levels of inertia and hence comparatively stable frequency).

4.3.6 Taking into account changes in FCAS liabilities

The consultation paper considered whether affected participant compensation should be calculated net of FCAS costs (liabilities) incurred or avoided as a result of changes to dispatch targets, consistent with the approach adopted in relation to energy costs incurred or avoided

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

(fuel, maintenance, staff). Several stakeholders expressed support for this approach and noted that, if it is not cost effective for AEMO to calculate such changes in liability automatically (in the course of calculating compensation for energy and FCAS revenue gains/losses), affected participants should have the option to lodge an adjustment claim in order to recoup losses arising from increased FCAS liabilities.

The Commission has considered this issue further and concluded that it is not efficient to incorporate FCAS liability adjustments as part of the automatic calculation of affected participant compensation. The data used for the purpose of taking into account direct costs incurred or avoided by affected generators is static (being drawn from the data set that underpins the Integrated System Plan). By contrast, the data used to calculate FCAS liabilities is dynamic: it changes to reflect not only the varying costs of FCAS services over time, but also the changing causer pays contribution factors which determine how the cost of regulation FCAS services is apportioned to market participants.

While the data used to calculate affected participant compensation is drawn from the market management system (MMS), the data needed to calculate FCAS liabilities sits outside the MMS. Combining the two systems to recalculate liabilities automatically would be complex and, during normal operating conditions, would likely have limited impact on the compensation payable to affected participants.

Accordingly, the draft rule does not include a provision requiring AEMO to take into account changes in FCAS liabilities when determining the quantum of energy and FCAS compensation payable to affected participants. However, existing paragraphs (f) and (j) in clause 3.12.2 allow affected participants to lodge an adjustment claim if they consider that their compensation (or liability to repay revenue) should be redetermined. The more preferable draft rule amends this provision by adding a reference to market customers, in addition to affected participants, so that the compensation framework is appropriately consistent.

While paragraph (j) refers to direct costs such as fuel costs, incremental maintenance and manning costs, this list of factors is inclusive rather than exhaustive. As such, an affected participant or market customer can seek an adjustment having regard for the items set out in paragraph (j), namely: direct costs incurred or avoided as a result of the AEMO intervention event, any amounts which the participant is entitled to receive under clauses 3.15.6 and 3.15.6A, the regional reference price, and ancillary service prices.

In a similar way to clause 3.12.2(f) and (j), clause 3.15.7B enables directed participants to lodge a claim for additional net direct costs and loss of revenue where such participants are still out-of-pocket following the automatic calculation of compensation under clause 3.15.7. Clause 3.15.7B(a3) lists (without limitation) the kinds of net direct costs that may be the subject of a claim for additional compensation. These include fuel costs, incremental maintenance and staffing costs, maintenance acceleration or delay costs, and other costs incurred to enable the unit to comply with the direction. As such, clause 3.15.7B(a3) is similar to the list in clause 3.12.2(j) of direct costs incurred or avoided by an affected participant as a result of an intervention event - a list which is inclusive rather than exhaustive.

Following a South Australia separation event on 2 March 2020, a generator lodged a claim for additional directed participant compensation which included a claim to recoup the additional

FCAS charges that the generator incurred as a result of compliance with the direction. The claimant noted that it would not have incurred these charges had they not been directed. The independent expert engaged to determine the claim agreed, in a draft determination, that the costs were incurred as a result of the direction and should be compensated.[135] Having regard for this example, it would be open to an affected participant to lodge an adjustment claim in the event that changes to its dispatch targets resulted in a material change in its FCAS liabilities (noting that an adjustment claim can only be lodged if it exceeds the $5,000 compensation threshold set out in clause 3.12.2(i)).

Given that intervention events which trigger intervention pricing are generally of short duration (e.g. four to six hours), the Commission does not anticipate that affected participants (as distinct from directed participants) would often experience changes in FCAS liabilities which exceed the $5,000 threshold. As such, the ability to lodge a claim to recoup increased FCAS liabilities (without a corresponding obligation to repay reductions in FCAS liabilities) is not expected to result in significant additional compensation costs being passed through to other market participants and consumers.

4.3.7 Comparing counterfactual targets with metered generation data

As noted in section 4.2.2, AGL queried "whether compensation should be payable if the dispatch targets are identical in NEMDE's intervention and dispatch runs. If the targets are identical in the two NEMDE runs then any compensation paid though the application of metering data may be rewarding the participant for not following targets".[136] While this comment was included in the section of the submission discussing compensation for scheduled loads, the issue is relevant to both affected participants and scheduled loads.

The Commission has determined that it is appropriate to address this issue in the calculation of compensation for both affected participants and scheduled loads which are dispatched differently due to an intervention event. As such, the draft rule removes the current reference to metering data in the formula for calculating scheduled load compensation, and amends clause 3.12.2(c)(1)(ii)(B) (renumbered as 3.12.2(c)(1)(iii)(B) in the draft rule) so that it no longer refers to the trading amount set out in the affected participant's final statement (which amount is in turn based on metering data). Instead, the draft rule calculates the amount of compensation owed to, or by, affected participants and scheduled loads based on the difference in the dispatch targets in the two runs of the NEM dispatch engine (NEMDE) used to implement intervention pricing.[137]

This approach enables AEMO to calculate compensation on a consistent basis - comparing targets from the two runs of NEMDE rather than comparing two qualitatively different data sets (i.e. comparing the intervention pricing run dispatch targets with metered data). As noted by AGL in its submission, it will also avoid a situation whereby compensation is only payable to a participant as a result of it not following its dispatch targets. Finally, adopting

135 IES, *Direction to participants in South Australia in March 2020, Draft determination report*, 14 July 2020, p. 5.

136 AGL, Submission to the consultation paper, pp 1-2.

137 When AEMO implements intervention pricing under clause 3.9.3(b), it does so in accordance with the methodology developed by AEMO under clause 3.9.3(e). In accordance with that methodology, AEMO runs NEMDE twice: once to dispatch market participants (the dispatch run or outturn run), and once to set the price at which the market clears (the intervention pricing run).

this approach will avoid uncertainty about when a participant is "affected" and the manner in which compensation for affected participants should be calculated.

Such issues were raised by the independent expert engaged to determine an adjustment claim by CS Energy.[138] This followed a system strength direction issued in August 2018 which resulted in changes to CS Energy's Gladstone power station dispatch targets and a requirement to repay more than $280,000 in additional energy revenue to AEMO.[139] CS Energy disputed its liability to repay this revenue, arguing that the pricing outcomes that resulted in the changed dispatch targets were caused by a known problem with the intervention pricing methodology (an issue which has since been corrected).

Synergies was the independent expert engaged to determine the claim. It decided in favour of CS Energy and set its liability to zero. In the course of its final determination, Synergies made the following comments regarding the lack of clarity in the rules as to how an affected participant is identified and how compensation is to be calculated.[140]

> Considering first what the Rules permit, Synergies believes that there is scope under the Rules for the independent expert to apply an approach to estimating dispatch in the absence of the direction that departs from the Intervention Pricing Methodology as the basis for a) determining whether CS Energy is an Affected Participant and b) for quantifying the effect of the direction. In support of this view, we note that:
>
> - there is no explicit step prescribed in Chapter 3 or Chapter 10 that specifies how AEMO is to identify Affected Participants, rather it is implied that this status will be apparent to AEMO.
> - the requirements as to determining compensation that AEMO must follow are addressed in subclauses 3.12.2(a)(1) and 3.12.2(j). These explain the general principle of restitution and the matters to consider in evaluating costs and revenues but do not specify how the change in dispatch level is to be calculated
> - there is a requirement in 3.12.2(c) for AEMO to advise an Affected Participant of the estimated level of dispatch that its generating unit would have been dispatched at had the intervention event not occurred. Again there is no prescription of how this level is to be calculated.

The draft rule addresses these issues by providing clarity as to how compensation is calculated and making clear which participants are and are not "affected". In particular, no affected participant compensation will be payable when the dispatch targets for a given participant are the same in both the dispatch run (used to dispatch the market) and the intervention pricing run (used to set the price at which the market clears).

Increased clarity in this regard will enhance transparency and predictability which in turn will avoid unnecessary administrative costs for both participants and AEMO.

138 Synergies Economic Consulting, *Independent expert determination on claim for additional compensation from directions of 29 August 2018, Final report*, January 2019.

139 The Commission notes that affected participant compensation is no longer payable in connection with system strength directions, following rule changes made in December 2019.

140 ibid, p. 17.

4.4 Conclusions

Having regard to the issues explored in the consultation paper, feedback from stakeholders, further analysis, the NEO and assessment framework, the Commission has determined that it is appropriate to include FCAS in the affected participant compensation framework but not in the manner proposed by AEMO. The more preferable draft rule instead incorporates FCAS into the automatic, two-way calculation of compensation that applies to energy revenue losses and gains.

The Commission considers that adopting a two-way approach to FCAS compensation is consistent with appropriate risk allocation and the objective of affected participant compensation which is to put participants in the position they would have been in but for the intervention. Simply allowing participants to claim compensation for losses, but not requiring them to repay gains, would not put participants in the position they would have been in but for the intervention. Such an approach would leave the affected participant better off at the expense of other market participants and consumers who bear the cost of FCAS compensation. As such it would be contrary to both the NEO and the assessment framework principles of consistency and appropriate risk allocation.

The Commission considers that the more preferable draft rule better allocates risk than does the AEMO proposal. As noted by the National Irrigators' Council, energy consumers are not at fault when an AEMO intervention event occurs and have no opportunity to avoid the additional cost that is passed through to them after the event. Thus the approach in the draft rule, whereby the cost of compensation is net of compensation paid out to affected participants and payments received from affected participants, allocates risk more appropriately than the AEMO proposal, which would allow claims for loss but not require repayment of gains.

The draft rule also promotes efficiency by avoiding the administrative cost to both participants and AEMO of processing individual adjustment claims. Adopting a consistent approach to the compensation of energy and FCAS will avoid distortionary market signals which could undermine the case for investment in technologies that provide frequency services at a time when the need for such services is growing.

Further, by adopting an approach to compensation that focuses on dispatch targets in both the dispatch run and intervention pricing run, the draft rule ensures that compensation is calculated based on consistent metrics and removes the potential for compensation to be paid to participants which have not followed dispatch targets. Implicitly rewarding such behaviour would not support the efficient functioning of the market.

Incorporating the compensation of FCAS losses and gains into the process already used for energy (with some adjustments) ensures that the operation of the framework is transparent and predictable. Rather than ad hoc adjustment claims being made by individual participants (as per the AEMO proposal), the process will be predictable and the manner in which compensation is calculated based on clear formulae. By contrast, the manner in which adjustment claims are processed is not based on a formulaic approach. Instead this is a matter for AEMO (or, for larger claims, an independent expert) to determine on a case by case basis.

Finally, the draft rule makes clear which participants are "affected" and the manner in which AEMO is to calculate affected participant compensation (based on dispatch targets in the dispatch run and intervention pricing run). This will avoid uncertainty about how such compensation is to be calculated and may reduce the number of adjustment claims.

The Commission concludes that the more preferable draft rule will better contribute to the achievement of the NEO.

5 COMPENSATION FOR SCHEDULED LOADS AFFECTED BY INTERVENTIONS

This chapter examines AEMO's request to amend the formula used to calculate compensation for scheduled loads which are dispatched differently as a result of an intervention event to address a shortage of energy or market ancillary services. It sets out the issues raised by the rule change request, stakeholder views and the Commission's analysis and conclusions.

There are five main elements of the Commission's draft determination:

- The formula for scheduled load compensation should be amended so that it is based on a volume-weighted approach across scheduled load bid bands.
- Scheduled load compensation with respect to energy costs should continue to be a one-way process, such that no compensation will be payable by scheduled loads to AEMO.
- Scheduled load compensation should include FCAS (as well as energy) and this should be a two-way process, consistent with the proposed approach to FCAS compensation for affected participants.
- The calculation of scheduled load compensation should not be automatically adjusted to take account of changes to FCAS liabilities.
- Double dipping in relation to compensation should be ruled out, that is the situation where two separate participants are registered with respect to the one unit (e.g. a large scale battery) and both (in their distinct capacity as scheduled generator or scheduled load) are eligible for compensation with respect to the one unit and one intervention event.

5.1 How scheduled loads are dispatched in the NEM

AEMO has submitted a rule change request seeking to amend the definition of BidP, an input in the formula used to calculate compensation for scheduled loads which are dispatched differently as a result of an intervention event to address a shortage of energy or FCAS (i.e. an intervention event which triggers intervention pricing).

Before considering whether the definition of BidP should be amended in the manner proposed by AEMO, it is important to understand how scheduled loads are dispatched in the NEM and, in particular, how their treatment differs to that of generators.

BOX 2: HOW SCHEDULED LOADS ARE DISPATCHED IN THE NEM

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* 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. 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 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). 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 other words, unlike energy, scheduled loads and generators bid FCAS in the same manner.

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.

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.

For a scheduled load to be dispatched, the bid band price must be higher than the regional reference price (spot price). If the bid band price is lower than the spot price, the load will not be dispatched because the spot price was not low enough to justify consumption in those bands.

While generation output increases as the spot price rises, scheduled load consumption increases as the spot price falls. The total amount of energy consumed changes based on the level at which scheduled loads are dispatched. By contrast, if a generator changes its position, the amount of demand does not change. A sample scheduled load dispatch bid structure and worked example are set out in Appendix E.

Source: AEMC and AEMO, *Guide to scheduled loads*.

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

As discussed in chapter 1, the formula used to determine compensation for scheduled loads affected by interventions is:

Compensation per trading interval = ((RRP[141]x LF[142])) - BidP) x QD[143]

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 which triggers intervention pricing.[144] In particular, AEMO proposes to replace the current definition of BidP ("the price of 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").

The Commission 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 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. This means that changing the rule in the manner proposed would not change the

141 Regional reference price.

142 Applicable loss factor.

143 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.

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

compensation outcome and achieve AEMO's desired objective of avoiding under-compensation.

The consultation paper suggested 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 considering the application of this formula, the consultation paper noted that 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 advised the Commission that QD is calculated by taking as the reference point the amount of energy *actually* consumed by the load during the intervention event based on metering data. 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 equals actual consumption (broadly, the dispatch run consumed MW) minus the intervention pricing run 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.

The Commission understands that AEMO does not compensate any QD negative scenario as it considers AEMO should not pay for opportunity losses where the intervention price was lower than the dispatch price so the scheduled load could have been dispatched more but wasn't.

The consultation paper sought stakeholder views on whether the definition of BidP should be amended and if so how, and whether there would be benefit in clarifying the meaning of QD in the formula set out in clause 3.12.2(a)(2).

5.3 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 sought to ensure that such participants are not under compensated as a result of the definition of BidP, another factor that may cause such parties to be under-compensated is 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), the consultation paper noted that 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 in clauses 3.15.8 and 3.15.10C which presume that compensation for scheduled load deals with FCAS in addition to energy.[145]

It would also create consistency for pumped hydro and batteries that are currently registered as both generators and scheduled loads, and reduce the potential for market distortion that is created by having inconsistent compensation frameworks apply to a single bi-directional unit.[146]

The consultation paper sought stakeholder feedback on whether the compensation framework for scheduled loads should be amended to take into account impacts resulting from changes in FCAS enablement, as well as changes in the amount of electricity consumed.

5.4 Should compensation be net of costs incurred or avoided?

The consultation paper noted that, 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? 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[147]).

The consultation paper sought stakeholder views as to whether compensation for scheduled loads should be net of direct costs incurred or avoided.

145 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.

146 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, in accordance with the more preferable draft rule appended to this draft determination, FCAS). AEMO has submitted a rule change request on integrating energy storage and the AEMC initiated consultation on this request with the publication of a consultation paper on 20 August 2020: see https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem.

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

5.5 One-way or two-way compensation for scheduled loads?

AEMO stated in its rule change request that scheduled loads are entitled to receive compensation but are not required to repay any amounts to AEMO.[148] By contrast, affected participants (scheduled generators and scheduled network service providers) 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).[149]

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.

The consultation paper sought stakeholder views 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). The consultation paper suggested this could reduce the potential for market distortion arising from the different treatment of generators and loads, particularly given that both pumped hydro participants and large scale batteries operate in both modes, and reduce the net cost of compensation.

5.6 Stakeholder views

As noted in section 4.4, the Commission received ten submissions in response to the consultation paper. However only seven of the submissions commented on the issues raised in relation to scheduled load compensation. These included five submissions from market participants and two from consumer groups. As with the feedback on the question of whether affected participant compensation should include FCAS, there was a high degree of consistency across the submissions in relation to how scheduled loads should be compensated.

5.6.1 Consumer views

EUAA supported the proposal by AEMO to change the definition of BidP as the current definition may result in participants being under-compensated in certain circumstances. It considered that this change would align the rule with the compensation principle of leaving the affected participant in the position it would have been in but for the intervention. EUAA expressed the hope that, as new markets for system services emerge, the number and impact of AEMO interventions, and by default the compensation payable to affected participants, will decrease significantly.[150]

PIAC expressed support for improving the consistency, transparency, predictability and efficiency of compensation mechanisms for participants and scheduled loads affected by

148 AEMO, Rule change proposal, p. 3

149 Clause 3.12.2(a)(1).

150 EUAA, Submission to the consultation paper, p. 3.

intervention events, but was concerned that the rule change may result in considerable increased costs for consumers as it introduces a new type of compensation. It stressed that any compensation process should be transparent and consistent, reduce unnecessary costs to consumers, allocate risks to those best placed to manage them and costs to those who benefit from them (or, where a beneficiary pays approach is not possible, a causer pays approach should be adopted), and not discourage the adequate provision of necessary market services.

PIAC supported adopting a two-way compensation process to limit the net compensation paid out to affected participants and to ensure compensation sends efficient and transparent signals to market participants and scheduled loads. It supported calculating FCAS in the compensation automatically calculated by AEMO (net of any adjustment required in relation to FCAS liabilities), rather than requiring scheduled loads to lodge a claim for additional compensation to recoup FCAS losses. It noted that such changes may reduce administrative costs for AEMO and help ensure the compensation process is two-way and balanced.

It stressed that interventions by AEMO, and any compensation for them, should not discourage other market mechanisms, such as demand response, which may achieve similar outcomes at a lower cost to consumers.[151]

5.6.2 Market participant views

CS Energy supported changing the BidP definition in the manner proposed by the AEMC (i.e. referring to the lowest band from which the scheduled load is dispatched). It also supported clarifying the meaning of QD and the proposal that compensation for scheduled loads be two-way, consistent with compensation for affected participants. Given that scheduled loads are registered to provide FCAS, CS Energy supported scheduled load compensation including FCAS. It noted that this would be consistent with the approach for directed participant compensation and the proposed approach to affected participant compensation.

CS Energy also supported the proposal to compensate scheduled loads net of direct costs avoided or incurred, noting that this is consistent with the approach included for affected participants in clause 3.12.2(j)(1). It noted that, for scheduled loads, FCAS related costs would be the most likely costs incurred or avoided. CS Energy's preference was that such costs should be calculated by an automatic calculation process to reduce administrative costs but, if that is not feasible, then scheduled loads should be able to lodge an adjustment claim.[152]

ERM Power supported amending the definition of BidP to avoid both over and under-compensation of scheduled loads affected by interventions. To this end, it supported the suggestion in the consultation paper to define BidP as the value of the lowest price band

151 In this regard, the Commission notes that a final more preferable rule was published on 10 September 2020 to amend the current prescriptive hierarchy in clause 3.8.14 which requires that, in times of supply scarcity, AEMO must first dispatch all valid bids and offers, then activate the RERT before issuing directions or instructions. The final rule replaces this hierarchy with a requirement that, after dispatching all valid bids and offers (including the wholesale demand response mechanism) AEMO should choose the intervention mechanism or combination of intervention mechanisms which is effective while minimising direct and indirect costs. See AEMC, *National Electricity Amendment (Removal of intervention hierarchy) Rule 2020, Rule determination*, 10 September 2020.

152 CS Energy, Submission to the consultation paper, pp 3-4.

from which the scheduled load is dispatched. ERM Power also supported clarifying the meaning of QD and adopting a two-way approach to scheduled load compensation, consistent with the approach to affected participants. ERM Power supported the inclusion of FCAS in the compensation framework for scheduled loads, consistent with the approach for directed participants and the proposed approach to affected participants.

Consistent with the approach to affected participants, ERM Power supported netting off costs avoided or incurred as set out in clause 3.12.2(j)(1). Where possible, it considered that all costs should be calculated by an automatic calculation process to reduce administrative costs but, if that is not possible, provision should be made for the participant to lodge an adjustment claim. It noted that, in the case of scheduled loads, FCAS related costs would be the most likely costs avoided or incurred.[153]

EnergyAustralia (EA) supported a two-way approach to compensation for scheduled loads and noted that, to achieve this, changes will be needed to both BidP and QD. It also supported scheduled load compensation including FCAS. EA also supported a consistent approach as between affected participants and scheduled loads with respect to direct costs incurred or avoided. It supported the same costs being considered and the same mechanism being used to facilitate this, whether automatic or via an adjustment claim.[154]

Tesla strongly supported the need to address asymmetries between generators and loads, and across energy and FCAS compensation. It considered the compensation framework should be revised to ensure principles of technology and market participant neutrality. Consistent with this principle of technology neutrality, Tesla supported the inclusion of ancillary services prices in paragraph (j), noting that this paragraph should apply equally to generators and scheduled loads so that scheduled loads can be compensated with respect to FCAS losses, consistent with the proposed approach to generators. It also supported revising the definition of BidP to avoid under-compensation of scheduled loads affected by interventions. Tesla noted that moves are underway to better accommodate bi-directional resource providers via the rule change request regarding the integration of energy storage systems but considered that, in the interim, the NER should provide compensation for loads with respect to energy and FCAS, consistent with the approach to generators.[155]

AGL considered that the current definition of BidP is not appropriate as it can lead to under-compensation in most scenarios and also poses a risk of over-compensation. Its submission included a detailed example to demonstrate how the current definition can result in under-compensation when intervention prices are volatile.

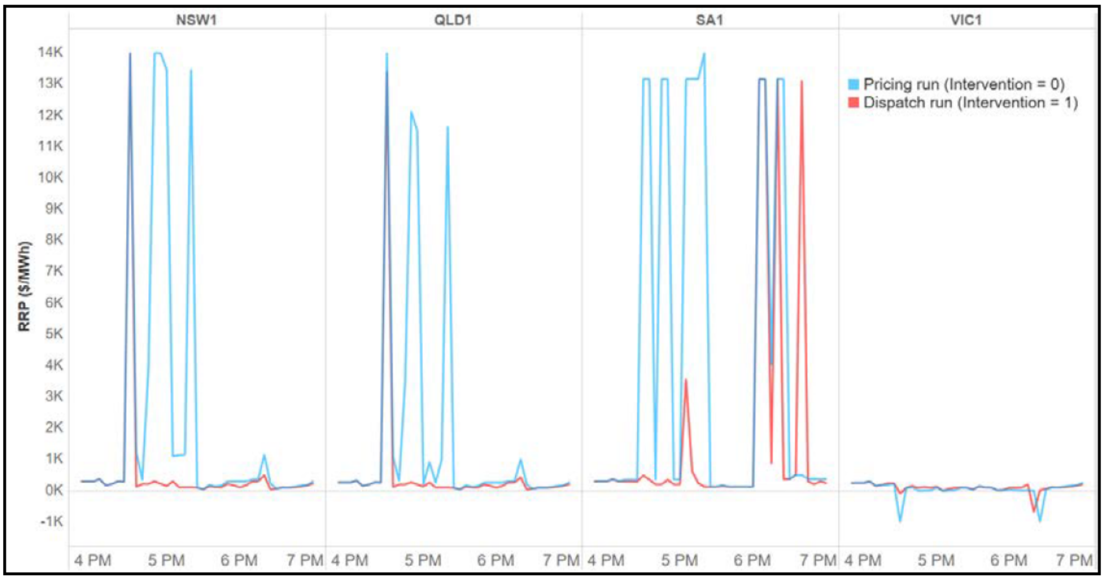
The example applied intervention prices from a trading interval on 9 February 2017, a day on which a direction to a power station in South Australia caused prices in NSW and Queensland to go to the market price cap as shown below in figure 5.1. These unexpected price outcomes prompted AEMO to initiate a review of the intervention pricing methodology and establish the Intervention Pricing Working Group.

153 ERM Power, Submission to the consultation paper, pp 2-3.

154 EnergyAustralia, Submission to the consultation paper, p. 3.

155 Tesla, Submission to the consultation paper, pp 1-2.

Figure 5.1: Prices during the 9 February 2017 intervention across NSW, QLD, SA and VIC



Source: SW Advisory and Endgame Economics, *Review of intervention pricing, Final report,* 4 October 2017, p. 19.
Note: Report available as part of Meeting 1 - meeting pack at https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/intervention-pricing-working-group

AGL used the example to show how compensation will vary depending on the approach adopted to defining BidP. It concluded by recommending a volume-weighted approach to calculating compensation. In relation to the question of whether compensation for scheduled loads should be one-way or two-way, AGL noted that it had been unable to think of situations where a scheduled load would need to repay revenue to AEMO. It considered that further analysis regarding two-way compensation was required to avoid unintended consequences for cost and settlement outcomes, particularly in view of the complexity of intervention pricing.[156]

AGL also noted that the current compensation framework allows for potential over-compensation of scheduled loads. Assuming that the scheduled load tripped after the first dispatch interval and AEMO did not receive a rebid until the completion of the trading interval, the value of QD would be negative (e.g. 0MWh actual consumption minus 25MWh hypothetical consumption in the intervention pricing run).[157] This would result in the payment of potentially significant compensation to the scheduled load in circumstances where such compensation is unwarranted. Accordingly, AGL queried whether compensation should be payable when the value of QD is negative.

AGL commented that "the intervention pricing methodology is imperfect, giving rise to anomalous and unexpected outcomes at times. Market Customers, and eventually

156 AGL, Submission to the consultation paper, p. 5.

157 This occurs because the data used in the intervention pricing run does not change to reflect that the generator has tripped. By contrast, the dispatch run is based on real time data and will reflect that the generator has tripped.

consumers, should not be exposed to the risk that scheduled loads are over-compensated during intervention pricing periods."[158]

AGL also queried whether compensation should be payable when the dispatch targets in the intervention pricing and dispatch runs are identical. In such circumstances, AGL noted that "any compensation paid though the application of metering data may be rewarding the participant for not following targets".[159] On the other hand, AGL queried the accuracy of the metering data used for the purpose of calculating compensation and suggested that QD should be calculated using settlement quality data.

In relation to FCAS, AGL supported consistent treatment of generators and scheduled loads so that, if FCAS is included in affected participant compensation, the same approach should be adopted in relation to scheduled loads. In relation to the question of whether compensation for scheduled loads should be net of direct costs incurred or avoided, AGL noted that it "has been unable to think of real-world examples of direct costs a scheduled load may incur or avoid as a result of being dispatched differently". As such, while it could see the merit in this concept as a high level principle, AGL did not support making changes in this area without further consideration of how such changes would work in practice.[160]

5.7 Analysis and conclusions

This section sets out the AEMC's further analysis and the conclusions reached in relation to the issues explored in the consultation paper and raised in stakeholder submissions.

5.7.1 How should BidP be defined?

The intention of the compensation framework in clause 3.12.2 is to put participants (whether they be loads or generators) in the position they would have been in had the intervention not occurred. This objective is currently articulated in clause 3.12.2(a)(1) in relation to affected participants but is not replicated in clause 3.12.2(a)(2) with respect to scheduled loads. The Commission has determined that clause 3.12.2 should apply the objective to both affected participants and scheduled loads. Accordingly, the draft rule includes the same objective in clause 3.12.2(a)(2).

For scheduled generators (defined as affected participants), the way that compensation is calculated is not set out in a formula, as it is for scheduled loads. Nonetheless, the effect of the current provisions in clause 3.12.2.(c)(1) can be expressed as follows.

DC = RRP x QD

where

- DC is the amount of compensation to be paid
- RRP is the intervention price (i.e. the price yielded by the intervention pricing run)

158 AGL, Submission to the consultation paper, p. 4.

159 ibid.

160 ibid, p. 5.

- QD is the difference between the amount of energy that would have been generated but for the intervention and the amount of energy actually generated.

The value of DC can be positive or negative. If it is positive, compensation is payable by AEMO to the participant (net of direct costs avoided by the participant as a result of generating less energy); if it is negative, the participant is required to repay the additional revenue earned to AEMO (net of direct costs incurred in the course of generating more energy).

Note that in the case of generators, no adjustment is made according to the generator's bids.

In the case of scheduled loads, we propose the following broad approach to calculating scheduled load compensation (leaving aside loss factors for the moment):

DC = (RRP - BidP) x QD

where

- DC is the amount of compensation to be paid
- BidP is the value of the band from which the load is dispatched
- RRP is the intervention price
- QD is the difference between the energy consumed by the load based on dispatch targets in the dispatch run and the amount of energy that the load would have consumed based on dispatch targets in the intervention pricing run (i.e. what it would have consumed but for the intervention).

As can be seen, the difference between the scheduled generator and affected participant formulas is BidP, an input that is designed to reflect the value of the load that was (or was not) consumed as a result of the intervention.

Currently, BidP is defined as "the price of the highest priced *price band* specified in a *dispatch bid* for the *scheduled load* in the relevant *intervention price trading interval".* Importantly, this definition focuses on a single band and, in particular, the highest band from which a scheduled load will be dispatched. When a scheduled load is dispatched, the first band to be dispatched will of necessity be the highest band in the load's dispatch bid.

The Commission has determined that, in contrast to the current approach, scheduled load compensation should be calculated based on a volume-weighted approach that treats all bid bands independently of one another. That is, there should be no difference between the total compensation paid to three loads each with a bid in one bid band, and a single load with equivalent bids in three bid bands.

In addition, the Commission has determined that only those values for DC which are positive should be included in the calculation of compensation (explained further below).

Accordingly, the draft rule includes the following formula:[161]

> $DC = \Sigma b \epsilon B \max (0,((RRP \times LF) - BidP_b) \times QD_b)$
>
> Where:
>
> - DC (in dollars) is the amount the Market Customer is entitled to receive in respect of that scheduled load for the relevant intervention price trading interval;
> - ΣbϵB represents the sum over each price band "b" in the set of all non-zero price bands for the scheduled load "B".
> - max(0,x) represents the maximum of the two values 0 and x.
> - 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 where the scheduled load's connection point is a transmission connection point, is the relevant intra-regional loss factor at that connection point or where the scheduled load's connection point is a distribution network connection point, is the product of the distribution loss factor at that connection point multiplied by the relevant intra-regional loss factor at the transmission connection point to which it is assigned;
> - b represents each price band in the set "B" of all price bands for the scheduled load in the relevant intervention price trading interval.
> - $BidP_b$ (in dollars per MWh) is the price offered by the scheduled load in the price band "b" in the relevant intervention price trading interval;
> - QD_b (in MWh) is the difference between the amount of electricity consumed by the scheduled load in that price band during the relevant intervention price trading interval (based on the dispatch targets for that trading interval determined through the central dispatch process used to dispatch Market Participants) and the amount of electricity which AEMO reasonably determines would have been consumed by the scheduled load in that price band if the AEMO intervention event had not occurred (based on the dispatch targets for that trading interval determined through the central dispatch process used to set prices under clause 3.9.3(b)),
>
> provided that if DC or QD_b is negative for the relevant intervention price trading interval, then the adjustment that the Market Customer is entitled to in respect of that scheduled load for that intervention price trading interval is zero.

The proposed treatment of loads is somewhat different to the treatment of generators for reasons set out below.

Suppose that:

- a load of 100 MW is bid in at $1,000/MWh,

161 Note that in the formula, max (0,x) is equal to x whenever x is positive and 0 whenever x is negative. In relation to the definition of QD_b, the amount of electricity consumed by the scheduled load, and the amount which AEMO reasonably determines would have been consumed by the scheduled load, are determined by AEMO based on the dispatch targets in the dispatch run and the intervention pricing run respectively. The dispatch run and intervention pricing run are not defined terms in the NER and hence are not used in defining QD_b.

- due to an intervention event, the dispatch run price is $500/MWh but the intervention price is $10,000/MWh.

In this case, the load of 50MWh[162] will be dispatched (because the bid price of $1,000/MWh is higher than the dispatch run price of $500/MWh) but the market will clear based on the intervention pricing run price, not the dispatch run price. Accordingly, the scheduled load will be required to pay $10,000/MWh, leading to a total cost of $500,000, even though it was only willing to pay $50,000.

This means that the scheduled load has overpaid in the amount of $450,000. It follows that to make the participant whole, compensation needs to be paid back to the scheduled load in the amount of $450,000. This financial transfer re-balances the ledger to make good the fact that the scheduled load has overpaid as a result of the application of intervention pricing. In other words, the compensation accounts for the fact that the scheduled load was dispatched (in the dispatch run) even though it would not have chosen to be dispatched at the price yielded by the intervention pricing run. As such, this adjustment protects scheduled loads from unwarranted over-payment.

This approach can be expressed as:

DC = ($10,000 per MWh - $1,000 per MWh) x (50MWh - 0MWh).

Note that because the load derives value from being dispatched, which we assume to be BidP (i.e. its willingness to pay in $ per MWh), compensation is not payable for the whole value paid by the load (i.e. $500,000). Paying the full amount would constitute over-compensation.

How does this volume-weighted approach differ from the current Rules?

Under the current rules, if a load bids in multiple bands, BidP is the price of the highest priced price band. It follows that even if just a single MW is placed in a high band, BidP is assumed to be equal to that value for all bands**.** The effect of this is to make affected participant compensation for scheduled loads negative (and so treated as zero) most of the time. This is clearly the wrong approach, because it does not follow the principle of putting the scheduled load in the position that it would have been in but for the intervention.

The Commission considers that the approach adopted in the draft rule strikes a fair balance between the interest of scheduled loads and of those market participants and consumers which bear the cost of compensation. The issue of which parties bear the cost of compensation will depend on the nature of the intervention that gave rise to the payment of compensation under clause 3.12.2. If the intervention comprised a RERT activation or direction to address a shortage of energy, compensation costs will be passed through to market customers and ultimately consumers. If the intervention comprised a direction to address a shortage of FCAS, compensation costs will be recovered in the same manner as the original service the subject of the direction.

5.7.2 Should compensation be one-way or two-way?

No compensation is payable where DC is negative

162 Being 100MW of load dispatched for thirty minutes.

Where the value of DC is negative, scheduled *generators* are required to repay revenue to AEMO – consistent with a two-way approach to compensation (compensation for loss, repayment of gains). The consultation paper asked whether the same two-way compensation approach should apply to scheduled *loads*. Several stakeholders submitting to the consultation paper (CS Energy, ERM Power, EnergyAustralia) supported this view while others did not (AGL and Tesla). The Commission has now undertaken further analysis on the basis of which it has determined that a two-way approach to energy compensation is not appropriate for scheduled loads.

The Commission has considered how to treat a situation where DC (the value of compensation) is negative. For DC to be negative in the proposed scheduled load compensation formula, the value of the price band from which the load is dispatched (BidP – e.g. $10,000) would need to be higher than the spot price (RRP – e.g. $2,000). Alternatively, the value of QD (the difference between the energy actually consumed and the amount that would have been consumed but for the intervention) would need to be negative - an issue that is discussed further below.

Suppose to begin with that QD is positive. Note that QD will be positive where the energy actually consumed is greater than the amount of energy that would have been consumed but for the intervention. This will typically be the case because the dispatch run price will generally be lower than the intervention price, and scheduled load consumption increases as the spot price falls.

Now suppose that there is a price band for which (RRP - BidP) is negative: that is, the price the load is willing to pay (e.g. $1,000/MWh) exceeds the price at which the load was actually dispatched (e.g. $200/MWh). Should compensation be payable by the scheduled load to AEMO in this circumstance?

The Commission considers that compensation should not be payable by the scheduled load to AEMO in this situation. The formula in question was not designed to apply in circumstances where (RRP - BidP) is negative. To apply such a formula would effectively be saying that scheduled loads should pay back as compensation the surplus that they derived from consuming electricity, which is effectively a "pay-as-bid" approach to determining compensation. By contrast, compensation for scheduled generators is based not on how the generators bid but on how they are cleared (i.e. a "pay-as-cleared" rather than "pay-as-bid" approach).

The Commission has determined that compensation should not be payable for consuming energy at a price that is lower than a scheduled load would have been willing to pay for it. In effect, the question "what compensation is payable by a load that consumes more energy than it otherwise would have, at a price it is willing to pay?" yields the answer "none".

Accordingly, the Commission has determined that adopting a two-way approach to energy compensation for scheduled loads would not be appropriate and would create perverse outcomes for scheduled loads. As such, the draft rule retains the current provision stating that, where the value of DC is negative, it will be set to zero (meaning no compensation is payable by the scheduled load to AEMO). This approach is consistent with the detailed submission from AGL which noted that it could not think of a scenario in which it would be appropriate to require scheduled loads to repay revenue to AEMO.

No compensation is payable where QD is negative

The Commission has also determined that the draft rule should provide that, where QD_b is negative, no compensation will be payable. This is proposed because, for QD_b to be negative, a scheduled load must consume more energy in the intervention pricing run than in the dispatch run. This will only happen in circumstances where the price difference is also negative: i.e. the intervention price is lower than the dispatch run price.

The question of whether compensation should be payable when QD_b is negative hinges on what it means for QD_b to be negative. Suppose that:

- the intervention price is $100/MWh and the dispatch run price is $300/MWh.
- a load of 100 MW is bid to be dispatched at $200/MWh, and so is not dispatched in the dispatch run, but would have been dispatched in the intervention price run
- so the load is not dispatched even though it should have been, leading to a loss of ($100 x 50 MWh= $5,000).

Such outcomes are anomalous and generally occur due to, for example, constraints binding in unintended ways in the intervention pricing run.[163] A negative value for QD_b will be associated with a negative value for (RRP- BidP). Multiplying these two negative values will produce a positive value for DC. Nonetheless, the Commission has determined that compensation should not be payable where QD_b is negative.

This is consistent with AEMO's current practice when it calculates compensation for scheduled loads. It is also consistent with the submission from AGL which noted that scheduled loads could be over-compensated when QD is negative. For example, if a scheduled load trips, its consumption in the dispatch run will fall to zero but remain the same in the intervention pricing run until the scheduled load rebids. Paying compensation to the scheduled load in such circumstances is not warranted and would unnecessarily increase costs to consumers.

The Commission concludes that symmetry between generators and loads is not appropriate with respect to energy compensation due to the different manner in which generators and loads are dispatched for energy. However, as discussed further below, a consistent two-way approach has been adopted in relation to compensation for FCAS gains and losses because generators and loads are dispatched in the same way with respect to FCAS.

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

The Commission has determined that scheduled load compensation should comprise both energy and FCAS, consistent with the approach to affected participants. To do otherwise would create asymmetry in the compensation frameworks that apply to scheduled loads and

163 Intervention pricing is designed to preserve scarcity price signals which would otherwise be muted as a result of an intervention event. Normally, the intervention price is higher than the dispatch run price. This is because the intervention pricing run excludes units which have been directed on and/or the effect of the RERT. As such, the supply demand balance in the intervention pricing run remains "tight" and prices high, compared with the situation in the dispatch run where the supply demand balance is less tight and prices are lower.

scheduled generators. Such asymmetry would be particularly inappropriate given the growing number of bi-directional resource providers in the NEM: that is, units which can both consume and generate electricity (e.g. large scale batteries and pumped hydro) and are important providers of frequency control services (as demonstrated in the recent islanding of the South Australian region, a point noted by Tesla in its submission[164]).

As noted in section 3.4.1, the generation fleet is undergoing a rapid transition and inertia levels are falling, making the provision of frequency services increasingly important to maintain system security. In December 2019, the Commission made a rule change which narrowed the circumstances in which compensation for affected participants and scheduled loads is payable. As a result, such compensation is no longer payable with respect to security interventions (such as system strength directions) but is still payable when an intervention event triggers intervention pricing (i.e. when an intervention event is to address a scarcity of energy or FCAS).

The Commission noted that, when AEMO intervenes due to a scarcity of energy or FCAS (thereby triggering intervention pricing), prices will generally be high, providing participants with important revenue-earning opportunities. If a participant is affected by an intervention event during such periods, the Commission considered that it is reasonable to keep such participants "whole" through the payment of compensation under clause 3.12.2 (balanced by the requirement to repay any additional revenue earned). Such an approach was determined to be in the long term interests of consumers as it will support the ongoing viability of participants providing important services to the market.[165]

The Commission has examined the potential cost implications of including FCAS in the compensation framework for scheduled loads. As previously noted, such analysis is complex because it involves netting out a number of counterveiling factors. For example, changes to raise FCAS service enablement targets may be offset by changes to lower FCAS service enablement targets, potentially producing a net compensation outcome that is lower than would have occurred absent this dynamic.

In addition, the draft rule adopts a two-way approach to compensating scheduled loads with respect to FCAS, consistent with the current calculation of affected participant compensation with respect to energy (and the proposed approach to FCAS compensation for affected participants). This means that the cost of compensating scheduled loads with respect to changes in FCAS revenue that is passed through to other market participants and consumers will be the net amount taking into account compensation payments by AEMO to scheduled loads, and revenue paid back to AEMO by scheduled loads.

Finally, total compensation payments to scheduled loads will be the sum of energy compensation (which will always be a positive amount, consistent with a one-way approach to compensation) and FCAS compensation (which can be positive or negative, consistent with a two-way approach to compensation). Where the value of FCAS compensation is negative,

164 Tesla, Submission to the consultation paper, p. 1

165 AEMC, *Application of compensation in relation to AEMO interventions, Rule determination*, 19 December 2019, pp iv and 37.

this will serve to reduce the total compensation paid to scheduled loads (and may bring the quantum payable below the $5,000 threshold, meaning that no compensation is to be paid).

5.7.4 Should compensation be net of costs incurred or avoided?

The consultation paper asked whether scheduled load compensation should be net of direct costs incurred or avoided as a result of the intervention event, consistent with the approach to affected participant compensation (as set out in clause 3.12.2(j)). In particular, the consultation paper suggested it may be appropriate to consider FCAS liabilities (noting that scheduled loads are required to contribute to the cost of regulation FCAS having regard for the total energy consumed in a trading interval[166]).

The consultation paper noted that, subject to considerations of administrative complexity and cost, changes to FCAS liabilities could be incorporated either through the automatic calculation of compensation by AEMO or via an adjustment claim lodged under clause 3.12.2(f).

Several stakeholders submitting to the consultation paper (CS Energy, ERM Power, EnergyAustralia) expressed support for this approach and noted that, if it is not cost effective for AEMO to calculate such changes in liability automatically, scheduled loads should have the option to lodge an adjustment claim in order to recoup losses arising from increased FCAS liabilities.

The Commission has considered this issue further and concluded that it is not efficient to incorporate FCAS liability adjustments as part of the automatic calculation of affected participant compensation. The data used to calculate FCAS liabilities is dynamic: it changes to reflect not only the varying costs of FCAS services over time, but also the changing causer pays contribution factors which determine how the cost of regulation FCAS services is apportioned to market participants.

While the data used to calculate scheduled load compensation is drawn from the market management system (MMS), the data needed to calculate FCAS liabilities sits outside the MMS. Combining the two systems to recalculate liabilities automatically would be complex and, during normal operating conditions, would likely have limited impact on the compensation payable to scheduled loads. Accordingly, the draft rule does not include a provision requiring AEMO to take into account changes in FCAS liabilities when determining the quantum of energy and FCAS compensation payable to scheduled loads. However, existing paragraph (f) and amendments to paragraph (j) in clause 3.12.2 will allow scheduled loads to lodge an adjustment claim if they consider that their compensation (or liability to repay revenue) should be redetermined. By incorporating a reference to scheduled loads in

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

paragraph (j), the more preferable draft rule makes this part of the compensation framework appropriately consistent with the approach to compensating affected participants.[167]

While paragraph (j) refers to direct costs such as fuel costs, incremental maintenance and manning costs, this list of factors is inclusive rather than exhaustive. As such, a scheduled load could seek an adjustment having regard for the items set out in paragraph (j), namely: direct costs incurred or avoided as a result of the AEMO intervention event, any amounts which the participant is entitled to receive under clauses 3.15.6 and 3.15.6A, the regional reference price, and ancillary service prices.

In a similar way to clause 3.12.2(f) and (j), clause 3.15.7B enables directed participants to lodge a claim for additional net direct costs and loss of revenue where such participants are still out-of-pocket following the automatic calculation of compensation under clause 3.15.7. As noted in chapter 4, a South Australian generator recently lodged a claim for additional directed participant compensation which included a claim to recoup the additional FCAS charges that the generator incurred as a result of compliance with the direction. The claimant noted that it would not have incurred these charges had they not been directed. The independent expert engaged to determine the claim agreed that the costs were incurred as a result of the direction and should be compensated.[168] Having regard for this example, it may be open to a scheduled load to lodge an adjustment claim in the event that changes to its dispatch targets resulted in a material change in its FCAS liabilities (noting that an adjustment claim can only be lodged if it exceeds the $5,000 compensation threshold set out in clause 3.12.2(i)).

Given that intervention events which trigger intervention pricing are generally of short duration (e.g. four to six hours), the Commission does not anticipate that scheduled loads (as distinct from directed participants) would often experience changes in FCAS liabilities which exceed the $5,000 threshold. As such, the ability to lodge a claim to recoup increased FCAS liabilities (without a corresponding obligation to repay reductions in FCAS liabilities) is not expected to result in significant additional compensation costs being passed through to other market participants and consumers.

5.7.5 Double dipping

The more preferable draft rule includes a new paragraph (b1) which provides that an affected participant or market customer is not entitled to compensation under clause 3.12.2 with respect to scheduled plant for an intervention price trading interval if AEMO is required to pay compensation under clauses 3.15.7, 3.15.7A or 3.15.7B with respect to that scheduled plant and intervention price trading interval. That is, it removes the possibility for claiming compensation effectively twice (double dipping) by market participants.

167 The Commissions notes that the words "scheduled load" have not been included in subparagraph (j)(1)(i) relating to fuel costs since such costs are not relevant for scheduled loads. However, sub-paragraphs (ii) and (iii) have been amended to include a reference to scheduled load. It may be, for example, that changes to a scheduled load's dispatch targets are such as to create additional wear and tear which may bring forward maintenance costs. Where such costs are material (exceeding the $5,000 threshold), an adjustment claim could be lodged. While this is not considered likely, the Commission considers that compensation frameworks for scheduled generators and scheduled loads should be consistent to the extent that is warranted and appropriate.

168 IES, Direction to participants in South Australia in March 2020, Draft determination report, 14 July 2020, p. 5.

This is designed to prevent a situation where two separate participants are registered with respect to the one unit (e.g. a large scale battery) and both (in their distinct capacity as scheduled generator or scheduled load) are eligible for compensation with respect to the one unit and one intervention event. For example, AEMO could issue a direction to a scheduled generator to discharge its battery to provide MW and/or FCAS raise services. AEMO would compensate the generator for its services in accordance with clause 3.15.7 and, if need be, pay additional compensation under clause 3.15.7B.

The market customer which is registered with respect to the same battery (in terms of consumption rather than generation of energy) could say that it was not the subject of the direction but it was dispatched differently as a result of the direction and thus is entitled to compensation for its loss of revenue. Such a situation would result in additional compensation costs being passed through to other market participants and consumers and would be contrary to the NEO.

The Commission notes that the rules do include provisions which seek to avoid this situation arising. For example, clause 3.12.2(a)(2) states that a market customer, *other than a market customer which was the subject of any direction that constituted the AEMO intervention event*, is entitled to receive an amount calculated in accordance with the formula set out. The issue is that, as per the above example, the direction was not issued to the market customer but to the scheduled generator. As such, this clause is not well suited to accommodate bi-directional resource providers where two market participants (scheduled generator and scheduled load) are required to be registered with respect to the one unit.

Similarly, the definition of affected participant in chapter 10 of the NER states (in part) that a scheduled generator is an affected participant if it was not the subject of the direction and had its dispatched quantity affected by that direction. If the above example were reversed, the scheduled generator could say it was not the subject of the direction (which was issued to the scheduled load) and had its dispatched quantity affected by that direction. As such it is entitled to compensation under clause 3.12.2.

Directions issued to South Australian batteries during the recent islanding event highlight the potential for confusion in this area. Following the directions (which included directions for FCAS and for "other services" – e.g. maintaining a state of charge), AEMO engaged an independent expert (IES) to determine the compensation payable under clause 3.15.7A with respect to the "other services" directions.

The IES report noted that "Claimant 2", which had received directed participant compensation with respect to the generator side of the battery, also sought an amount of $36,749.09 which "was characterised by Claimant 2 as Loss of Affected Participant compensation referencing 3.15.7B(a3)(7). Claimant 2's reasoning for this component was that L2 would have received Affected Participant compensation had it not been for the direction."[169]

If a directed participant considers it is still "out-of-pocket" following receipt of compensation under clause 3.15.7 (based on the 90th percentile price) or clause 3.15.7A (fair payment price

169 IES, *AEMO Directions to Participants in South Australia on 2 and 4 February 2020, Final determination,* 19 August 2020, p. 6.

compensation for "other services" directions), it can lodge a claim for additional compensation under clause 3.15.7B. A directed participant is entitled to claim "the aggregate of the loss of revenue and additional net direct costs incurred by the Directed Participant … as a result of the provision of the service under direction".

Clause 3.15.7B(a3) sets out the kinds of additional net direct costs that a directed participant can claim. Costs listed in clause 3.15.7B(a3) include fuel costs, incremental maintenance and staffing costs, maintenance acceleration or delay costs, and other costs incurred to enable the unit to comply with the direction.

In contrast to these categories of costs, clause 3.15.7B(a3)(7) refers to "any compensation which the Directed Participant receives or could have obtained by taking reasonable steps in connection with the relevant generating unit or scheduled network services being available". The reference to compensation received or able to be obtained means that this is not a "cost" as such, unlike the items listed in the preceding subparagraphs. It is not clear what subparagraph (7) is intended to achieve but it is evident from the IES report that directed participants are seeking to rely on this clause in order to claim affected participant compensation.

IES considered that Claimant 2's submission "contained incorrect references to subclauses or incorrect reference to Affected Participant…. The reference to 3.15.7B(a3)(7) is also incorrect in that the claim relates to a revenue loss or gap rather than to a direct cost. The gap in revenue resulted from the directed enabled amount being lower than the what-if enabled amount would have been in the absence of the direction. The loss of revenue was calculated by Claimant 2 based on the what-if price and the difference between the what-if enabled MW and the enabled MW under the direction. The what-if MW quantities and what-if prices are determined by AEMO, as required by the NER, in a separate run (intervention/outturn run). As a revenue loss, this amount is also more correctly referenced to 3.15.7B(a)(1)."[170]

The Commission has determined that this uncertainty should be resolved and that, where two participants are registered with respect to a single unit, they should not be able to obtain both directed participant compensation and compensation under clause 3.12.2. To address this, the Commission has determined that compensation will not be available under clause 3.12.2 where it is already being paid with respect to a given unit under the directed participant compensation framework. That framework allows directed participants to seek compensation for loss of revenue, and this is essentially the same calculation as would be made under clause 3.12.2.

To avoid confusion and prevent double dipping, the more preferable draft rule includes a new paragraph (b1) in clause 3.12.2 which provides that an affected participant or market customer is not entitled to compensation under clause 3.12.2 with respect to scheduled plant for an intervention price trading interval if AEMO is required to pay compensation under clauses 3.15.7, 3.15.7A or 3.15.7B with respect to that scheduled plant and intervention price trading interval. Given the inclusion of this new provision, the more preferable draft rule

170 ibid.

deletes clause 3.15.7B(a3)(7) as it is no longer required and its retention would likely result in ongoing confusion as to its role and meaning.

The Commission considers that these changes better achieve the NEO, create transparency and predictability, and reduce the potential for confusion as to the manner in which compensation should be calculated.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	See AEMC
FCAS	Frequency control ancillary services
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 LEGAL REQUIREMENTS UNDER THE NEL

This appendix sets out the relevant legal requirements under the NEL for the AEMC to make this draft rule determination.

A.1 Draft rule determination

In accordance with s. 99 of the NEL, the Commission has made this draft rule determination in relation to the rules proposed by AEMO.

The Commission's reasons for making this draft rule determination are set out in sections 3.4.

A copy of the more preferable draft rule is attached to and published with this draft rule determination. Its key features are described in sections 3.1.1 to 3.1.3.

A.2 Power to make the rule

The Commission is satisfied that the more preferable draft rule falls within the subject matter about which the Commission may make rules. The more preferable draft rule falls within s. 34(1)(a)(i) and (iii) of the NEL as it relates to regulating the operation of the national electricity market and the activities of persons participating in the national electricity market.

A.3 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the rule
- the rule change request
- submissions received during first round consultation
- the Commission's analysis as to the ways in which the proposed rule will or is likely to, contribute to the NEO.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[171]

The Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed rule is compatible with the proper performance of AEMO's declared network functions.[172] The more preferable draft rule is compatible with AEMO's declared network functions because it is unrelated to them and therefore it does not affect the performance of those functions.

171 Under s. 33 of the NEL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy. On 1 July 2011, the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. The amalgamated council was formerly called the COAG Energy Council and is now the ministerial forum of Energy Ministers.

172 Section 91(8) of the NEL.

A.4 Civil penalties

The Commission cannot create new civil penalty provisions. However, it may recommend to the ministerial forum of Energy Ministers (formerly COAG Energy Council)[173] that new or existing provisions of the NER be classified as civil penalty provisions.

The draft rule does not amend any clauses that are currently classified as civil penalty provisions under the NEL or National Electricity (South Australia) Regulations. The Commission does not propose to recommend to the ministerial forum of Energy Ministers (formerly COAG Energy Council) that any of the proposed amendments made by the draft rule be classified as civil penalty provisions.

A.5 Conduct provisions

The Commission cannot create new conduct provisions. However, it may recommend to the ministerial forum of Energy Ministers (formerly COAG Energy Council) that new or existing provisions of the NER be classified as conduct provisions.

The draft rule does not amend any rules that are currently classified as conduct provisions under the NEL or National Electricity (South Australia)Regulations. The Commission does not propose to recommend to the ministerial forum of Energy Ministers (formerly COAG Energy Council) that any of the proposed amendments made by the draft rule be classified as conduct provisions.

173 On 29 May 2020, the Prime Minister announced the establishment of the National Federation Reform Council and the disbanding of COAG. New arrangements for the former COAG Energy Council will be finalised following the National Cabinet Review of COAG Councils and Ministerial Forums which is due to provide recommendations to National Cabinet by September 2020. The Prime Minister has advised that, while this change is being implemented, former Councils may continue meeting as a Ministerial Forum to progress critical and/or well developed work.

B 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,
- how participants bid FCAS into the market, and
- how units can become "trapped" in their FCAS trapeziums.

B.1 The eight FCAS markets

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.[174]

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.[175]

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

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

TYPE OF SERVICE	MARKET	FUNCTION	WHO BEARS THE COST?
Regulation	Regulation Raise	Regulation service used to correct a minor drop in frequency	Causer pays procedure
	Regulation Lower	Regulation service used to correct a minor rise in	Causer pays procedure

174 AEMO, *Guide to ancillary services in the National Electricity Market*, April 2015, p. 4.

175 ibid.

TYPE OF SERVICE	MARKET	FUNCTION	WHO BEARS THE COST?
		frequency	
Contingency	Fast Raise (6 Second Raise)	6 second response to arrest a major drop in frequency following a contingency event	Market generators or market small generation aggregators
	Fast Lower (6 Second Lower)	6 second response to arrest a major rise in frequency following a contingency event	Market customers
	Slow Raise (60 Second Raise)	60 second response to stabilise frequency following a major drop in frequency	Market generators or market small generation aggregators
	Slow Lower (60 Second Lower)	60 second response to stabilise frequency following a major rise in frequency	Market customers
	Delayed Raise (5 Minute Raise)	5 minute response to recover frequency to the normal operating band following a major drop in frequency	Market generators or market small generation aggregators
	Delayed Lower (5 Minute Lower)	5 minute response to recover frequency to the normal operating band following a major rise in frequency	Market customers

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

B.2 Recovering the cost of FCAS

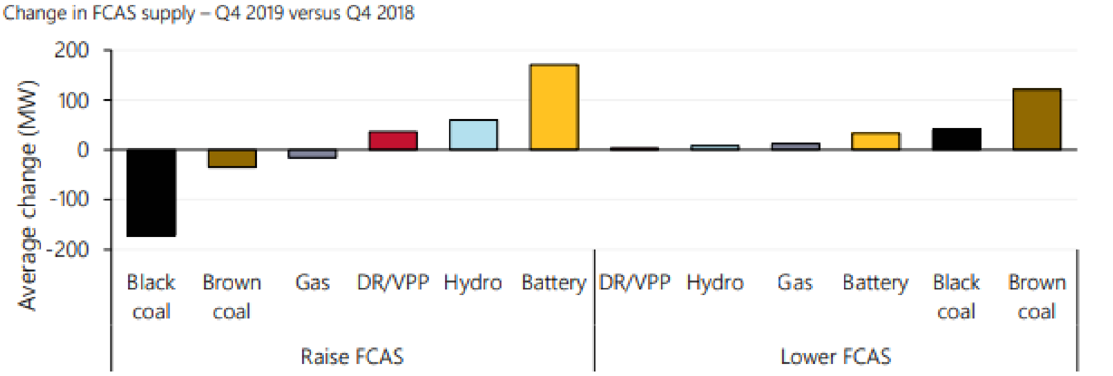
FCAS cost recovery operates differently depending on the service. For regulation FCAS, scheduled participants have contribution factors determined by the degree to which they follow their dispatch instructions. This requires telemetry that provides AEMO with high granularity information. For participants 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[176]) and increased uptake of utility scale batteries, the FCAS market is now more diverse - as shown by figure B.1. Particularly in South Australia, where a small number of

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

participants had previously exercised considerable market power, this resulted in downward pressure on FCAS prices.

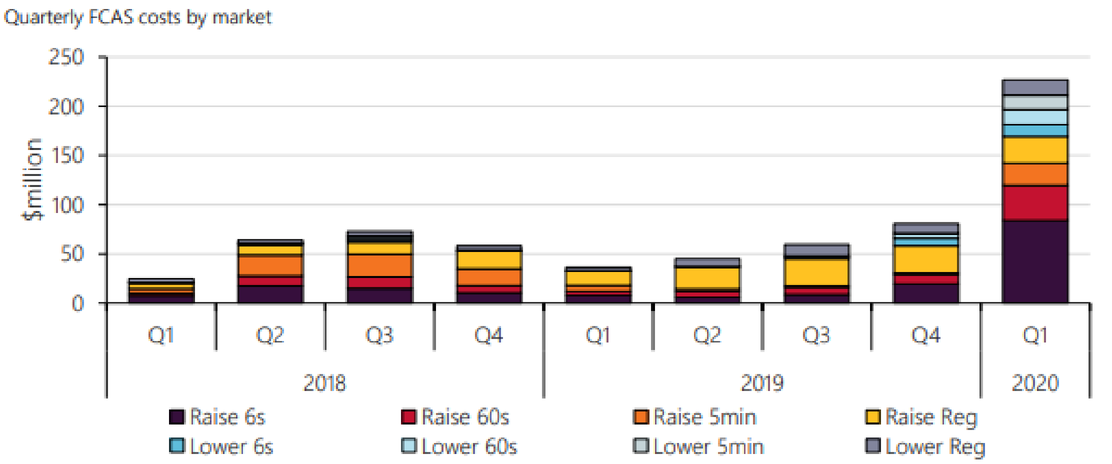
Figure B.1: The changing composition of FCAS markets



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 B.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 B.2: FCAS costs by quarter: Q1 2018 - Q1 2020



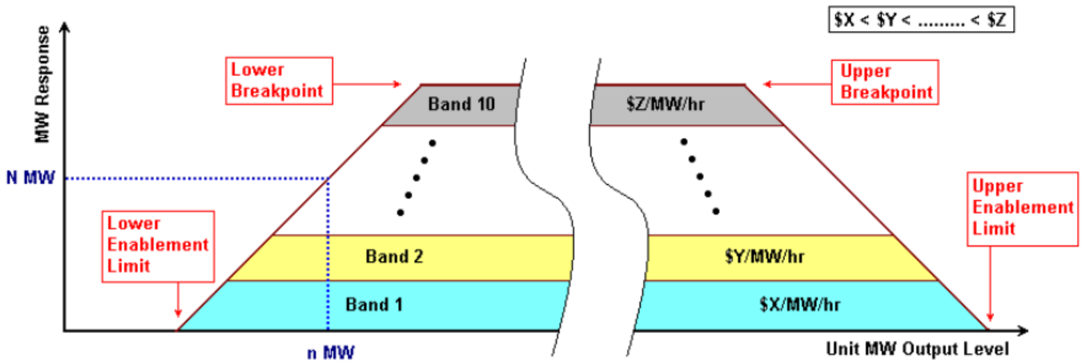
Source: AEMO, *Quarterly Energy Dynamics, Q1 2020*, April 2020, p. 25.

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.[177]

B.3 How participants bid FCAS into the market

Offers and bids for FCAS services take the form of the generic "FCAS trapezium" which is defined by enablement limits and breakpoints. The trapezium indicates the maximum amount of FCAS that can be provided (y axis) for a given MW output level for a generator, or given MW consumption level for a scheduled load (x axis). For example, a generator or load dispatched, in the energy market, at "n" MW could be enabled by NEMDE to provide up to "N" MW of the relevant FCAS.[178]

Figure B.3: Generic FCAS trapezium



Source: AEMO, Guide to ancillary services in the National Electricity Market, April 2015, p. 10.

The FCAS offers and bids must comply with similar bidding rules that apply to the energy market:

- offers/bids can consist of up to 10 bands with non-zero MW availabilities
- band prices must be monotonically increasing
- band prices must be set by 12:30 on the day prior to the trading day for which the offer/bid applies
- band availabilities, enablement limits and breakpoints can be rebid under rules similar to those applying to the energy market.

Ancillary service plant dispatched between an enablement limit and a corresponding breakpoint can be moved in the energy market in order to obtain more FCAS. For example, if

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

178 AEMO, *Guide to ancillary services in the National Electricity Market*, April 2015, p. 10.

a generator was dispatched between the upper enablement limit and the upper breakpoint, NEMDE may "constrain" the unit in the energy market in order to obtain more FCAS, provided this led to the lowest overall cost.

The generic trapezium shown above is altered to suit the various technologies that provide FCAS. For example, a load shedding service would be fully available when the load is dispatched fully in the energy market, and the availability would reduce linearly to zero as the energy dispatch point moved towards the origin. This bid shape would be achieved by setting the lower enablement limit at zero and both breakpoints and the upper enablement limit equal to the maximum energy capacity of the load.[179]

B.4 Entrapment in the FCAS trapezium

During its review of intervention pricing, AEMO identified that a generator or scheduled load can become "trapped" at the minimum or maximum enablement limits of its FCAS trapezium in the intervention pricing run.[180] This is a consequence of the way in which FCAS offers are represented in NEMDE.

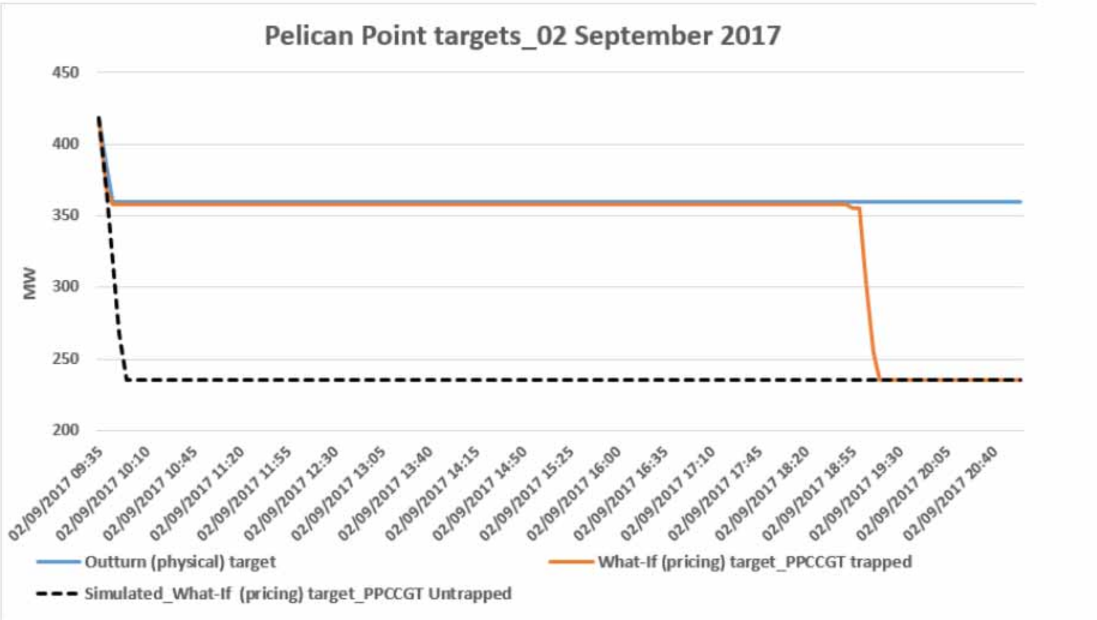
Because generators are assumed to meet their dispatch targets exactly in the pricing run, a generator trapped in the pricing run will remain trapped (unless they rebid their FCAS trapezium) until intervention pricing is revoked. In the dispatch run, that same generator may become untrapped through natural variability in its energy output.

An example of generator entrapment in the FCAS trapezium occurred on 2 September 2017 when AEMO directed Pelican Point power station to remain synchronised and follow dispatch targets in order to maintain adequate system strength in South Australia. Figure B.4 below compares Pelican Point's targets from the dispatch and intervention pricing runs (with Pelican Point trapped) on 2 September 2017 to a simulated intervention pricing run (with Pelican Point un-trapped).

179 ibid.

180 AEMO, *Intervention pricing methodology consultation, Issues Paper,* June 2018.

Figure B.4: Comparison of Pelican Point targets from dispatch and intervention pricing run on 2 September 2017 (Pelican Point trapped) and simulated run (Pelican Point un-trapped)



Source: AEMO, *Intervention pricing methodology consultation, Issues Paper,* June 2018, p. 11.

Entrapment in the FCAS trapezium has implications for both the accuracy of prices set by the intervention pricing run, and the payment of compensation to participants dispatched differently as a result of an AEMO intervention event which triggers intervention pricing. For example, if Pelican Point had been an affected participant rather than a directed participant in the intervention event of 2 September 2017, it would not have been entitled to affected participant compensation since its dispatch targets did not differ as between the dispatch run and the intervention pricing run.

After consultation with the Intervention Pricing Working Group, AEMO developed a solution which involves applying a small change to the unit's dispatch target in the intervention pricing run to move the unit's dispatch target outside the trapezium and so un-trap it.[181] AEMO has determined that the proposed change to NEMDE should be made "as resources allow". [182]

AEMO is yet to implement this solution. While this issue may occasionally impact the accuracy of affected participant compensation calculations (creating the potential for both under- and over-compensation), participants impacted by this issue could potentially lodge an adjustment claim in accordance with clause 3.12.2(f) of the NER, seeking to have their compensation or liability redetermined.[183]

181 ibid, pp 15-16.

182 AEMO, *Intervention pricing methodology, Final report and determination, September 2018,* p. 8.

183 Such claims must have a value exceeding $5,000: clause 3.12.2(i).

C 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.[184] 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.[185]

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

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

185 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.

D 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 noting and considering the approach adopted in these frameworks to the question of FCAS losses. These frameworks are discussed in turn below.

D.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.[186]

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 (or vice versa). 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.

186 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. A draft determination was published on 24 September 2020 and a final determination is scheduled to be published in December 2020. See https://www.aemc.gov.au/rule-changes/compensation-following-directions-services-other-energy-and-market-ancillary-services

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.[187] 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).

D.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.[188] 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.[189]

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, hydro, large-scale batteries) supplemented by a 15 per cent premium to account for divergences between estimated and actual costs.[190]

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.[191]

Where AEMO issues a direction to a generator during a MSPS period, the MSPS compensation framework would apply, not the directions compensation framework.[192] 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.

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

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

189 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).

190 See clause 3.14.5A of the NER.

191 See clause 3.14.5B of the NER.

192 See clause 3.15.7(d1) of the NER.

D.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.[193] 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.[194]

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 aim to 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.

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.[195]

193 When the cumulative sum of spot prices in a region across a rolling seven day period exceeds the CPT (currently set at $224,600 for 2020-21), 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.

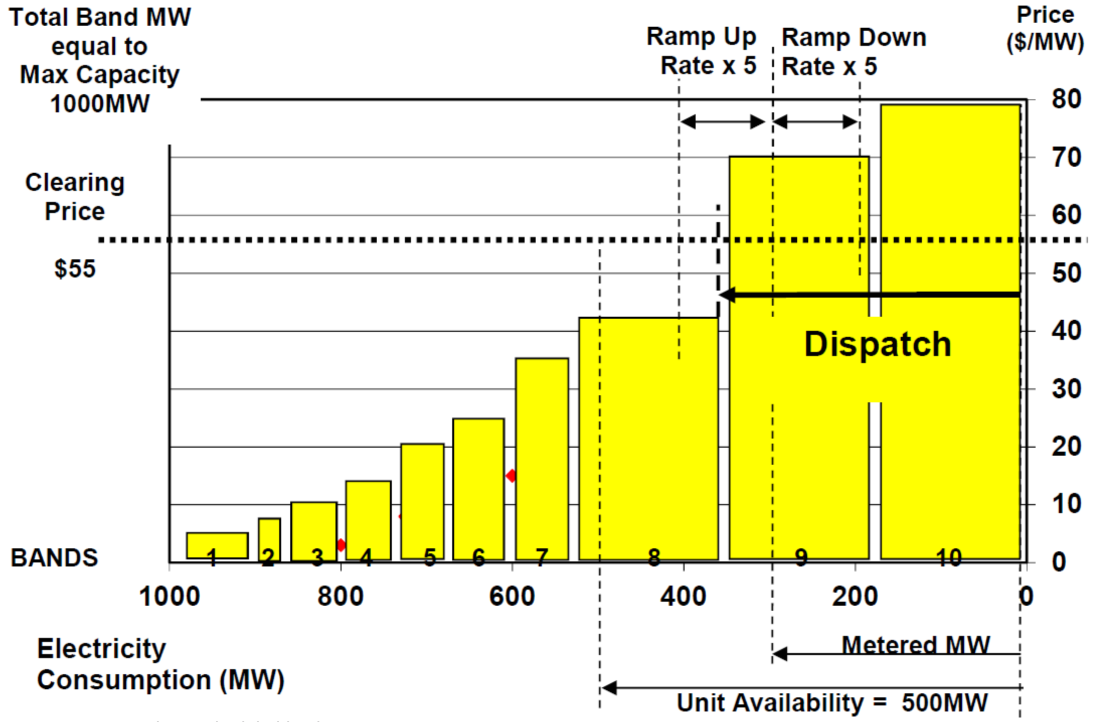
194 See clause 3.14.6 of the NER.

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

E HOW SCHEDULED LOADS BID IN THE NEM

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

Figure E.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 4: 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.