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Response to Frequency control rule changes directions paper

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4 Feburary 2021

Ben Hiron

Senior Adviser

Australian Energy Market Commission

Lodged electronically

Collaboration on Energy and Environmental Markets

Dear Mr Hiron,

Re: Frequency control rule changes directions paper

The Collaboration on Energy and Environmental Markets (CEEM) welcomes the opportunity to make a submission to the Australian Energy Market Commission's (AEMC) *Frequency control rule changes* directions paper.

About us

The UNSW Collaboration on Energy and Environmental Markets (CEEM) undertakes interdisciplinary research in the design, analysis and performance monitoring of energy and environmental markets and their associated policy frameworks. CEEM brings together UNSW researchers from a range of faculties, working alongside a number of Australian and international partners. CEEM's research focuses on the challenges and opportunities of clean energy transition within market-oriented electricity industries. Effective and efficient renewable energy integration is key to achieving such energy transition and CEEM researchers have been exploring the opportunities and challenges of market design and policy frameworks for renewable generation for several decades. More details of this work can be found at the Collaboration website. We welcome comments, suggestions, questions and corrections on this submission, and all our work in this area. Please feel free to contact Associate Professor Iain MacGill, Joint Director of the Collaboration (i.macgill@unsw.edu.au) and Dr Anna Bruce, the Engineering Research Coordinator (a.bruce@unsw.edu.au) for other CEEM matters.

Our submission

In this submission, we first provide some higher level summary thoughts on the frequency control challenge facing the Australian National Electricity Market, before responding to the specific questions posed by the AEMC in the Directions paper. Our responses are guided by our broader view of the problem, which objectives and outcomes we consider to be a priority, and what we see as the merits yet also of each solution pathway. each solution pathway.

We would of course be very happy and interested to discuss these comments further with the AEMC if that is of interest to you and your colleagues. All the best for this challenging but extremely important work, and sincere regards

Abhiijith Prakash, Iain MacGill and Anna Bruce

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Summary views on essential system services, including frequency control

The importance of effectiveness during energy transition

We see **effectiveness** (sufficient and appropriate frequency response to meet physical power system requirements), **efficiency** (productive, dynamic and allocative) and the **minimisation of procurement costs and complexity** as **outcomes of good system services design**[1]. Elements of productive, dynamic and allocative efficiency are encapsulated within the AEMC's *System services objectives* and the transparency, predictability and simplicity of procurement arrangements is one of the principles of assessment for the rule change (Section 3.4). However, we feel that **there is only an implicit reference to effectiveness in the AEMC's *System services objectives***. Effectiveness not only encompasses the service's technical definition (e.g. response time, droop, sustainment, etc.) but also the interdependency, interoperability and interchangeability between existing and potential services[2]. Effective frequency control arrangements should be able to handle variability and uncertainty in not only the present NEM but more generally a potentially wide range of future NEM configurations, in an assured and robust manner. Assured effectiveness under a range of potential future NEM configurations does actually represent an efficient outcome given the high cost of failure. Such an approach may also enable lower procurement volumes and costs to the system, thereby contributing to the productive and allocative efficiency of arrangements. We suggest that the AEMC more explicitly consider effectiveness in its *System services objectives*.

Furthermore, in considering the pace of the ongoing energy transition and the imperative to sustain and even accelerate this rate of change to avoid dangerous global warming, we are of the view that changes that may improve the efficiency of frequency control arrangements at the cost of effectiveness are not worth the risk of widespread system failure. As such, **amid changing power system capabilities and needs, we feel that the effectiveness of frequency control arrangements should be prioritised over their 'imputed' efficiency, particularly when efficiency is defined and assessed considering only a select set of assumed future possibilities**.

With this in mind, we find it concerning that the AEMC has progressed these frequency control rule changes to a critical stage of consultation (i.e. final round of consultation prior to a draft determination) without providing stakeholders with a detailed technical assessment by AEMO and/or another independent party. It appears to us that the draft determination for a rule change establishes a preferred direction for arrangements and that the objective of further consultation might be to refine rather than potentially revisit entirely these arrangements. **The Commission is asking stakeholders to consider service definitions, and procurement, pricing and cost-allocation arrangements without an informed assessment of their feasibility and/or contribution to effective frequency control** in the NEM to feed into a draft determination. In our view, it would have been preferable for the AEMC to have made the *FFR implementation options report*, the interim advice from the *PFR Incentivisation feasibility* report and potential advice from an independent third party on frequency control in the NEM available to stakeholders before making a draft determination.

We are also of the opinion that **effectiveness incorporates arrangements that facilitate major clean energy transition over the coming decade and beyond**. Such arrangements should be robust to a wide range of possible futures - one of those possible futures is serious action to deliver net zero emissions for the electricity sector and economy wide within 30 years. In this future, the key energy transition challenge is to deliver rapid and major renewables deployment as well as any necessary additional technologies to facilitate integration, not to deploy the most efficient 'least cost' frequency control arrangements regardless of the possible impacts this may have on that deployment.

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[1] Iain Macgill, Abhijith Prakash, and Anna Bruce, "Response to the Energy Security Board's Post 2025 Market Design Consultation Paper," 2020, 18–19, http://ceem.unsw.edu.au/sites/default/files/documents/UNSW CEEM Response to P2025 Market Design Consultation Paper.pdf.

[2] Macgill, Prakash, and Bruce, n. These are discussed in pg. 22-23.

The role of regulatory and market mechanisms in energy transition

We feel that the **AEMC's objective for rule making should more clearly articulate that market-based solutions are one possible 'means' of achieving our desired 'ends', rather than an end in themselves. The key 'end' for rule changes is the design and implementation of the most effective and resilient arrangements to deliver the higher-level objectives for our electricity sector.** It is increasingly recognised that one of the most pressing of these objectives is **assured, rapid, major and sustained emission reductions.**

Frequency control has the characteristics of a public good[3]. A degree of cooperation and coordination between AEMO, NSPs and market participants is required to ensure that frequency stability is achieved. In cases where a particular frequency control service is deemed to be effective, but where the service faces barriers to efficient market operation or the potential costs of a market-based mechanism outweigh the benefits, **we see value in the AEMC and AEMO focussing on regulatory mechanisms** (e.g. grid codes, system strength/inertia frameworks**) to coordinate and ensure the provision of system services**. Regulatory mechanisms may well enable AEMO and users of the power system to better manage and tackle some key challenges in the power system and energy market whilst both are in a state of constant flux during energy transition.

The NEM experience with FCAS arrangements highlights some of the complexities when transitioning from more regulation based to more market oriented arrangements. The introduction of FCAS markets into the NEM was initially hailed as providing far more efficient frequency control, and a world leading example of co-optimised energy and frequency control markets. Assessments of this transition certainly suggested substantial cost reductions from the previous arrangements, and highly competitive service provision compared to other jurisdictions. As AEMO has highlighted, however, there has been a troubling decline in frequency control during normal operating conditions and following power system incidents in recent years. Exploration of this deterioration in frequency control performance and resilience by AEMO and independent parties (e.g. DIgSILENT[4]) has highlighted that while the increasing penetration of inverter-based resources was contributing to this decline, so too was the behaviour of market participants withdrawing, over time, previously 'free' primary frequency response through their governor settings. These outcomes highlight the broader challenges associated with improving the interfaces between regulatory mechanisms, market-based mechanisms and power system operation to deliver more effective frequency control.

The costs of 'efficiency'

We note that while quarterly FCAS costs have risen in recent years, they have generally not exceeded 2% of total NEM costs from 2015 to 2019[5]. **'Optimising' procurement, price formation and cost allocation efficiencies are integral to successful and enduring frequency control arrangements,** but we consider that **the gains of doing so may not justify sacrifices in secure and resilient power system operation.** Furthermore, **cost savings achieved through more 'efficient' FFR and PFR could be dwarfed by additional social costs if such arrangements deter or delay major renewables deployment and hence increase emissions.**

Economic analysis has a clear role to play in assessing such potential tradeoffs. However, such assessments may fail to properly account for the costs associated with low probability but highly consequential risks associated with changed arrangements. Such assessments also need to better incorporate wider system, market and social costs associated with such changes. Social costs include accounting for the wider externality costs that can arise from delaying renewables uptake due to, for

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[3] Macgill, Prakash, and Bruce, n. We discuss the consequences of this on pg. 19.

[4] DIgSILENT, "Review of Frequency Control Performance in the NEM under Normal Operating Conditions Final Report," 2017, https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/Other_Meetings/ASTAG/371100-ETR1-Version-30-20170919-AEMO-Review-of-Frequency-Control.pdf.

[5] Australian Energy Regulator, "State of the Energy Market 2020," 2020, 114, https://www.aer.gov.au/system/files/State of the energy market 2020 - Full report A3 spread.pdf.

example, complex new arrangements that adversely impact on project economics of such plants in the absence of appropriate externality pricing.

Spot markets are not a panacea

As we outlined in our submission to the ESB's Post 2025 Market Design Consultation paper, we find it problematic that the AEMC and ESB consider spot markets to be the "gold-standard" of system services procurement mechanisms[6]. There are **several challenges to achieving efficient markets for systems services**[7], including that of efficient price formation and cost-allocation. In particular, we note that **derivatives for system services may be required to provide price signals that promote efficient investment in service provision and/or capability *in the future***. We note that the Directions paper did not discuss the potential for derivative products and markets for FCAS or other system services, based on these 'gold standard' spot markets. We encourage the AEMC and ESB to more explicitly consider the role of future pricing of systems services if spot market mechanisms are suitable and preferred.

[6] Macgill, Prakash, and Bruce, "Response to the Energy Security Board's Post 2025 Market Design Consultation Paper," 20.

[7] Macgill, Prakash, and Bruce, 19.

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Fast Frequency Response Market Ancillary Service

Q1: Problem Definition and Reform Objective – FFR Rule Change

- What are stakeholders' views on the problem definition and reform objective for FFR as set out in section 4.5.3 of the directions paper?

  Considering the technical and economic analyses presented in Section 4.5 of the Directions paper, at a high level, we agree that there is a problem, and that arrangements for a contingency FFR may assist in addressing this problem. Formal arrangements for a contingency FFR service would enhance AEMO's frequency control "toolbox" and could explicitly value FFR capabilities in a NEM that is now experiencing and projected to continue to experience declining levels of operational and installed physical inertia.

  However, we feel that the case has not been made to suggest that there is a "missing market" for fast frequency response. Whilst the AEMC has provided high-level analysis that suggests that R6/L6 FCAS costs may rise if no FFR arrangements are implemented, it is unclear to us whether new markets for contingency FFR would be a more efficient solution.

  Furthermore, it is unclear to us whether the proposed FFR arrangements will be effective and why their effectiveness is not being considered as a part of the consultation process. The AEMC has stated that AEMO's *FFR implementation options report* will include a summary of current and future available FFR capacities, an indicative service definition, the feasibility of faster active power responses and performance multipliers and modelling, and analysis of interactions between a potential contingency FFR service and existing FCAS and tight-deadband primary frequency response. We feel that this consultation process is asking stakeholders to consider a contingency FFR service definition and even faster response times without a technical assessment by AEMO or another independent party. In our view, it would have been preferable for the AEMC to have made the *FFR implementation options report* available to stakeholders before making a draft determination. This contrasts with the *Mandatory primary frequency response* rule change, in which AEMO and an independent expert[8] provided technical advice that was available to stakeholders during an initial consultation phase and prior to a draft rule change determination.

  Whilst we acknowledge that AEMO's report will "provide an important input into the Commission's draft determination", stakeholders may not be able to provide an informed perspective on whether, in their view, the rule change enables "effective utilisation of FFR services".

Q2: FFR Procurement

- What are stakeholders' views on the pros and cons of establishing new FCAS market arrangements for FFR services versus revising the existing arrangements to incorporate FFR within the fast raise and fast lower services?

  Provided that the proposed FFR services are deemed to be effective by AEMO, we feel that it might be preferable to establish new FCAS market arrangements. As outlined in the Directions paper, this could minimise changes to existing FCAS in the Market Ancillary Service Specification (MASS), may lead to more transparent dispatch outcomes and enable the service definition and characteristics to be better tailored to operational requirements. Whilst the actual benefits of a contingency FFR service are unknown, we think it is likely that the advantages of new FCAS market arrangements compared to repurposing existing R6 and L6 arrangements may outweigh the additional costs of administering, monitoring, and settling the additional services and their markets.

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[8] John Undrill, "Notes on Frequency Control for the Australian Energy Market Operator," 2019.

Furthermore, as outlined in Section 4.7.2 of the Directions paper, the current FCAS registration process means that fast-responding resources can be "registered for FCAS capacity that is significantly above their actual active power response following a contingency event". At present, this outcome may be partially mitigated by AEMO imposing minimum allowable droop settings for some FFR-capable resources, such as battery energy storage systems[9]. While this approach does not allow a resource to provide as large or as rapid of a response as it is capable of, it does reduce the potential disconnect between a resource's active power response and its registered FCAS capacity. This disconnect may be problematic as contingency service procurement assumes that a certain enabled capacity (in MW) will be able to deliver a commensurate active power response (in MW) if needed. If existing FCAS arrangements are repurposed to incorporate FFR, these droop limits will presumably be lowered or removed and faster response will not only benefit from a higher enablement limit, but also presumably from the proposed pricing scalars for fast-responding R6/L6. We feel that this is likely to exacerbate the disconnect between enabled FCAS capacity and active power response, and reward participants for a capability that reflects the registration process calculation rather than their actual active power response.

- Do stakeholders agree that the existing arrangements for contingency FCAS provide an appropriate model for FFR market arrangements?

  Yes, existing arrangements for contingency FCAS are most likely an appropriate model for FFR market arrangements.

  However, as discussed above, we think that the current registration approach for fast (R6/L6) and slow (R60/L60) FCAS may be inappropriate for a contingency FFR service. Enablement of FCAS capacity should ideally reflect the active power response following a contingency event given that procurement of contingency FCAS assumes this is the case.

- What are stakeholders' views on how each of the proposed procurement arrangements for FFR would interact with the arrangements for the existing contingency services?

  As Infigen Energy[10] and AEMO[11] have suggested, the economic outcomes of introducing new market ancillary services for FFR are likely to be improved if procured volumes reflected the level of system-wide or regional operational inertia, the contingency size and the relative cost of procuring an equivalent response through R6/L6 enablement (e.g. if the last 100 MW of contingency FFR is more expensive to procure than an equivalent capacity of R6/L6, then AEMO could procure the equivalent capacity of R6/L6). In our view, it would be ideal if AEMO were able to develop quantitative relationships between these factors (similar to the charts in Appendix G in the *Inertia requirements methodology: inertia requirements & shortfalls* report[12]) and validate them through operational experience.

  A quantitative relationship between contingency FFR and R6/L6 would enable co-optimisation of service volumes. We note that the benefits of potential co-optimisation depend on the characteristics of each FCAS market and requires further analysis by AEMO and/or the AEMC. We

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[9] Australian Energy Market Operator, "Battery Energy Storage System Requirements for Contingency FCAS Registration," 2019, n. Minimum allowable droop of 1.7%, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Battery-Energy-Storage-System-requirements-for-contingency-FCAS-registration.pdf.

[10] Infigen Energy, "Operating Reserves and Fast Frequency Response Rule Change Proposal," 2020, 5, https://www.aemc.gov.au/sites/default/files/2020-03/ERC0296 Rule change request.pdf.

[11] 20 Australian Energy Market Operator, "Submission to the AEMC's Consultation Paper – System Services Rule Changes," 2020, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_aemo_-_20200813_-_erc0263_erc0290_erc0295_erc0296_erc0300_erc0306_erc0307.pdf.

[12] Australian Energy Market Operator, "Inertia Requirements Methodology: Inertia Requirements & Shortfalls," 2018, 43–45, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

are of the view that if R6/L6 and contingency FFR volumes are co-optimised, the co-optimisation should be single-sided, i.e. contingency FFR volumes could be reduced based on the availability of cheaper R6/L6 but not vice versa. Single-sided co-optimised service procurement is currently in place between R5/L5 and regulation FCAS, whereby R5/L5 procurement volumes are reduced by the enabled volume of the corresponding regulation service[13]. We are in favour of single-sided co-optimisation due to the shorter timeframe of contingency FFR - unless contingency FFR is sustained beyond 2 seconds, increasing contingency FFR volumes at the expense of contingency PFR may reduce the effectiveness of subsequent slower frequency response schemes (R60/L60, R5/L5 and regulation FCAS)[14].

Should existing FCAS arrangements be repurposed, it is unclear how AEMO might preference or prioritise faster R6 or L6 (FFR) reserves in dispatch. While price scalars described by the AEMC may remunerate and incentivise FFR capabilities, preferential dispatch of faster reserves may be necessary for secure and/or efficient operation if there are low levels of operational inertia in a particular region or the mainland. For further discussion of this point, please see our response to the second question in *Q3: FFR Pricing Arrangements*.

- Are there any aspects of the existing contingency FCAS arrangements that should be varied for procurement of FFR services?

  See response to the question above. If service co-optimisation is deemed to be beneficial, then we see value in single-sided co-optimised service procurement whereby R6/L6 could potentially substitute contingency FFR if it reduces overall system costs. We note that the benefits of potential co-optimisation depend on the characteristics of each FCAS market and requires further analysis by AEMO and/or the AEMC.

Q3: FFR Pricing Arrangements

- What are stakeholders' views on the pros and cons of maintaining the existing FCAS pricing arrangements for FFR services?

  The advantage of maintaining the existing pricing arrangements and registration process is that there will be consistency in pricing and registration across FFR, fast and slow contingency FCAS. The current pricing approach, which incorporates the service bid and any opportunity-cost incurred in the energy market[15], is suitable in our opinion as the provision of raise and lower contingency FFR requires a unit to maintain headroom or footroom, respectively.

  As discussed in our responses to *Q2: FFR Procurement*, the main disadvantage of maintaining existing arrangements is that the current registration process for fast and slow contingency FCAS may lead to the procured quantity of FCAS not reflecting the potential active power response following a contingency. To this extent, a set of new market ancillary services for contingency FFR may be preferable as a registration process that better reflects active power delivery can be implemented.

  However, if the registration approach for contingency FFR is altered to better reflect the active power response, we see a need for AEMO to consider whether the registration process for existing fast and slow services could be modified to be more consistent with this approach. For example, a

[13] Australian Energy Market Operator, "Constraint Formulation Guidelines," 2010, 17, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2016/Constraint_Formulation_Guidelines_v10_1.pdf.

[14] Australian Energy Market Operator, "Electricity Rule Change Proposal - Mandatory Primary Frequency Response," 2019, https://www.aemc.gov.au/sites/default/files/2019-08/Rule Change Proposal - Mandatory Frequency Response.pdf.

[15] Intelligent Energy Systems, "Raise Contingency FCAS - Price Control Mechanism," 2010, n. Contains example of bid and opportunity-cost FCAS pricing in the NEM, https://www.economicregulator.tas.gov.au/Documents/IES FCAS Price Final Report July 2010 (10 3252).pdf.

50 MW battery energy storage system may be able to provide 50 MW of raise contingency FFR (or 100 MW, if it were to switch from charging at 50 MW to discharging at 50 MW), but it would be limited to providing 20 MW of contingency FCAS due to a minimum allowable droop[16]. If it were economically and/or operationally preferable for it to do so, the battery energy storage system should ideally be permitted to sustain its contingency FFR response. Conversely, a switched load may be able to provide 10 MW of raise contingency FFR but may be registered for 10-20 MW of R6/L6 if its response is sustained for duration of the registration assessment period. As such, we think it would be beneficial to assess and potentially amend the existing FCAS registration process regardless of whether FFR is procured by modifying the R6/L6 service definition or through a new set of market ancillary services.

- What are stakeholders' views on the potential pros and cons of incorporating performance-based multipliers into the pricing arrangements for FFR services?

  The advantages that might be delivered by using performance-based multipliers include lower operational costs (i.e. better performing units are likely to reduce enablement quantities) and stronger price signals for investment in high-performance FCAS capabilities. However, for a given service, these advantages are heavily dependent on what metric determines the "performance" of a unit, how, if at all, "performance" is accounted for when enabling a unit for FCAS and whether "performance" is determined *ex ante* or *ex post*. In the Directions paper, the AEMC explored using the speed of the active power response as a metric for "performance".

  Given that contingency response in the NEM has a relatively wide dead-band and that a rapid arrest of frequency deviation is preferable, the use of speed as a performance metric seems suitable so long as AEMO can assess whether faster active power responses from a single unit awaiting registration and/or from multiple units across the system will adversely affect system stability or protection systems. Another metric for performance could be whether a variable or switched controller is being used to provide FFR or PFR, given that AEMO has previously expressed concerns around the limitations of switched loads participating in raise fast contingency FCAS[17].

  One consideration that was not explored by the AEMC in the Directions paper is how performance-based multipliers would be used to improve dispatch outcomes through the sourcing of FCAS capacity with desirable characteristics given current or forecasted system conditions. For example, if existing FCAS arrangements are revised to enable the procurement of FFR, it may be preferable to procure FFR-capable R6/L6 if a dispatch outcome means that the system will be operating with low levels of inertia. Similarly, if new market arrangements are introduced, AEMO could use performance-multipliers to procure the fastest available FFR should a high RoCoF be of concern[18]. If performance-based multipliers are implemented, we suggest that the AEMC and AEMO consider how they might be used to achieve appropriate and efficient dispatch outcomes in addition to strengthening investment signals.

  An international example of including performance-based multipliers into dispatch outcomes is the dispatch of regulation in the PJM Interconnection. PJM has two regulation control signals: RegA, which is a standard regulation control signal, and RegD, which is a faster control signal intended for battery energy storage systems. The components of a unit's offer are adjusted by a performance score, which reflects how well the unit responds to the ACG signal, and a benefits factor, which, for units offering RegD, translates their regulation provision into an equivalent quantity of traditional

[16] Infigen Energy, "Operating Reserves and Fast Frequency Response Rule Change Proposal," 6.

[17] Australian Energy Market Operator, "Renewable Integration Study Appendix B : Frequency Control," 2020, 33–34.

[18] While this could be an option to mitigate RoCoF, we note that this is not the primary function of the proposed contingency FFR service.

RegA provision. When there are large demand ramps, resources with a higher benefit factor are privileged[19].

With regards to when "performance" is determined, since FFR and PFR response is governed by pre-determined control characteristics (droop setting, gain, etc.) with the actual response characteristic being assessed during the registration process, we feel that *ex ante* assessment of multipliers is suitable. This is also consistent with the use of performance multipliers as proposed for the WEM.

While we agree with the AEMC's preliminary views that the benefits of performance-based multipliers would be increased if existing FCAS arrangements are revised to facilitate FFR provision, we do not see how this solution is sufficient if FFR-capable R6/L6 cannot be preferentially dispatched when system inertia is low. Performance-based multipliers may also send investment signals for faster FFR if new market ancillary services are developed for FFR, but AEMO will need to assess whether these faster responses are desirable and if the potential costs and complexity of implementation are outweighed by operational and investment benefits.

- Do stakeholders have any other comments or suggestions in relation to the pricing arrangements for FFR services?

  While not within the scope of the rule changes being considered, we see value in the Commission considering performance-adjusted remuneration (or multipliers) for regulation FCAS. In North America, FERC Order No. 755 required ISO/RTOs to consider the performance of a resource in providing regulation services. Whilst this is predominantly associated with mileage (i.e. energy provision or withdrawal in response to AGC signals), ISOs such as PJM have linked dispatch and remuneration outcomes of regulation services to their performance with respect to the AGC signal[20]. As noted by AEMO, battery energy storage systems are delivering precise and rapid regulation FCAS but are being paid the same as thermal plants that provide lower quality regulation FCAS[21].

  Regardless of whether the Commission proceeds to consider multipliers, we ask that the Commission and AEMO confirm whether *ex post* service delivery verification is being carried out by AEMO. While there are provisions for verification in the MASS, it is unclear to us whether AEMO is verifying FCAS provision. We are of the view that inadequate provision should be penalised. For example, in the UK, the payment for the Enhanced Frequency Response service (a type of FFR) can be penalised or altogether withdrawn if the performance of a resource is unsatisfactory[22].

Q4: FFR Cost Allocation

- What are stakeholders' views on the arrangements for the allocation of costs for FFR services?

  We agree with the AEMC's initial views that existing cost allocation arrangements for contingency raise and lower services provide a basis for the proposed contingency FFR market ancillary service. As outlined by the Commission, contingency FCAS benefits all market participants and the "causer" of the need for contingency FCAS "is not readily attributable to any individual generator or load".

  We do not think that it is appropriate for FFR cost allocation to be tied to their provision of physical or synthetic/virtual inertia. In principle, this approach hinders the energy transition underway in the

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[19] Adria E. Brooks and Bernard C. Lesieutre, "A Review of Frequency Regulation Markets in Three U.S. ISO/RTOs," *Electricity Journal* 32, no. 10 (2019): 106668, https://doi.org/10.1016/j.tej.2019.106668.

[20] Brooks and Lesieutre.

[21] Australian Energy Market Operator, "Initial Operation of the Hornsdale Power Reserve Battery Energy Storage System," 2018, 6.

[22] Daniel Fernández-Muñoz et al., "Fast Frequency Control Ancillary Services: An International Review," *Renewable and Sustainable Energy Reviews* 120, no. December 2019 (2020), https://doi.org/10.1016/j.rser.2019.109662.

NEM by treating inertia as a by-product of energy generation (we elaborate on this idea in our response to *Q6: Valuation of Inertial Response*).

This approach may also result in perverse outcomes. Unlike the proposed contingency FFR, virtual or synthetic inertia responds to RoCoF and may begin to reduce its active power response as the system frequency is closer to being arrested[23]. As such, the provision of virtual/synthetic inertia alone may not necessarily reduce the need for contingency FFR as the function of virtual/synthetic inertia is primarily to mitigate RoCoF rather than provide a sustained active power response. However, it is important to note that much like inertial response and PFR, the response from virtual/synthetic inertia can be sustained through control schemes that enable sustained FFR/PFR provision.

Furthermore, this approach essentially imposes a "do-no-harm"-style obligation on non-synchronous generation with regards to inertia/frequency. In our view, a "do-no-harm" approach is not a coordinated nor an efficient strategy for procuring system services (we note that this was the justification for the "Efficient management of system strength on the power system" rule change proposed by TransGrid[24]).

We feel that the largest "causers" of costs are contingency size and unit reliability[25]. If the Commission wishes to better allocate the costs of contingency FCAS, these two factors could be considered first.

- Would it be appropriate for the cost of FFR services to be allocated in a similar way to the existing arrangements for the allocation of contingency FCAS costs?

  Please see response to question above. We believe that these arrangements are likely the most appropriate at this point in time.

Q5: Issues for Consideration – FFR

- Are stakeholders aware of any additional issues that the Commission should take into account in developing market ancillary service arrangements for FFR?

  An additional issue that needs to be explored is how best to coordinate new arrangements for contingency FFR with existing regulatory mechanisms that enable FFR procurement. In particular, the inertia framework places an obligation on TNSPs to procure inertia services to meet an inertia requirement or procure inertia support activities to reduce the inertia requirement for an inertia sub-network (region)[26]. As noted by the Commission, AEMO's recent shortfall declaration for South Australia involves resolving the shortfall through the procurement of FFR as an inertia support activity[27].

  We suggest that the AEMC explore how inertia support activities could better be coordinated with new market arrangements for contingency FFR.

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[23] Rick Wallace Kenyon et al., "Stability and Control of Power Systems with High Penetrations of Inverter-Based Resources: An Accessible Review of Current Knowledge and Open Questions," *Solar Energy* 210, no. April (2020): 149–68, https://doi.org/10.1016/j.solener.2020.05.053.

[24] TransGrid, "National Electricity Rules Change Proposal: Efficient Management of System Strength on the Power System," 2020, https://www.aemc.gov.au/sites/default/files/documents/erc0300_rule_change_request_pending.pdf.

[25] Jenny Riesz, Joel Gilmore, and Iain MacGill, "Frequency Control Ancillary Service Market Design: Insights from the Australian National Electricity Market," *Electricity Journal* 28, no. 3 (April 2015): 86–99, https://doi.org/10.1016/j.tej.2015.03.006.

[26] Australian Energy Market Operator, "Inertia Requirements Methodology: Inertia Requirements & Shortfalls."

[27] Australian Energy Market Operator, "Notice of South Australia Inertia Requirements and Shortfall Important," 2020, https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2020/2020-notice-of-south-australia-inertia-requirements-and-shortfall.pdf?la=en&hash=673E32C8547A8170C9F4FA34323F3A8F#:~:text=In current a.

Q6: Valuation of Inertial Response

- What are stakeholders' views on the valuation of inertial response as part of the contingency services, including the proposed new FFR contingency services?

  We think that it is inappropriate to value inertial response as a part of contingency services, including the proposed FFR contingency services. While the functions of contingency services and inertial response have some overlap, these system services are by no means interchangeable.

  Unlike inertial response, contingency services are sustained and entail material opportunity-costs related to energy generation. Inertial response is delivered because the rotors of synchronous machines can store electrical energy in the form of kinetic energy. In contrast, raise contingency services provide a "store" of energy (headroom) by foregoing energy production. The difference between these "stores" of energy is evident from the units of each - as noted by AEMO, inertia is measured in MWs whilst FFR and contingency services are measured in MW[28]. Furthermore, the "store" of energy in a synchronous rotor is never completely exhausted and is, and indeed must be, replenished as the system frequency recovers to the nominal value. In contrast, frequency control services may exhaust some or all their "store" (headroom) in response to a frequency deviation. As such, while there is an opportunity-cost directly related to energy generation associated with the provision of contingency services., inertia is not provided at the expense of a unit's energy generation.

  We also note that inertial response, unlike contingency or RoCoF-responsive FFR such as virtual inertia, can mitigate the *initial* (which is often the maximum) rate of change of frequency (RoCoF) following a loss of load or generation[29]. A more holistic valuation of inertia would also consider its value in RoCoF mitigation. However, in practice, this too may prove to be problematic for two reasons. First and foremost, inverter-based resources can implement control schemes with virtual or synthetic inertia that are able to respond to RoCoF. While these schemes are unable to mitigate *initial* RoCoF, they would need to also be considered as a RoCoF mitigation tool and valued to better reflect the value of physical inertia in a transitioning power system. Secondly, more sophisticated pricing and cost-allocation arrangements for physical inertia would need to consider that the beneficiaries of inertia provision may also be those that provide it. Gas turbines can suffer from lean blowout or a compressor surge trip whilst experiencing high RoCoF[30]. In a modelling study commissioned by EirGrid, thermal synchronous generators begun to experience pole slipping at a RoCoF of 1.5-2 Hz/s[31]. While the phase-locked loops of inverter-based resources might contribute to instability or a unit trip during high RoCoF events, there is no inherent limitation associated with the unit or control system, the latter of which can be retuned or upgraded[32].

  We feel that it is likely that a low or zero carbon NEM may have little to no operational physical inertia available. As such, the power system will need to have the capabilities to operate in these conditions. Whilst power system operators, market designers and researchers are still learning about and working on advanced inverter control capabilities such as virtual/synthetic inertia, we feel that market and regulatory arrangements should be robust enough to handle a variety of situations, including a rapid transition to net zero emissions. While we would encourage AEMO and

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[28] Australian Energy Market Operator, "Submission to the AEMC's Consultation Paper – System Services Rule Changes," 18.

[29] Kenyon et al., "Stability and Control of Power Systems with High Penetrations of Inverter-Based Resources: An Accessible Review of Current Knowledge and Open Questions."

[30] Nicholas Miller et al., "Advisory on Equipment Limits Associated with High RoCoF," 2017, 17–22, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/20170904-GE-RoCoF-Advisory.

[31] DGA Consulting, "International Review of Frequency Control Adaptation," 2016, 29–31, https://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/FPSS---International-Review-of-Frequency-Control.pdf.

[32] Miller et al., "Advisory on Equipment Limits Associated with High RoCoF," 39–47.

the AEMC to consider how best to mitigate RoCoF concerns without relying on carbon-intensive generation and how FFR might be used to reduce physical inertia requirements, we acknowledge that in the short to medium-term, physical inertia may need to be procured to ensure the power system can be securely operated.

Physical inertia can be provided by synchronous condensers, which include synchronous generation fitted with synchronous condensing clutches, only at the expense of a small parasitic active power load[33]. In the UK, National Grid ESO has recently completed a round of tendering for system stability services (voltage control, fault level and inertia) with zero MW output[34]. Given that synchronous condenser technology is proven and that the provision of inertia does not come at the expense of providing other active power services, we are of the view that physical inertia provision should not be linked to the generation or consumption of active power and therefore not be intertwined with energy market outcomes. As such, we are of the view that is preferable to value *physical* inertia provision without its value reflecting the cost of services that are intrinsically linked to the generation or consumption of active power.

Our preference for the procurement of physical inertia is for a transparent and competitive structured procurement mechanism for the provision of inertia that is not tied to the generation or consumption of energy. As we discussed in our response to the ESB's Post 2025 Market Design Consultation paper, we believe that a spot-market mechanism for inertia may be problematic[35]. Both in the short term and longer term, we feel that distortion to the energy market may be minimised by preferentially procuring FFR services to reduce operational inertia requirements for regions in the NEM (as AEMO has suggested in declaring an inertia shortfall for South Australia[36]).

- What are stakeholders' views on the current governance arrangements for contingency services; where the detailed service specification is determined by AEMO and documented in the MASS? (Is it appropriate for the NER to provide further guidance on how inertial response should be considered in the MASS?)

  The references to inertial response in the MASS are related to excluding inertial response from determining the quantity of contingency service provided by a resource. As we have discussed above, we feel that inertial response and contingency services are different services. The MASS reflects this view and we therefore do not think that the NER needs to provide further guidance on how inertial response should be considered in the MASS.

Q7: Price Responsive Demand for Contingency Services

- What are stakeholders' views on the potential pros and cons associated with the implementation of a "demand curve" approach to procurement of FCAS?

  We see two primary advantages in implementing a system demand curve. As the AEMC has discussed in the Directions paper, a system demand curve could enable AEMO to procure FCAS beyond minimum volumes that, in the case of contingency services, only reflect credible contingencies. Additional contingency reserves could improve system frequency control if a non-credible contingency were to occur and a demand curve would enable their procurement at reasonable cost. Furthermore, we think that system demand curves may assist in strengthening FCAS price formation. Market equilibrium prices for FCAS are likely to be higher with a price-

[33] Huajie Gu et al., "Review of System Strength and Inertia Requirements for the National Electricity Market of Australia," *CSEE Journal of Power and Energy Systems* 5, no. 3 (2019): 295–306, https://doi.org/10.17775/cseejpes.2019.00230.

[34] National Grid ESO, "Stability Phase One Tender Interactive Guidance Document," 2019, https://www.nationalgrideso.com/document/157176/download.

[35] Macgill, Prakash, and Bruce, "Response to the Energy Security Board's Post 2025 Market Design Consultation Paper," 26–27.

[36] Australian Energy Market Operator, "Notice of South Australia Inertia Requirements and Shortfall Important."

responsive demand curve than with a vertical demand curve when supply in the market is abundant but not saturated. Whilst this may lead to higher costs in the short-term, higher FCAS prices that better reflect the value of the service to the system may improve the incentives for provision and investment in FCAS capability, particularly for high capital, low operating cost inverter-based resources, and reduce long-term costs as conventional generators with low marginal opportunity-costs retire. We acknowledge that in recent years, FCAS markets have seen a growing number and diversity of providers in recent years as well as an increase in contingency[37] and regulation FCAS[38] procurement volumes. However, our view is that in the long term, system demand curves may provide operational and investment incentives for frequency response capabilities from inverter-based resources and provision of frequency response from these services will be inevitable, if not crucial.

The main disadvantages of a system demand curve are that it may increase short-term FCAS costs and introduce further complexity in the market. Beyond these, we also anticipate that determining a suitable demand curve will be challenging. Ideally, the system demand curve are "dynamic" and express the system's preferences for FCAS based on power system conditions. This means that the minimum procurement volume is dynamic (as it currently the case) and that the slope of the demand curve should vary as measures such as Forecast Uncertainty Measure and Loss of Load Probability vary too. Should interchangeable or interdependent FCAS be procured based on different power system metrics (e.g. contingency FFR procurement adjusted based on operational inertia), we also see a need for system demand curves between services to interact with one another. For example, a system "weak-link" could arise if additional faster reserve were procured but the initial response was not sustained by subsequent FCAS.

Whether system demand curves can deliver material resilience benefits is dependent on the role of regulatory mechanisms in the NEM. If access or participation conditions require a broad majority of the generation fleet to provide measurable frequency response (e.g. mandatory PFR), then the additional resilience benefits of system demand curves may be low.

- What are stakeholders' views on the priority of such a change to the market frameworks?

  We do not see system demand curves as an immediate priority, given that their utility is likely to become clearer after the AEMC has delivered its determination on the multiple system services rule change projects underway. In particular, if grid codes continue to mandate some level of minimum or consistent frequency response[39] (e.g. mandatory PFR), there may be a weaker justification for implementing complex demand curves.

- If such an approach was to be implemented, what are stakeholders' views on the appropriate governance arrangements, including the potential oversight role for the AER?

  We agree with the AEMC's initial views that AEMO would be better placed to determine and apply price-responsive demand curves.

  While we agree that there is a potential oversight role for the AER, it is unclear to us how price-responsive demand curves could be assessed. Whilst costs (or additional costs) are easily quantified, the benefits we discussed above are not.

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[37] Australian Energy Market Operator, "Review of NEM Load Relief," 2019, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/2019/Update-on-Contingency-FCAS-Nov-2019.pdf.

[38] Australian Energy Market Operator, "Electricity Rule Change Proposal - Mandatory Primary Frequency Response," 36–37.

[39] We note that in our view, generator technical performance standards do not necessarily deliver a minimum or consistent frequency response, as the NER mandate capability (rather than actual response) and as capability/response can be negotiated.

Q8: Interaction Between Mandatory PFR & FFR Arrangements

- What are stakeholders' views in relation to the potential interactions between new FFR arrangements and the Mandatory PFR arrangement?

  We feel that it is important to highlight the control interaction between mandatory PFR and contingency FFR. If effective frequency control can be established within the normal operating frequency band through tight-deadband PFR (mandatory or otherwise) and regulation FCAS, contingency services can be supported by these 'first responders' and there is a reduced likelihood of activating a contingency response in situations aside from the most severe (as preliminary results from the implementation of mandatory PFR suggest[40]). The latter is particularly important in the case of the rapid active power response of FFR and switched loads, which provide a "one-shot" response and do not not provide closed-loop (feedback) control[41]. As such, we consider it necessary to maintain tight-deadband PFR in the NEM to support the effective and efficient use of contingency services.

  However, as recognised by the AEMC, we are concerned that headroom/footroom reserved for contingency services (FFR or otherwise) may be utilised as a part of a tight-deadband PFR response. Widespread tight-deadband PFR provision is likely to minimise the response required from an individual resource[42], but to ensure that headroom/footroom is conserved by a resource that is providing both mandatory PFR and one or more contingency services, we support explicitly procuring and remunerating headroom for each service and the use of a variable droop approach (as implemented by National Grid ESO in their dynamic containment service) where possible.

Q9: Implementation and Staging for FFR

- What are stakeholders' views in relation to the process for the implementation of FFR arrangements in the NEM?

  As stated previously, we are disappointed that the AEMC has not provided more detailed technical advice from AEMO and/or an independent party as a part of this consultation process. This hinders providing an informed perspective on the effectiveness of the changes proposed in this consultation process.

  In our opinion, if the proposed FFR arrangements are deemed feasible and effective by AEMO then interim or transitional arrangements can be implemented to allow AEMO to gain operational experience with FFR in the NEM (briefly discussed in response to the next question). Once experience from this process can be digested, we feel it is then appropriate for a potential market design for contingency FFR to be refined and implemented. Existing contingency FCAS market arrangements are likely to be an appropriate and proven template for a contingency FFR service. It might be preferable to consider more sophisticated pricing and cost-allocation schemes after the AEMC has completed its series of system services rule changes and if their potential benefits might outweigh the additional implementation costs, monitoring and settlement costs and market complexity.

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[40] Australian Energy Market Operator, "Implementation of the National Electricity Amendment (Mandatory Primary Frequency Response) Rule 2020: Status as at 20 Jan 2021," 2021, 19, https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2020/pfr-implementation-report-v11-20-jan-21.pdf?la=en.

[41] Australian Energy Market Operator, "Renewable Integration Study Appendix B : Frequency Control," 33–34.

[42] Australian Energy Market Operator, "Electricity Rule Change Proposal - Mandatory Primary Frequency Response," 59.

- What are stakeholders' views on the potential need for interim or transitional arrangements as part of the transition to spot market arrangements for FFR?

  We support AEMO's suggestion of initially taking a contracting approach. This would provide AEMO with flexibility in how the FFR services are used, how their technical issues might be managed and would provide valuable operational experience that could eventually feed into the design process of a 5-minute spot market.

Primary Frequency Response Incentive Arrangements

Q10: The Role of Mandatory PFR

- Do stakeholders agree that a mandatory PFR arrangement provides a valuable safety net to help protect the power system from significant non-credible contingency events?

  As discussed by the AEMC, there are several benefits to *tight-deadband PFR* during system intact operation. Tight-deadband PFR complements and assists the slow and centralised secondary frequency control delivered by regulation FCAS[43], thereby improving frequency control during normal operation. As outlined in the mandatory PFR implementation update released by AEMO in January 2021, better control of system frequency within the NOFB since the implementation of mandatory PFR has led to fewer departures of system frequency beyond the NOFB, thereby reducing the utilisation of emergency contingency reserves[44]. Tight-deadband PFR can also complement the response of contingency services to both credible and non-credible events. In addition to these immediate operational benefits, AEMO has increased certainty of how resources respond to frequency and is therefore able to better model the power system.

  The benefits of *widespread PFR provision* are more material as the power system deviates from normal operation. During normal operation, widespread provision reduces the contribution required from an individual resource, as the burden of response is spread across all PFR providers. However, in the case of significant and complex non-credible contingency events, widespread PFR provision may be critical to avoiding significant load or generation shedding and cascading failures. In particular, the long and 'stringy' network topology of the NEM means that its regions are more susceptible to islanding than other interconnected systems.

  We highlight the need for system resilience using the example of the double separation that occurred on the 25th of August 2018. Following the double separation event on the 25th of August 2018, contingency reserves in the NSW-VIC and QLD islands were insufficient or inappropriate to respond to frequency in the NSW-VIC and QLD islands. There was insufficient raise FCAS whilst NSW-VIC was under-frequency and there was no lower FCAS enabled to respond to over-frequency in QLD[45]. While AEMO is considering regional requirements for FCAS[46], widespread PFR provision may have provided valuable assistance in this situation.

  Widespread PFR provision may also be useful to help maintain frequency in the normal operating frequency band in situations where centralised secondary control does not respond appropriately to local frequency conditions. Following the double separation event, AEMO's AGC instructed raise regulation FCAS providers in QLD and SA to respond to under-frequency in the AGC frequency reference despite local over-frequency. Such incorrect control action can occur until AEMO is able

[43] Australian Energy Market Operator, 6; Jan Machowski et al., *Power System Dynamics: Stability and Control*, 3rd ed. (John Wiley & Sons, Ltd, 2020), 360–64.

[44] Australian Energy Market Operator, "Implementation of the National Electricity Amendment (Mandatory Primary Frequency Response) Rule 2020: Status as at 20 Jan 2021," 19.

[45] Australian Energy Market Operator, "Final Report – Queensland and South Australia System Separation on 25 August 2018," 2019, 24, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/Qld---SA-Separation-25-August-2018-Incident-Report.pdf.

[46] Australian Energy Market Operator, "Renewable Integration Study : Stage 1 Report," 2020, 41, https://www.aemo.com.au/-/media/files/major-publications/ris/2020/renewable-integration-study-stage-1.pdf.

to manually reconfigure the AGC to treat each island as a control area - a process which can take up to 15 minutes[47].

As such, we see *widespread PFR provision* as a valuable safety net in the case of significant and/or complex non-credible contingencies, and *tight-deadband PFR* as integral to effective frequency control within the normal operating frequency band and complementary to existing contingency services. In our opinion, mandatory PFR is necessary to ensure that PFR provision is widespread, and we see value in maintaining mandatory PFR for the sake of resilience whilst the NEM is undergoing energy transition.

We also note that a mandatory requirement ensures that newly-connecting inverter-based resources will have practical frequency response capabilities and participate in power system frequency control. This will provide both market participants and AEMO with operational experience in controlling power system frequency with inverter-based resources. This experience will be valuable in ensuring that the power system can be securely operated as thermal generation retires and more inverter-based resources connect to the NEM.

- Do stakeholders agree that the narrow, moderate and wide settings for a mandatory PFR response band adequately represent the broad policy options for the frequency response band for Mandatory PFR?

  At a high level, we agree that the narrow, moderate and wide settings for a mandatory PFR deadband represent the policy options for enduring mandatory PFR arrangements.

  However, we feel that the AEMC has not discussed a narrow deadband setting aside from the current primary frequency control band (±15 mHz). While this deadband is consistent with PFR requirements for some control areas such as continental Europe[48], U.S interconnections require newly-connecting generation to operate with maximum deadbands of ±36 mHz[49] (equivalent to ±30 mHz for a 50 Hz system such as the NEM) and, prior to the introduction of FCAS markets, mandatory PFR was required in the NEM around a deadband of ±50 mHz[50]. We are of the view that narrow deadband settings could be better explored to consider a range of deadband settings between ±0 mHz and ±150 mHz. This will require input from AEMO and further work to understand whether there is a material difference in performance and/or costs in this tight-deadband range.

  While further analysis and work is required to understand its potential effectiveness, we question the value of a moderate deadband setting at the limits of the NOFB given that generation would only be obliged to provide PFR less than 1% of the time[51]. However, this setting may be acceptable if effective tight-deadband PFR can be procured through other arrangements such as a new market ancillary service.

  We do not think that the wide deadband (±500 mHz) setting should be implemented for the reasons outlined by AEMO in their mandatory PFR rule change proposal[52].

[47] Australian Energy Market Operator, "Final Report – Queensland and South Australia System Separation on 25 August 2018," 6.

[48] European Network of Transmission System Operators for Electricity (ENTSO-E), "Network Code on Load-Frequency Control and Reserves" (2013), https://eepublicdownloads.entsoe.eu/clean-documents/pre2015/resources/LCFR/130628-NC_LFCR-Issue1.pdf.

[49] Federal Energy Regulatory Commission (FERC), "Order No. 842: Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response," 2018, https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/E-2_Order on Primary Frequency Response.pdf.

[50] Australian Energy Market Operator, "Electricity Rule Change Proposal - Mandatory Primary Frequency Response," 5.

[51] Australian Energy Market Operator, 48.

[52] Australian Energy Market Operator, 47–48.

Q11: Problem Definition and Reform Objective – PFR Incentive Arrangements Rule Change

- What are stakeholders' views on the problem definition and reform objectives for enduring PFR arrangements set out in section 5.4?

  We agree with the segments of the problem statement that highlight the operational significance of PFR and that stress the need for arrangements past the sunset date of existing mandatory PFR arrangements. However, we disagree with the statement below to some extent:

  > *The mandatory PFR arrangement on its own is not a complete PFR solution since it does not value the provision of frequency response provided outside of that enabled through the market ancillary service arrangements for regulation and contingency reserves. The Commission considers that this under-valuation of PFR does not support efficient allocation of resources in the NEM and weakens the signals for efficient investment in power system plant to meet future power system needs.*

  We feel that the mandatory PFR arrangement on its own is not a complete PFR solution, but rather because it does not value or compensate resources for providing headroom or footroom that enable PFR to be effective. While preliminary analysis suggests that mandatory PFR has been effective without requiring the provision of headroom[53], we caution the AEMC to not assume that this headroom/footroom will always be available in the future.

  We agree that current arrangements do not lead to the "efficient allocation of resources in the NEM". An appropriate incentive scheme or market-based mechanisms may enable headroom and/or footroom to be provided at lowest cost by resources that are perhaps better-placed to provide tight-deadband PFR. However, selective procurement and efficiency may come at the cost of additional power system resilience. The costs of widespread PFR provision may well be justified if it is effective and makes each sub-network and the NEM more resilient to variability and uncertainty.

  We are of the view that incentives and/or market-based arrangements do not offer significant advantages in promoting *efficient investment in power system plant to meet future power system needs* with regards to PFR provision. The technology and control schemes to provide PFR are well-established for conventional plant and battery energy storage systems, and will become well-established in the NEM for variable renewable energy once PFR control system software changes are confirmed with the OEMs, trialled and rolled out[54]. Furthermore, the capability to provide frequency response outside the NOFB to a standard that is acceptable for FCAS provision is included in the frequency control automatic access standard for connecting generation[55]. The additional market costs and complexity of market-based arrangements may not be necessary to provide an incentive for capability…:

  1. …since fast and slow contingency FCAS markets already provide this incentive and;
  2. if PFR capabilities are already widespread across the generation fleet and if they are required (or, in the case of mandatory PFR, if provision of PFR is required) as a condition of access or participation in the energy market.

  If any incentive is required, it is the incentive for participation/provision, not for the capability. Furthermore, incentivising advanced and innovative PFR capabilities ("to meet future power system

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[53] Australian Energy Market Operator, "Implementation of the National Electricity Amendment (Mandatory Primary Frequency Response) Rule 2020: Status as at 20 Jan 2021," 18.

[54] Australian Energy Market Operator, 7.

[55] NER S5.2.5.11 – Frequency control

needs") may not be necessary through a procurement scheme for tight-deadband PFR service as incentives or market-based mechanisms are already being considered for these capabilities through distinct service arrangements (e.g. contingency FFR and other FFR services).

Q12: Economic Analysis of Mandatory PFR

- What are stakeholders' views of the example curves for costs and benefits of Mandatory PFR with respect to the frequency response band settings, set out in figure 5.4?

  We agree with some of the concepts in these curves. The marginal security benefit of a tighter deadband setting closer to 50 Hz is likely to be smaller than that of tightening the deadband setting further away from 50 Hz. We also agree that there are several potential cost curves. We look forward to seeing data and analysis from AEMO and market participants regarding the costs of implementing and providing mandatory PFR.

  However, we feel that there are two issues with this framework as presented in the Directions paper:

  1. The aggregate security benefits curve presented in the Directions paper implies that the maximum marginal security benefit (i.e. maximum slope of the curve) occurs somewhere between the ± 0.5 Hz and ± 1Hz deadband settings. While these curves are conceptual, we think that this depiction risks misleading stakeholders as a deadband setting at the edges of the NOFB means that generation would only be obliged to provide PFR less than 1% of the time (according to AEMO[56]). We think it is likely that security benefits may be low until the deadband approaches or is tighter than the NOFB.

  2. The security curve drawn by the AEMC does not account for PFR from contingency FCAS at or beyond the NOFB. If the curve instead showed the marginal security benefit offered by mandatory PFR as a proportion of "total system security", the marginal benefits would be higher within the NOFB and much lower at and beyond the NOFB as contingency FCAS will offer a response at these frequency values.

- Do stakeholders agree that the frequency response band setting is a key variable for the determination of enduring PFR arrangements that meet the power system needs and are economically efficient over the long term?

  The frequency response deadband is a key variable in designing effective and efficient enduring PFR arrangements so long as these arrangements can also guarantee or procure headroom/footroom. Without appropriate arrangements for headroom/footroom, costs and benefits under different settings will be distorted or distributed unevenly amongst providers.

- What are stakeholders' views on the effectiveness of the exemption framework under the Mandatory PFR arrangement?

  While we have no direct experience with the exemption framework, the principles for exemption seem fair. Given the low number of exemption applications as a proportion of the number of affected generators in each tranche and that no exemptions have been granted to date[57], we feel that it is unlikely that a significant proportion of newly-connecting generation will be exempted from provision and therefore reduce the resilience and effectiveness of mandatory PFR.

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[56] Australian Energy Market Operator, "Electricity Rule Change Proposal - Mandatory Primary Frequency Response," 48.

[57] Australian Energy Market Operator, "Implementation of the National Electricity Amendment (Mandatory Primary Frequency Response) Rule 2020: Status as at 20 Jan 2021," 4–5.

- What are stakeholders' views on the role that the allowance for variable droop settings plays in relation to the cost impacts of Mandatory PFR?

  As outlined in our responses to questions in the *Fast Frequency Response Market Ancillary Service* section, we support considering variable droop settings, particularly when a plant is providing mandatory PFR and one or more contingency services. Specifically, in the context of mandatory PFR provision, variable droop may mitigate the cost of PFR provision if a tight deadband setting is required. We support the AEMC in seeking advice from AEMO and an independent third party on the feasibility, effectiveness and costs of a variable droop arrangement for mandatory PFR and contingency PFR/FFR services.

- Based on the initial roll out of the Mandatory PFR arrangement to generators over 200MW, what are stakeholders' views on how the cost impacts of Mandatory PFR are impacted by the proportion of the fleet that is responsive to frequency variations?

  We are unable to provide an informed comment on this but look forward to seeing responses from market participants. We anticipate that cost impacts will be reduced as a greater proportion of the fleet becomes responsive.

- What other considerations are there in relation to developing effective and efficient arrangements for PFR in the NEM?

  As mentioned earlier in this submission, we caution against the assumption that units providing mandatory PFR will continue to retain headroom/footroom into the future. The marked improvement in NOFB frequency control visible in the preliminary results of mandatory PFR implementation is likely due to conventional plant retaining headroom/footroom[58]. As thermal generation retires and the generation mix changes during energy transition, it is important that remaining and new plant are incentivised, remunerated or required to provide headroom/footroom. A similar assumption was presumably made at the inception of the NEM with regards to the voluntary provision of tight-deadband PFR. As has become clear now, the provision of tight-deadband PFR was withdrawn by many generators due to the lack of regulatory requirements, remuneration or incentives and perceived disincentives[59].

Q13: Advice for Enduring PFR Arrangements

- What are stakeholders' views of the Commission's proposed approach to obtaining advice to inform its determination of enduring arrangements for PFR in the NEM?

  While we are disappointed that the AEMC has not provided technical advice from AEMO and/or an independent party prior to or during this consultation process, we support the AEMC in obtaining further advice to inform its determination. In particular, we consider the preliminary questions that the AEMC is likely to seek independent advice on (Section 5.2.2) to be significant in determining an enduring PFR pathway for the NEM. Any informed response to these questions is likely to draw upon data and experience from mandatory PFR, contextualised data and experience from international power systems and energy markets and technical expertise and power system modelling, where appropriate. Our key concern is how the AEMC will incorporate such inputs into the draft determination in the absence of guidance from stakeholders about the implications of this advice for rule making.

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[58] Australian Energy Market Operator, "Implementation of the National Electricity Amendment (Mandatory Primary Frequency Response) Rule 2020: Status as at 20 Jan 2021."

[59] Iain Macgill, Max Zekulich, and Anna Bruce, "Electricity Market Norms vs Power System Norms : The Example of Primary Frequency Response in the Australian National Electricity Market," 2020; DIgSILENT, "Review of Frequency Control Performance in the NEM under Normal Operating Conditions Final Report."

Q14: Procurement Arrangements for Narrow Band PFR Services

- What are stakeholders' views on three options identified for further consideration?

  a. Existing market ancillary service arrangements

  We do not consider this option to be appropriate. As outlined by the AEMC, it is problematic for resources to provide tight-deadband PFR and regulation FCAS regulation services at the same time, particularly because the effectiveness of regulation FCAS is dependent on the rapid and effective provision of tight-deadband PFR.

  In our view, narrowing of the response band to enable generators providing contingency FCAS to provide tight-deadband PFR is also not preferable. The provision of tight-deadband PFR by generators also providing contingency FCAS may reduce the available emergency energy reserve. This additional contingency reserve may be critical in ensuring that the power system can remain secure following a credible or non-credible contingency. Furthermore, switched contingency FCAS may not be able to provide tight-deadband PFR. It is unclear how this option would accommodate for switched response.

  However, we are of the view that it may be appropriate for providers of contingency FCAS to also provide tight-deadband PFR so long as headroom/footroom is procured for each service in an independent manner. This would ensure that headroom/footroom is reserved for tight-deadband PFR and that the full enabled response can be delivered in response to system frequency leaving the NOFB.

  b. New market ancillary service arrangements

  As discussed in the Directions paper and in our responses in the *Fast Frequency Response Market Ancillary Service* section, new market ancillary service arrangements offer several operational and economic benefits. AEMO would be able to specify the requirements for the service, procure a certain quantity of the service based on power system conditions and tight-deadband PFR would be provided by resources that are able to offer headroom/footroom into the market at the lowest cost.

  However, it is unclear to us if the benefits of a market for tight-deadband PFR outweigh the costs of a potential market (some of our thoughts on this matter are outlined in our response to *Q11: Problem Definition and Reform Objective – PFR Incentive Arrangements Rule Change*). In particular, the costs of mandatory PFR provision may be low if a large proportion of the generation fleet is responsive and may be further lowered by altering the response deadband and implementing variable droop settings. If the costs of providing mandatory PFR for an individual resource are low, then we question whether implementing a new market ancillary service would lower system-wide costs. Furthermore, if mandatory PFR is wholly replaced by a new market ancillary service, the resilience benefits of widespread PFR provision might be lost. Again, the Queensland and the South Australian separation events in August 2018 highlighted some of the risks associated with market provision from potentially a relatively small number of providers who may prove unable, due to wider power system events such region separation, or local generator/load issues, to deliver what they have committed to provide.

  Nevertheless, as with structured procurement and regulated pricing, a market ancillary service would be able to value the provision of headroom/footroom and compensate providers for their opportunity-cost. Given that the AEMC is leaning towards a market-based arrangement, we would support a new market ancillary service provided that mandatory PFR is retained and the option of maintaining mandatory PFR at tighter deadbands is better explored. If the costs of provision within a tight-deadband are low and can be further lowered through variable droop settings and/or minor deadband adjustments, we anticipate that it would be preferable to maintain a tight deadband to ensure that power system frequency control is as effective and resilient as it can be during energy transition. This set of arrangements would effectively introduce a market for *firm headroom/footroom*, rather than a market for both the capability and headroom/footroom.

We also question whether a primary regulating service could be co-optimised with a secondary regulating service, given that the latter is dependent on the former.

c. New incentive-based arrangements for voluntary provision

We do not consider this option to be appropriate, especially given the failure of regulation FCAS Causer Pays to incentivise PFR provision within the NOFB in the NEM. While the intention of Causer Pays was to disincentivise active power deviations that were harmful to frequency control, several generators disabled governor response in the NOFB in the belief that dispatch adherence alone will minimize Causer Pays liabilities[60]. While in theory the proposed incentive schemes (double-sided Causer Pays and frequency response deviation pricing) may better incentivise tight-deadband PFR than existing Causer Pays arrangements, we are unsure how these schemes will address issues in calculating contribution factors that unfairly penalise variable renewable energy (discussed in our response to *Q16: Allocation of Costs for Narrow Band PFR*).

The success of incentive schemes is highly dependent on their pricing outcomes, and thus their design. Price outcomes from incentive schemes may not be able to reflect the opportunity-cost of PFR provision. This may affect whether plant provide tight-deadband PFR. Without guaranteed tight-deadband PFR, regulation FCAS alone may be unable to effectively control frequency within the NOFB. As such, voluntary provision may result in conditions in the NEM that justified the implementation of mandatory PFR in the first place. Even if the incentives were sufficient, AEMO would have no direct control over the characteristics and volume of tight-deadband PFR.

- Are there any other options that would be preferable?

  Please see part (b) of the previous question.

Q15: PFR Pricing Arrangements

- What are stakeholders' views on the arrangements for the pricing of PFR as described in section 5.6.2?

  In our view, the appropriate pricing outcome is entirely dependent on the chosen procurement method. If mandatory PFR is retained as is and the AEMC does not pursue market-based arrangements for tight-deadband PFR response or headroom/footroom, then structured procurement may be required to procure headroom/footroom. Alternatively, regulated pricing could achieve a similar outcome but would need to incorporate resource mileage to value headroom/footroom. It may also be challenging for the AER to determine fair and cost-reflective prices.

  Pricing through dispatch enables a particular resource's offer to be considered alongside the opportunity-costs of provision of other FCAS and/or energy and total system-wide costs. This pricing method is suitable if a market-based arrangement is implemented.

[60] DIgSILENT, "Review of Frequency Control Performance in the NEM under Normal Operating Conditions Final Report."

We assume that the pricing of tight-deadband PFR provision would be determined by the so-called "price function" for double-sided Causer Pays or frequency response deviation pricing. As no details have been included as to what variables the price function might include or how the price function might work, we cannot comment on this option. However, we outline potential issues with these cost-allocation methods in our response to *Q16: Allocation of Costs for Narrow Band PFR.*

Q16: Allocation of Costs for Narrow Band PFR

- What are stakeholder's views on the allocation of costs for narrow band PFR services as described in section 5.6.3?

The AEMC has proposed to incorporate the costs of tight-deadband PFR within the existing cost allocation for regulation FCAS as both services would be responsible for controlling system frequency during normal operation. As regulation FCAS Causer Pays essentially assigns costs to resources that deviate from dispatch instructions in a direction opposite to action of regulation FCAS (except for when the Frequency Indicator is in the opposite direction to a system frequency deviation[61]), it seems appropriate to bundle cost-allocation for tight-deadband PFR and regulation FCAS together. As highlighted by the AEMC, this may also reduce the complexity of cost-allocation arrangements in the NEM (although the Causer Pays methodology could eventually be further refined or replaced by frequency response deviation pricing).

However, we cannot support this approach in practice as variable renewable energy (i.e. semi-scheduled plant) may share a greater burden of the costs than they arguably should due to the regulation FCAS Causer Pays calculation process. The calculation of contribution factors for scheduled and semi-scheduled generation for a dispatch interval involves calculating the deviation of a unit from a linear trajectory between the previous dispatch target and the next dispatch target (i.e. the TOTALCLEARED value for the previous dispatch interval and the current dispatch interval) every 4 seconds[62]. For semi-scheduled generation, the TOTALCLEARED value is based on AWEFS for wind farms, ASEFS for solar farms or participant self-forecasting. In the case of AWEFS/ASEFS, persistence forecasts are often used. For a given dispatch interval, these persistence forecasts use active power output SCADA data from up to two minutes before the end of the previous dispatch interval to produce a forecast for the TOTALCLEARED value for that interval (see Figure 1 and Figure 2)[63]. Our analysis of SCADA and dispatch data for a week in July 2020 suggests that this translates to a persistence forecast that is lagged by approximately seven minutes, and that such forecasts appear to be in widespread use for variable renewable energy[64]. As such, Causer Pays appears to be assessing semi-scheduled plant against a trajectory that is approximately seven minutes old. We think that the use of a lagged trajectory in assessing dispatch compliance is inappropriate.

Semi-scheduled plants are consistently receiving negative contribution factors[65]. While it is unclear whether this outcome is wholly an artefact of the calculation methodology or potentially the result

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[61] Australian Energy Market Operator, "Regulation FCAS Contribution Factor Procedure," 2018, 12, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Regulation-FCAS-Contribution-Factors-Procedure.pdf.

[62] AEMO, "Regulation FCAS Constribution Factor Procedure," no. November (2018): 12, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Regulation-FCAS-Contribution-Factors-Procedure.pdf.

[63] Australian Energy Market Operator, "Scheduling Error Report: AWEFS and ASEFS Unconstrained Intermittent Generation Forecast (UIGF) Scheduling Errors - 2012 to 2016," 2016, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Market_Event_Reports/2016/AWEFS-UIGF-Scheduling-error_2012-to-2016_Republished_FINAL.pdf.

[64] Abhijith Prakash et al., "Submission to the Semi Scheduled Generator Rule Change (s) Issues Paper," 2020, 15–20, https://www.aer.gov.au/system/files/CEEM - Submission - Semi scheduled generators proposed rule changes - July 2020.pdf.

[65] "NEM FCAS causer pays factor issues for wind and solar farms," 2017, https://wattclarity.com.au/articles/2017/03/nem-fcas-causer-pays-factor-issues-for-wind-and-solar-farms/

of their active power deviations and consequent adverse impacts on system frequency control, the methodology in use for semi-scheduled generation does not seem to be fit for purpose. We cannot support this cost-allocation solution if Causer Pays (or a frequency response deviation pricing approach) uses this methodology to calculate contribution factors for semi-scheduled generation. UNSW CEEM has published research that suggests a potential solution – use the input data to predict INITIALMW (active power output at the beginning of the dispatch interval) and maintain this forecast for the entire interval[66]. The linear trajectory could then be calculated between the INITALMW values (see Figure 3). While preliminary analysis of this simple solution suggests that it reduces lag and therefore provides a better indication of compliance/deviation, we suggest this methodology be further considered by AEMO and the double-sided causer pays working group.

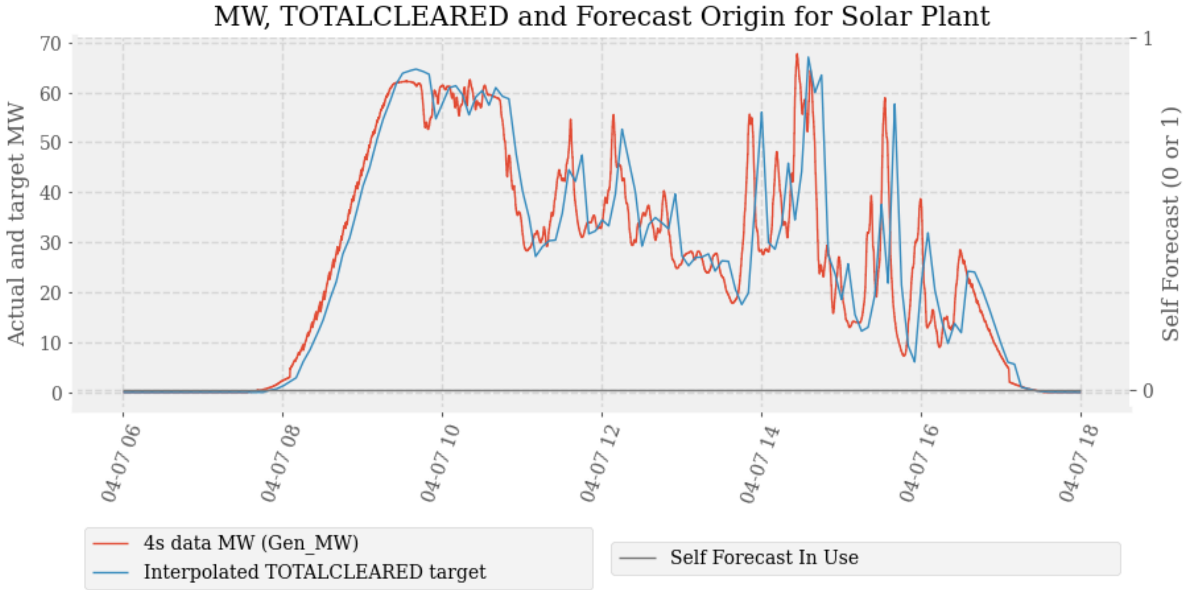

Figure 1: Active power output and dispatch levels and trajectories determined by ASEFS for a solar plant on 4/7/2020.

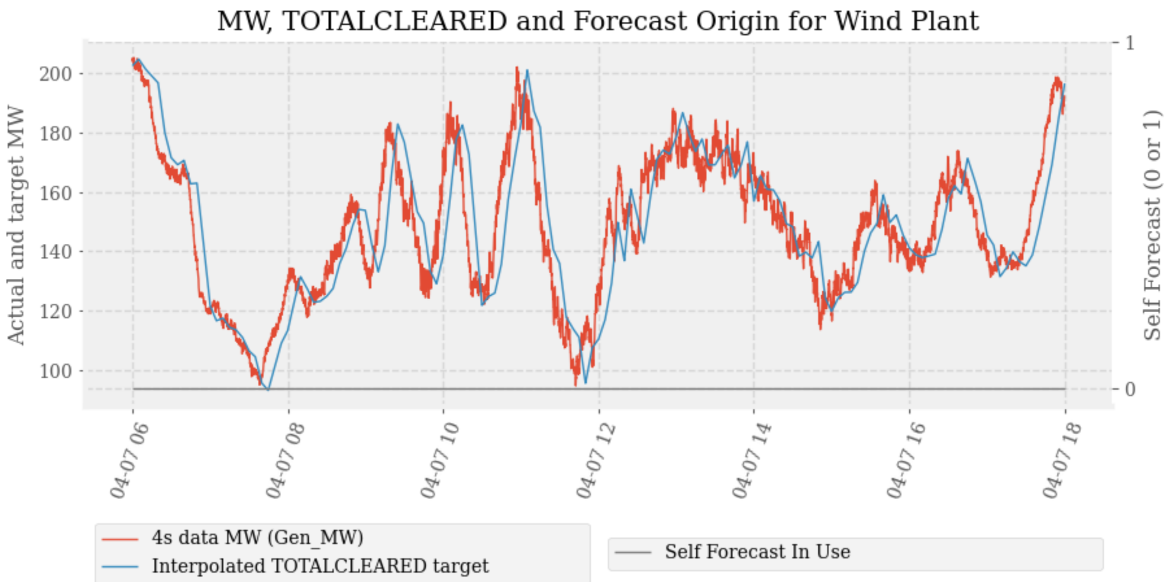

Figure 2: Active power output and dispatch levels and trajectories determined by AWEFS for a wind plant on 4/7/2020.

66 Kanyawee Keeratimahat, Anna Bruce, and Iain MacGill, "Analysis of Short-Term Operational Forecast Deviations and Controllability of Utility-Scale Photovoltaic Plants," *Renewable Energy*, no. xxxx (November 2020), https://doi.org/10.1016/j.renene.2020.11.090.

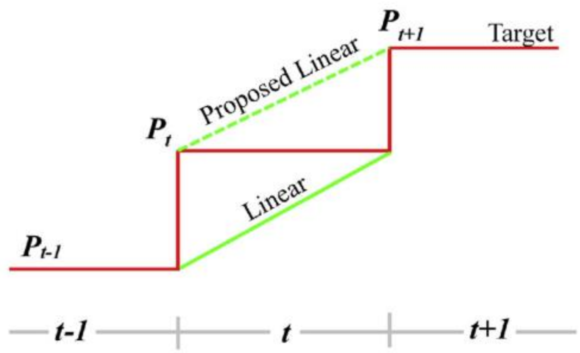

Figure 3: (Existing) linear trajectory between INITIALMW and TOTALCLEARED for dispatch interval at time t compared to the proposed linear trajectory between the INITIALMW value for dispatch interval t and t+1.

- Do stakeholders agree that the any additional costs for narrow band PFR be allocated through the existing causer pays procedure for the allocation of regulation costs (or a revised version as described in section 5.9?

  Please see our response to the previous question. In our view the existing Causer Pays procedure unfairly allocates costs to variable renewable energy participants, so we cannot support this avenue for cost-allocation. It would be preferable for the AEMC to only consider this avenue for cost-allocation if this issue can be resolved.

  Even then, we note that there is a need to further refine regulation FCAS Causer Pays to provide better (dis)incentives that encourage plant to provide effective frequency response. Some of the suggestions raised in the proposals for double-sided Causer Pays and frequency response deviation pricing warrant further investigation and we look forward to seeing progress updates from the double-sided causer pays working group.

Q17: Pathways for Enduring PFR Arrangements

- What are stakeholders' views on the enduring PFR pathways?

  We are of the view that all the pathways may have some degree of deficiency. Pathway 1 (retention of mandatory PFR with a narrow deadband) has no mechanism to procure firm headroom/footroom. Pathway 3 eliminates the mandatory PFR obligation. This may lead to the withdrawal of widespread PFR provision and the loss of power system resilience benefits that come with mandatory PFR provision. We outline our issues/questions regarding the effectiveness of Pathway 2 in response to the next question.

- Do stakeholders agree with the Commission's preliminary preference for pathway two? (the widening of the PFCB and the introduction of market arrangements for narrow band PFR)

  As discussed in our responses to previous questions, it is unclear to us whether the moderate deadband setting restricts the potential utility and additional resilience offered by mandatory PFR and whether market arrangements for tight-deadband PFR would be sufficient, particularly during complex contingencies or when a region or multiple regions are islanded. The advice being obtained by the AEMC from AEMO and an independent party will be crucial in determining if this pathway is first and foremost effective and if it is efficient. We reemphasise that we support effective outcomes over efficient outcomes where a particular system service is essential to secure power system operation during the energy transition and/or where the benefits of efficient procurement, pricing and cost-allocation do not clearly outweigh the costs.

  However, we do find elements of this pathway to be agreeable since it extends the mandatory PFR requirement and values the provision of headroom/footroom.

Q18: Future Review of the FOS

- What are stakeholders' views of the Commission's proposed approach towards a future review of the FOS as part of the development of enduring PFR arrangements?

  The proposed timing for a review of the FOS (Q3 2021) seems reasonable as it might enable:

  - AEMO and other parties to deliver technical advice on the future power system requirements and the role of PFR and FFR.
  - The AEMC to progress its work on PFR arrangements.
  - Draft arrangements for contingency FFR to be considered in the review of the FOS.

Q19: Reforms to the NER Relating to Cost Allocation for Regulation Services – Causer Pays

- What are stakeholders' views on the proposal to allocate regulation costs on the basis of performance against system frequency as opposed to Frequency indicator (FI)?

  We agree that system frequency is a better variable to use to weight deviations. Resources may deviate in response to system frequency, not FI. Furthermore, as FI contains integral components and is the sum of filtered signals, it may not adequately reflect the harm or assistance provided by a deviation from a dispatch trajectory at a given time. We also agree that system frequency is more transparent than the FI.

- What are stakeholders' views on the proposal to align the sample and application periods for determination of causer pays factors and shorten the application period to 5 minutes, in line with the NEM dispatch interval?

  We note that if the intention of regulation FCAS Causer Pays is to allocate regulation FCAS costs to resources that contribute to the need for the service, then better aligning the sample and application periods is inappropriate. It is important to note that the need for regulation FCAS for a given dispatch interval – the procurement volume, which is the sum of a base volume and a dynamically-determined value based on power system time error[67] - is somewhat dependent on the frequency performance of resources in previous intervals. That is, it may be unfair for resources dispatched in a particular interval to bear higher costs due to the poor frequency performance of other plant in previous intervals contributing to a higher procurement volume.

  However, we are of the view that this "strict" view of cost-allocation does not achieve better frequency response. Instead, we see the main purpose of regulation FCAS Causer Pays as incentivising and disincentivising helpful and harmful frequency response, respectively. With this in mind, shortening the application period is preferable to better align cost-allocation with resource performance. Whether it is preferable to shorten the application period to the sample period (i.e. every 4s) or to a dispatch interval (i.e. every 5 minutes), depends on the differences in cost, implementation and transparency between the two:

  - We anticipate that aligning Cause Pays transactions with the sample period (i.e. every 4 seconds) will be more costly due to additional resourcing and IT costs. If this is the case and the cost is significant, then it may be preferable for Causer Pays transaction to occur for each dispatch interval.

[67] Australian Energy Market Operator, "Constraint Implementation Guidelines," 2015, 27, https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2016/constraint-implementation-guidelines.pdf.

- Aggregation is not entirely undesirable but should not mask large harmful deviations. As regulation FCAS is procured and responds over a 5-minute timeframe, it is reasonable to assign costs based on resource performance across this period. However, the 5-minute factors that are calculated under the current procedure are the *average* of the FI-weighted deviations for every 4 second data point[68]. Summation, as opposed to averaging, may better ensure that the consequences of significant deviations are not tempered by aggregation.
- AEMO currently publishes 5-minute dispatch interval contribution factors for resources. If it would be difficult for AEMO to continue to do this if the application period were aligned with the sampling period, we feel that the mechanism would be less transparent.

Regardless of which application period is chosen, we still have two concerns related to the mechanism:

- There is a continued risk that forecasted high energy and FCAS prices may lead to unit curtailment or decommitment to avoid FCAS costs. Unit decommitment and curtailment (particularly that of variable renewable energy) has been observed during regulation FCAS[69] and contingency FCAS[70] price spikes, respectively. The cost-allocation mechanism should incentivise beneficial frequency response rather than incentivising curtailment or decommitment. A double-sided mechanism and greater opportunities for variable renewable energy to provide frequency control services (e.g. PFR and FFR) may assist in achieving this.
- A sampling rate of 4 seconds may alias the frequency response of fast responding plant. We suggest that Causer Pays reform consider how this might best be managed.

- What are stakeholders' views on the removal or shortening of the ten-day notice period for causer pays contribution factors?

  Shortening the notice period may better align the costs with the application period. However, we feel that the greatest gains are to be made by better aligning the sample and application periods.

- What are stakeholders' views on AEMO's proposal to pre-calculate seven sets of contribution factors including local contribution factors?

  These changes seem reasonable to us, but it is unclear if factors for each plant will need to be updated every time a new resource connects to the NEM.

- What are stakeholders' views of AEMO proposal to include non-metered generation in the residual component for allocation of regulation costs?

  The proposal to proportionally allocate residual costs to non-metered generation (in addition to market customers) seems reasonable to us. However, this allocation of costs may not be fair if non-metered generation are providing beneficial frequency response and still incurring a cost. We suggest that the AEMC and AEMO consider whether this situation is likely.

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[68] AEMO, "Regulation FCAS Constribution Factor Procedure," 17–18.

[69] Australian Energy Market Commission, "Frequency Control Frameworks Review," 2018, 111, https://www.aemc.gov.au/sites/default/files/2018-07/Final report.pdf.

[70] Australian Energy Market Operator, "Quarterly Energy Dynamics Q1 2020," 2020, 29, https://aemo.com.au/-/media/files/major-publications/qed/2020/qed-q1-2020.pdf?la=en#:~:text=AEMO has prepared this report,Q4 2019 and Q1 2019.

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