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Response to Reserve Services in the National Electricity Market Directions Paper

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11 February 2021

Sebastien Henry

Director

Australian Energy Market Commission

Lodged electronically

Dear Mr Henry,

Re: Reserve Services in the National Electricity Market

The Collaboration on Energy and Environmental Markets (CEEM) welcomes the opportunity to make a submission to the Australian Energy Market Commission's (AEMC) *Reserve Services in the National Electricity Market* 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 high renewable penetrations for what is now 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. The corresponding author for this submission is Abhijith (Abi) Prakash (abi.prakash@unsw.edu.au).

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.

The changing nature of the NEM and operating reserves

As the Directions paper notes, operating reserves can be defined in various ways, and these definitions continue to evolve as new technologies including variable renewable energy (VRE) and utility battery energy storage systems (BESS) are deployed. Conventionally, operating reserves were often defined as generating capacity available within a short interval of time to enable the power system to continue to meet demand despite possible plant failures or other major disruptions to supply. Operating reserves included both spinning reserve (from the extra generating capacity available from connected generators) as well as non-spinning or supplemental reserves, typically provided by fast start generators. There is also the concept of replacement reserves (sometimes still considered to be operating reserves) consisting of slower start plants to take over from the fast start generators.

The introduction of electricity industry arrangements that seek to establish markets for provision of at least some aspects of operating reserves, renewables that add both variability and unpredictability of supply-demand balance, and BESS that aren't spinning but can be considerably faster to respond than spinning plant, have all added to the complexity of assessing, procuring and paying for operating reserves. The NEM is not alone in having to revisit these arrangements. However, it does have current market arrangements that are unique by comparison with other jurisdictions. These is also our now world leading penetrations of variable, inverter-connected wind and solar generation. However, there are also a significant number of large BESS coming online in the NEM, and these may considerably assist in addressing the challenges to 'operating reserves' posed by these renewables.

Our submission

Below, we provide a summary of our views on the issues and reserve service options discussed in our responses to the questions posed in the Reserve Services Directions Paper.

Our preferred timeframe for a rule change

Given that the Directions paper did not assess the quantity and diversity of ramping and reserve capacity capabilities in the current NEM, our view is that there is insufficient evidence to prioritise the implementation of an operating reserve market (i.e. draft determination on an option by June 2021). If it is the case that the matter is not pressing, our view is that it would be preferable for the AEMC to make a draft determination once a review of system security needs and requirements is complete (e.g. review of the FOS), once potential pathways for progressing the ESB Post-2025 Market Design Resource Adequacy workstream are identified, and once the impact of five-minute settlement and wholesale demand response are better understood.

Our assessment of the reserve service design options

Based on our preliminary assessment of the reserve service market design options discussed in the Directions paper, our view is that the co-optimised operating reserve market option is preferable. However, we emphasise that further work is required to establish a clear need for the capabilities that a potential operating reserve service might provide, and to determine if the co-optimised operating reserve market can effectively and efficiently provide those capabilities.

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

Abi Prakash, Nick Gorman, Anna Bruce and Iain MacGill

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1. The Need to Address Variability and Uncertainty

1.1. What are stakeholder views on the issues identified, in particular, on whether the primary issue is appropriately characterised as an increased risk of insufficient in-market reserves being available to meet net demand, due principally to forecast uncertainty and net demand variability as the penetration of VRE generation increases?

Framing the issue – variability and uncertainty

We commend the AEMC on the approach taken in the Directions paper in outlining a need and purpose for explicitly procuring operating reserves in the NEM. Given that the term "operating reserves" is rather nebulous and can refer to different capabilities across international electricity industries, we are agreed that it is important that any potential discussion outline what purpose operating reserves have (or might have) and why there is a need for them in the NEM. Specifically, we appreciate the Commission separating the discussion around reserve requirements due to variability and due to uncertainty, and accounting for how current arrangements may or may not facilitate the provision of operating reserves by market participants in each case.

While definitions can vary, we use the term *variability* to refer to expected (forecast) fluctuations in the supply-demand-balance, whereas *uncertainty* refers to unexpected fluctuations in the supply-demand balance. Variability and uncertainty, of course, are interrelated to some extent but our view is that outlining the need for operating reserves in this manner better enables technical requirements, performance metrics and cost-recovery or allocation to be developed within a defined scope.

System capabilities and insufficiency

In our view, the analysis presented in Section 5 of the Directions paper implied that growing variability and uncertainty are driving the need for certain capabilities from resources in the NEM. Our view is that two *capabilities* may be required:

- *Reserve capacity* that is either online or offline and able to respond to a raise requirement within tens of minutes. In several markets, this capability is often delivered by tertiary frequency control reserves[1]. While such a service entails some ramping capability, the primary purpose of such a service is to replenish preceding FCAS reserves, particularly in power systems with longer dispatch intervals. Reserve capacity in the form of in-market reserves currently fulfils this function in the NEM as it can be dispatched to ensure sufficient energy supply and FCAS headroom is available in the next interval.
- *Ramping capability* that can meet ramping requirements. This could include expected ramps, unexpected ramps or both. Ramping can also be of concern across multiple timeframes, from intra-dispatch ramping that must be managed by Frequency Control Ancillary Services (FCAS), to sustained ramping required over a matter of hours and hence multiple dispatch intervals. Some ramping capability can be "procured" through dispatch (e.g. a linear trajectory between targets over a single dispatch period, as is currently the case in the NEM), or through a separate service such as a ramping product (as is the case in the California ISO and Midcontinent ISO markets[2]).

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[1] Farhad Billimoria, Pierluigi Mancarella, and Rahmatallah Poudineh, "Market Design for System Security in Low-Carbon Electricity Grids: From the Physics to the Economics," 2020, 20, https://doi.org/10.26889/9781784671600.

[2] Erik Ela et al., "Electricity Markets and Renewables: A Survey of Potential Design Changes and Their Consequences," *IEEE Power and Energy Magazine* 15, no. 6 (November 2017): 70–82, https://doi.org/10.1109/MPE.2017.2730827.

It is important to provide this framing as we felt that the Directions paper did not present sufficient analysis to quantify the availability and diversity of these two required capabilities over time in the NEM. Though such an analysis would only characterise the historical and current capabilities of the NEM, it would be an important starting point for considering whether reserve capacity and/or ramping capability requirements might grow, or perhaps even decline, into the future (we discuss this further in response to Question 1.3) and whether implementing a mechanism for procuring operating reserves should be a priority. Furthermore, while these capabilities have considerable overlap due to the relatively short dispatch intervals in the NEM, they are distinct enough that they can be provided through different means. This is important to consider as ramping needs can be of concern across multiple timescales, including within a dispatch interval, whilst in-market reserves are required to ensure that demand and headroom requirements can feasibly be met in the next dispatch interval and/or over multiple subsequent dispatch intervals.

A question of sufficiency

While the Directions paper did highlight how increasing variability and uncertainty pose certain challenges to the NEM, it is unclear whether in-market reserves are sufficient. As we have discussed, the analysis in the Directions paper did not analyse what capabilities are currently present in the NEM. Furthermore, "sufficiency" of in-market reserves in meeting future needs can only be assessed by modelling such capabilities. We note that in Appendix C of its Renewable Integration Study (RIS), AEMO used its Draft 2020 ISP Central generation build to model the top 1% of 1-hour ramping margins for all mainland regions of the NEM in 2025 (Figure 1) with and without VRE ramping forecast error. While this particular analysis has limitations in the context of this rule change (see response to Question 1.3), a similar approach could be taken by the AEMC to contextualise VRE ramps and ramp forecast error and provide a better indication of whether these factors are material to reliable and secure operation.

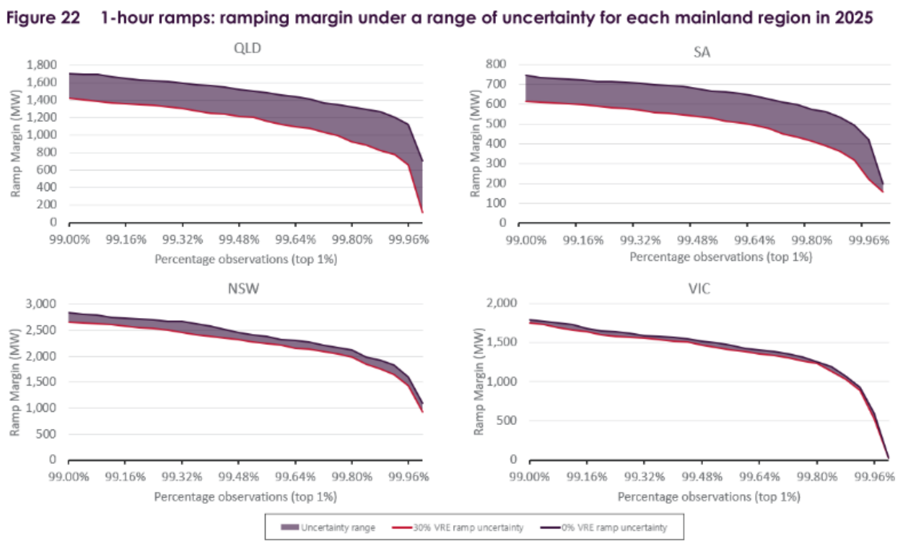

Figure 1: Modelled ramping margins for mainland NEM regions in 2025[3].

[3] Australian Energy Market Operator, "Renewable Integration Study Appendix C : Managing Variability and Uncertainty," 2020, 54.

1.2. What are stakeholder views on the materiality of these issues? For example, are the issues material enough to warrant the further development of a reserve service market?

Uncertainty needs may be more material than variability needs

As discussed in our response to Question 1.1, our view is that having a better understanding of present reserve capabilities in the NEM is important to understanding why an operating reserve service market might be needed, and how and when it should be implemented. However, assuming that these capabilities are likely to be insufficient in the future as the penetration of VRE increases in the NEM, our view is that that the need for an operating reserve service market in dealing with uncertainty is more material than the need for dealing with variability.

As highlighted by the AEMC, during expected peak periods and expected periods of high ramping "there is no clear evidence to suggest that the current arrangements…will not be sufficient to provide sufficient reserves". Incentives for ramp capability are implicit but exist. Based on their analysis of dispatch-weighted prices received by VRE generators, baseload plant and flexible plant in South Australia, Rai and Nunn concluded that there is an implicit "premium" for generator dispatchability and flexibility[4]. Furthermore, as discussed in the Directions paper, market participant contract positions are likely to incentivise participants to not only hold reserves to defend their position, but also ensure that reserves are capable of the necessary supply ramps. It is likely that such implicit price signals will be sharpened once the five-minute settlement rule change comes into effect in the NEM. However, we acknowledge that the single price nature of the NEM means that inflexible plant (e.g. baseload thermal generation) may also benefit from high prices that arise from the system need for flexibility[5].

In contrast, we are not aware of any transparent price signals that incentivise reserve capacity beyond a given dispatch interval, or ramping capability, for managing power system uncertainty. Whilst FCAS is able to address uncertainty, it does so within a dispatch interval and is designed and procured with the expectation of dispatch trajectory conformance. By procuring operating reserves, AEMO may be able to ensure that FCAS can be relieved and replenished and that the system is better able to respond to a high-ramp dispatch, which may occur when a point or ramp forecast error is observed and accounted for prior to the subsequent dispatch run.

Clarity required around current materiality of issues

Though we view the need for operating reserves driven by uncertainty as potentially more material than the need driven by variability as VRE penetration increases in the NEM, our view is that further analysis is required to justify whether these needs are material in the NEM today and whether the operating reserve market options outlined in the Directions paper are the best solutions to address these needs.

Given that the Directions paper did not assess the quantity and diversity of ramping and reserve capacity capabilities in the current NEM, we believe that there is insufficient evidence to prioritise the implementation of an operating reserve market (i.e. draft Determination on an option by June 2021). If it is the case that the matter is not pressing, our view is that it would be preferable for the AEMC to make a draft determination once a review of system security needs and requirements is complete (which could include reviewing the Frequency Operating

[4] Alan Rai and Oliver Nunn, "Is There a Value for 'Dispatchability' in the NEM? Yes," *Electricity Journal* 33, no. 3 (2020): 106712, https://doi.org/10.1016/j.tej.2020.106712.

[5] E. Ela et al., "Wholesale Electricity Market Design with Increasing Levels of Renewable Generation: Incentivizing Flexibility in System Operations," *Electricity Journal* 29, no. 4 (2016): 51–60, https://doi.org/10.1016/j.tej.2016.05.001.

Standard, which may commence in Q3 2021[6]), once potential pathways for progressing the ESB Post-2025 Market Design Resource Adequacy workstream are identified and once the impact of five minute settlement and wholesale demand response are better understood. The former is particularly important as adapting system definitions (e.g. that for "contingency") and clarifying the roles, responsibilities and service definition of FCAS (and of dispatch too) in the future NEM may change the need for the operating reserve services.

It is also unclear to us how operating reserve services as outlined in Section 6.2 might actually address power system needs. The AEMC and AEMO could provide greater clarity around the interactions and interface between variability and uncertainty, FCAS and dispatch (discussed further in response to Question 1.3). Furthermore, Appendix C of the RIS suggest that large ramps may be challenging across multiple timeframes. For example, while operating reserves may be able to assist in managing unexpected ramping events once these events are identified and accounted for in dispatch, the system may need capabilities to deal with unexpected ramping within a dispatch interval (i.e. 5-minute ramps)[7]. In our view, PFR and regulation FCAS, as they are currently defined and designed, are not best placed to handle such events, and operating reserves may be unable to assist until the subsequent dispatch interval.

As such, our view is that a more holistic approach to system security and reliability may better highlight whether the need for operating reserves is material and what, if any function, an operating reserve service might have. This is particularly important given the raft of rule changes being considered and the potential impacts of the switch to 5-minute settlements and the introduction of wholesale demand response later this year.

1.3. If not, what further information would be required relating to the nature of the issues facing the power system before progressing the development of a reserve service market?

Assessment of historical and current capabilities

As discussed in our response to Question 1.2, this suite of analysis would provide useful context and clarify whether implementing an operating reserve service market is a priority. Ideally, this analysis should also be carried out following the switch to 5-minute settlements and the introduction of wholesale demand response. The analysis could include the following:

- Analysis of bidding practices and supply curves in each mainland region and across the NEM. This would give the AEMC and stakeholders a better understanding of historical and current levels of headroom/in-market reserves, when and how often such reserves are in short supply, and which participants provide such reserves.
- Analysis of the impact of limited ramping capability on market price. While Infigen has done some preliminary analysis to assess the impact of ramping on price[8], our view is that more comprehensive analysis might assess ramping across different timeframes. In particular, the impact of ramping across a dispatch interval (5-minute ramps) could be

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[6] Australian Energy Market Commission, "Frequency Control Rule Changes," 2020, 95, https://www.aemc.gov.au/sites/default/files/2020-12/Frequency control rule changes - Directions paper - December 2020.pdf.

[7] Australian Energy Market Operator, "Renewable Integration Study Appendix C : Managing Variability and Uncertainty," 17–19.

[8] Infigen Energy, "Infigen System Services Rule Changes Submission," 2020, 12, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_infigen_-_20200813_-_erc0263_erc0290_erc0295_erc0296_erc0300_erc0306_erc0307.pdf.

assessed by analysing how often and when dispatch ramping constraints are binding and what the potential price implications may be.

Better integration of analysis from RIS

Our view is that analysis that has been carried out as a part of AEMO's RIS (notably Appendix C: Managing variability and uncertainty) could have been better integrated into the Directions paper. Notably, the RIS attempts to quantify ramping margins and the number of challenging days a region might face due to large 30-minute ramps. While the RIS reflects an optimal generation build based on ISP modelling, the analysis presented in the RIS provides an indication of what capability might be available in the NEM and is valuable for stakeholders to consider. If possible, it would be ideal for AEMO to extend this analysis to better indicate the potential level of in-market reserves in the power system and potentially model reserve capacity and ramping margins further into the future (though this of course entails greater uncertainty).

Clarity around the interfaces and interactions

Our view is that it may be valuable for AEMO and the AEMC to provide stakeholders with greater clarity around how FCAS, dispatch and operating reserves interact, or might interact, with each other. It is unclear to us how uncertainty is managed across these services and processes. For example, how does AEMO currently identify whether there is a significant point or ramp forecast error, particularly as FCAS will begin to respond to supply-demand imbalance? Once identified, how does AEMO account for such error in dispatch for the next interval? What lead time is required such that dispatch (and potentially operating reserves) can account for this error? Providing answers to questions such as these may give stakeholders a better understanding of the role and limitations of various processes and services and a greater appreciation of the benefits and limitations of a potential operating reserve service.

2. Options to Address Variability and Uncertainty of Net Demand

2.1. To what extent could any or all of the incremental improvements to current arrangements set out in section 6.1 address the issues sufficiently to negate the need to implement a new reserve service market? Are there any other incremental improvements that should be considered?

Improving the accuracy of net demand forecasts

We agree that while improving forecast uncertainty will support the NEM in meeting increasing variability and uncertainty, it is likely that forecast uncertainty will remain a material issue into the future as there are significant challenges to improving weather forecast accuracy [9]. As such, the need for reserves cannot be eliminated. To better account for the performance of VRE forecasting, our view is that it would be valuable to investigate whether reserve procurement (including that of FCAS) could reflect forecast uncertainty.

Develop and publish more information for the market

Our view is that these improvements may be invaluable in supporting market participants to commit flexible reserves where they might be required and better manage expected ramps in net demand. In particular, ramping margins or other ramping indicators are necessary as market information released by AEMO does not currently account for ramping.

Pursue potential market/system enhancements

While some analysis from U.S. ISO/RTO markets suggests that multi-period dispatch may enable the power system to meet variability at lowest cost[10], we agree that it involves significant implementation costs and challenges (particularly around how settlement might work). Furthermore, a separate product can better address uncertainty as multi-period dispatch is a deterministic process.

As suggested by responses to the ESB's Post-2025 Market Design Consultation Paper, several stakeholders (including ourselves) feel that formal ahead mechanisms (i.e. system service ahead scheduling or an integrated ahead market) are not required, or that the cost-benefit of their implementation requires further analysis[11]

Integrate emerging flexible resources

As discussed in our response to Question 1.2, if there is no immediate need for an operating reserve service, our view is that it would be beneficial for AEMO and the AEMC to assess the impacts of 5-minute settlement and wholesale demand response on energy and FCAS markets before determining why such a service might be needed and how it might address uncertainty and/or variability.

Adapting system definitions

As discussed in our response to Question 1.2, we support a review of the FOS and a holistic consideration of the objectives and design of frequency control services. Redefining "credible contingency" to better capture forecast error and widespread distributed PV trips and considering the role of regulation FCAS in managing intra-dispatch ramps should certainly be a

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[9] Australian Energy Market Operator, "Renewable Integration Study Appendix C : Managing Variability and Uncertainty," 36.

[10] Dane A Schiro, "Procurement and Pricing of Ramping Capability," 2017, https://www.iso-ne.com/static-assets/documents/2017/09/20170920-procurement-pricing-of-ramping-capability.pdf.

[11] Johanna Bowyer, "IEEFA ESB Consultation Paper Submissions Summary,", 2021, https://ieefa.org/wp-content/uploads/2021/01/ESB-Submissions-and-Directions-Paper-Table-Summary_v2.pdf

part of this review. Such a review may change the need for and hence definition of an operating reserve service.

2.2. Which of the reserve service market options set out in section 6.2 is the most preferable to address the issues raised in Chapter 5, taking into account the way different technologies may operate under each option and the trade-offs between the options?

In our response to this question, we highlight the potential roles of an operating reserve service (an aspect we feel could have been better addressed in the Directions paper) and discuss what we think may be the beneficial and detrimental consequences of these design options. Based on our preliminary assessment of these design options, our view is that the co-optimised operating reserve market is preferable. However, we emphasise that further work is required to establish a clear need for the capabilities outlined in response to Question 1.1 and if the co-optimised operating reserve market can effectively and efficiently meet those capabilities.

The potential roles of the proposed operating reserve service

Our view is that the operating reserve services proposed in Section 6.2 of the Directions Paper sit at the interface of security and reliability. We consider this service to have elements of a security product given that it might enable unforecasted demand to be met whilst relieving primary and secondary frequency control in the case of extended variability and uncertainty (e.g. forced outages or ramp forecast error). We consider this service to have elements of a reliability product in that it provides "insurance against reliability-driven curtailment" in future dispatch intervals[12].

As discussed in response to Question 1.1, the reserve service appears to be providing two capabilities.

- *Reserve capacity* that is either online or offline and able to respond within minutes. This is closer to the definition of spinning/non-spinning reserves in U.S. ISO/RTO markets, where operating reserves may be required within a call-time of 10-30 minutes[13].
- *Ramping capability* that can meet unanticipated, anticipated or all ramping requirements in the next dispatch interval (i.e. 5 minute ramping), within the next 30 minutes or the dispatch interval after 30 minutes has passed. We note that California ISO has implemented a 5-minute ramping product that is designed to deal with uncertainty (similar to the co-optimised operating reserve market option) whilst Midcontinent ISO has implemented a 10-minute ramping product due to insufficient ramp capability in dispatch (an element of which is captured in the ramping commitment market option)[14].

Due to the reserve service options providing two capabilities (reserve capacity and ramping capability), price signals for flexibility and capacity may be blurred as scarcity pricing for reserves could be linked to either (or both) capabilities. This is potentially no different from current arrangements, whereby wholesale energy market prices might spike to due to ramping

[12] Billimoria, Mancarella, and Poudineh, "Market Design for System Security in Low-Carbon Electricity Grids: From the Physics to the Economics," 21.

[13] Erik Ela et al., "Alternative Approaches for Incentivizing the Frequency Responsive Reserve Ancillary Service," *Electricity Journal* 25, no. 4 (2012): 88–102, https://doi.org/10.1016/j.tej.2012.04.015.

[14] Ela et al., "Wholesale Electricity Market Design with Increasing Levels of Renewable Generation: Incentivizing Flexibility in System Operations"; Schiro, "Procurement and Pricing of Ramping Capability."

requirements, a low level of in-market reserves, or both. We would encourage the AEMC to consider whether incentives for flexibility ought to be separate to incentives for reserve capacity, and if so, whether the reserve service functions being considered are appropriate.

An additional role for an operating reserve service that was not explicitly discussed in the Direction paper is that it can enable the demand-side preference for reliability to be better reflected in wholesale market prices. Ideally, vigorous demand-side bidding would lead to wholesale market prices that reflect energy consumers' preference for reliability. In its absence, the Reliability Panel sets a NEM-wide reliability standard and determines an appropriate market price cap to support this standard, but also to minimise participant exposure to high prices and mitigate the exercise of market power. The consequence of this is that the spot market cap, though relatively high in the NEM, is generally well below the estimated value of customer reliability for both residential and non-residential sectors and across NEM states[15]. A price for operating reserves that reflects the loss of load probability can place a premium on energy during scarcity period and thus better reflect the value of customer reliability[16].

However, we feel that it is important to point out that an operating reserve service market is not a good substitute for demand side participation and the development of a two-sided market. If an energy user does not wish to pay for a certain level of reliability, a two-sided market could enable that user to express a preference and price for generation/load curtailment. As such, if the costs of the operating reserve service are allocated on the basis that the service improves reliability, additional costs may be imposed on consumers that would rather be curtailed. This could be partially addressed in two ways. Firstly, wholesale demand response could express a preference for a degree of curtailment in their energy bid and bear operating reserve costs for their remaining load. Secondly, given that an operating reserve service prevents reliability-driven curtailment of load (and potentially of flexible generation such as VRE) for subsequent dispatch intervals, it could be characterised as a club good as users that are unwilling to pay for the reliability premium could be preferentially curtailed[17]. However, we expect that the second option would increase market complexity and may not deliver sufficient benefits due to the market structure of the NEM.

Our view is that the AEMC and AEMO should, as this work progresses, place a particular focus on identifying and quantifying potential costs and benefits to consumers. For example, it would provide clarity to stakeholders to better understand whether enablement or activation costs are more significant for RERT over various timeframes and for potential cost savings in RERT activation to be quantified.

Our assessment of reserve service design options

a) Reserve horizon

Our view is that it would be ideal for the reserve horizon (i.e. the interval(s) in which the reserve is required) to match the optimisation horizon (i.e. the period of a dispatch interval). In the NEM, this would mean that operating reserves procured in one dispatch interval be available and ready to respond in the next. Of the options discussed in the Directions paper, only the co-optimised operating reserve market has this feature. Our view is that this would be preferable for the following reasons:

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[15]Australian Energy Regulator, "Value of Customer Reliability Review – December 2019," https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Factsheet%20-%20December%202019.pdf

[16] William W. Hogan, "Electricity Scarcity Pricing through Operating Reserves," *Economics of Energy and Environmental Policy* 2, no. 2 (2013): 65–86, https://doi.org/10.5547/2160-5890.2.2.4.

[17] Billimoria, Mancarella, and Poudineh, "Market Design for System Security in Low-Carbon Electricity Grids: From the Physics to the Economics," 21.

1. Forecasting accuracy generally improves closer to the actual dispatch interval[18]. Procuring operating reserves closer to their potential dispatch may enable the latest system state and information to be accounted for and may thus augment procurement efficiency.
2. One insight from the implementation of ramping products in U.S. ISO/RTO markets is that if the reserve horizon matches the optimisation horizon, the service is better placed to ensure that demand can feasibly be met[19]. Figure 2 provides an example of how longer horizon ramping might be insufficient and is relevant to the callable operating reserve market option and the ramping commitment market. Whilst the co-optimised availability market only requires availability in a single dispatch interval, this availability may become insufficient as forecast uncertainties become clear over the course of 30 minutes. 5-minute ahead procurement is the most flexible option and the most likely to ensure feasibility.

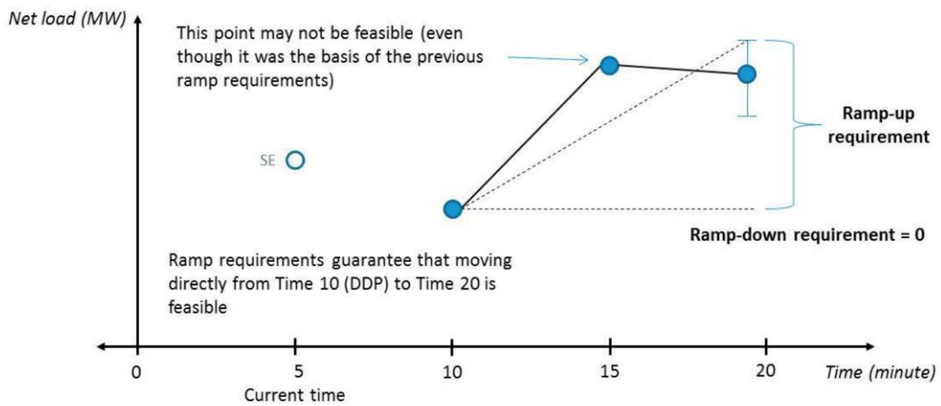

Figure 2: Ramping feasibility issues in the Midcontinent ISO market. The ramping product is procured at Time 5 to ensure that ramp from Time 10 to Time 20 is feasible. However, uncertainty could lead to higher than forecast demand in Time 15 and may not be addressable by procured operating reserves[20].

Explicit valuation of fast ramping capability is also problematic for a 30-minute reserve horizon. A relatively inflexible unit could conceivably provide availability for a dispatch interval in 30 minutes time by modifying its bids such that it would be able to ramp over the next 25 minutes (a similar situation could be envisaged in a callable operating reserve market with a call-time). While this could occur with a 5-minute horizon reserve service, there is a greater onus on the participant, rather than the system, to manage revenue risk due to unit inflexibility as a 5-minute reserve horizon only remunerates a plant with reserve that can be available for dispatch in the next 5 minutes. Our view is that fast flexibility will be valuable in a NEM with growing uncertainty and variability and may be better incentivised under a 5-minute reserve horizon. Additionally, flexibility that can respond to longer duration ramps may still be incentivised under a 5-minute reserve horizon. If longer duration ramps are common, then units able to provide reserve service throughout the ramping period will be well placed to earn revenue in the reserve market.

Our view is that the AEMC did not provide sufficient justification for considering a 30-minute operating reserve horizon. We suspect three reserve options have a 30-minute horizon to

[18] Australian Energy Market Operator, "Renewable Integration Study Appendix C : Managing Variability and Uncertainty," 38.

[19] Schiro, "Procurement and Pricing of Ramping Capability."

[20] Schiro.

increase participation in a potential reserves service market as dispatch in the NEM currently accommodates for fast-start units, which must be able to synchronise and reach their minimum operating level within 30 minutes[21]. If this is the case, we note that there is a diversity of providers (OCGT, conventional thermal, hydro, battery, demand response, etc.) in the market for raise delayed (5-minute) FCAS, which has similarities to a potential reserve service (see Figure 3). We encourage the AEMC to outline its reasoning and provide any analysis that might support this design option.

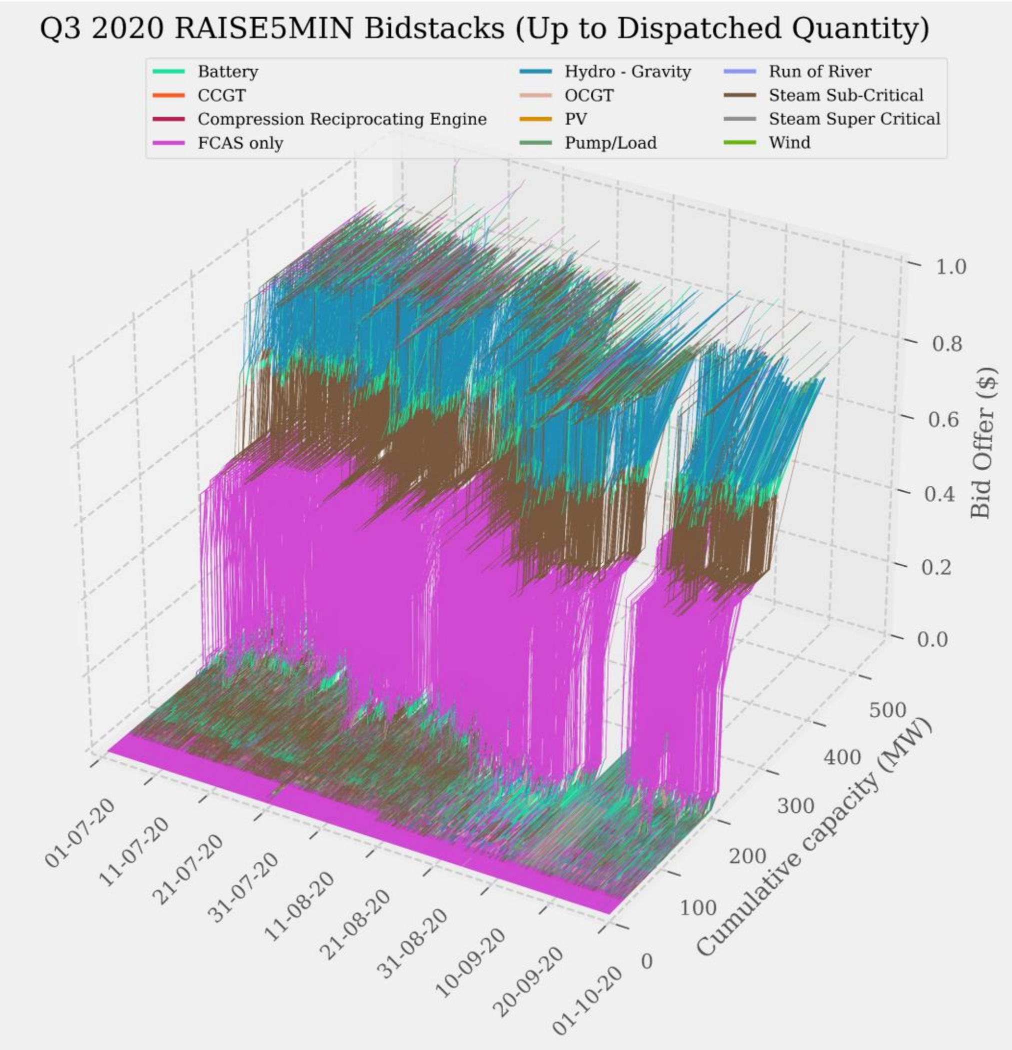

Figure 3: Global NEM supply curve for raise delayed FCAS in Q3 2020 by technology (FCAS only includes market ancillary service providers). Note that this is a supply curve and does not account for dispatch constraints (e.g. FCAS trapezium constraints, regional constraints, etc.).

b) Level of (co-)optimisation

Our view is that the various options offer different levels of system optimisation.

Even if a reserve service is not co-optimised with energy and FCAS, provision of a separate ramping/availability service by a particular unit would likely need to be subject to security constraints (e.g. network flow constraints). As such, we can envisage an outcome whereby the operating service market outcome may be optimal but the whole-of-system outcome is not.

[21] Australian Energy Market Operator, "Fast-Start Inflexibility Profile - Process Description," 2014, https://www.aemo.com.au/-/media/Files/PDF/Fast_Start_Unit_Inflexibility_Profile_Model_October_2014.ashx.

Our view is that co-optimisation of a reserve service with energy and FCAS is preferable as operating reserve is linked to energy provision and because co-optimisation offers both operational and economic benefits. Dispatch can incorporate physical unit constraints, including ramp rates and technical envelopes (e.g. FCAS trapeziums). By allowing technical feasibility of energy and service provision to be managed by the system through dispatch rather than managed by participants, the risk of service non-delivery due to technical constraints is reduced. Furthermore, co-optimisation reflects the opportunity-cost incurred by providing a service and hence ensures that a participant is incentivised to provide a service during high energy prices[22].

c) Energy market impacts

It is likely that all reserve service options will have some impact on the energy market. However, our opinion that it is preferable for an option to maximise incentives and value for unit flexibility whilst minimising distortion to the energy market.

It in unclear to us how the callable operating reserve market and the ramping commitment market would actually operate alongside the energy market. The Directions paper suggests that a callable operating reserve service would, when called upon, "displace the dispatch of capacity in the energy market". As the Directions paper does not discuss what power system conditions may lead to reserve being called upon, it is difficult to assess the degree of distortion that might be experienced in the energy market. The Directions paper also suggests that the ramping commitment service would meet both expected and unexpected ramping needs. It is unclear to us how a ramp might be differentiated from energy provision if this service were implemented. Furthermore, Figure 6.4 in the Directions paper implies that the energy market would no longer be responsible for meeting net demand changes. This operation style resembles that of a vertically-integrated utility (i.e. baseload plant supplying energy whilst load-following plant meet ramps in net demand). Assessing the merits of such a major change in power system and market operation is appropriate for a market or power system design process and not a rule change process.

Further considerations

- It is unclear how the costs of this service would be best allocated, given that its procurement could be driven by AEMO forecasting errors and/or complex power system events.
- While it was not explicitly stated in the Directions paper, we hope that the AEMC is also considering the procurement of downwards ramping capability/footroom. Given that many thermal plants have minimum operating levels, these capabilities will be required during energy transition.

2.3. Are there any other reserve service market options not presented here (or variations on the options, such as the variation discussed in section 6.2.3) that would be preferable? If so, why?

- VRE can be operated flexibly and curtailed to provide system flexibility. In the short-term, we do not consider this option preferable as zero emissions energy may be spilt to ensure emissions-intensive generation can stay online. However, as AEMO has outlined, it is likely that flexible operation of VRE, including curtailment, will be required to manage variability

[22] Erik Ela et al., "Effective Ancillary Services Market Designs on High Wind Power Penetration Systems," *IEEE Power and Energy Society General Meeting*, 2012, 1–8, https://doi.org/10.1109/PESGM.2012.6345361.

and uncertainty as VRE penetrations increase. Our view that the provision of this service should not go unremunerated - market mechanisms should seek to reward this flexibility and should not hinder energy transition.

- It is unclear what the relative costs and benefits are of procuring separate ramping and/or reserve capacity products. Further analysis of current market conditions, assessment of incoming market changes and a comprehensive review of FCAS and the FOS are likely to assist in assessing whether capabilities should be separated or bundled.
- The maximum level of flexibility being proposed for operating reserves is response after one dispatch interval, however, based on AEMO's modelling in the RIS, intra-dispatch ramping and uncertainty is also likely to pose challenges as penetrations continue to climb. In particular, PFR and regulation FCAS are not currently designed or procured to handle estimated ramp forecast uncertainty. We see two potential options for addressing this issue. The first is that, if the review of FCAS and the FOS deems it appropriate, regulation FCAS be modified to include a ramping capability (in MW/s) in addition to regulation capacity (in MW). When coupled with a payment premium for performance, regulation FCAS could be paid to provide regulation faster, further and more accurately. The second option is implementing a separate intra-dispatch load-following or ramping product. The potential interactions between this service, existing linear dispatch trajectories and regulation FCAS would need to be considered.

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