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Mr Dominic Adams
Australian Energy Market Commission
Sydney South NSW 1235

By online submission

AEMC ERC0295

Dear Mr Adams

Submission to the AEMC's Directions Paper – Reserve Products in the NEM

The Australian Energy Market Operator (AEMO) welcomes the opportunity to comment on the AEMC's Direction Paper on Reserve Products in the NEM.

The Directions Paper asks questions on what a product would be used for and how it could be designed. In Attachment 1 AEMO responds to these questions in detail, broadly summarised below.

The paper discusses whether the increased variability and uncertainty in the power system warrants a new operating reserve product.

This submission recognises a wide range of current and emerging sources of uncertainty and risk for the secure and reliable operation of the NEM. These have a range of measures to address them including system planning, standards, and procedures, alongside the market reforms being addressed by the ESB Post-2025 Market Design Program.

In regard to the specific question of increased net demand uncertainty over operational timeframes, this submission largely agrees with the premise of the Directions Paper and supports the development of a new operating reserve product. AEMO provides information on how the issues raised in the Directions Paper relate to current and future market processes and dynamics. Whilst AEMO recognises that market participants may adapt to supply additional operating reserves at times of greater uncertainty, current frameworks do not provide assurance that operating reserves will be provided to levels sufficient to address the issues raised in the Directions Paper. On this basis, AEMO believes a new operating reserve product is warranted. In particular, AEMO notes:

- The uncertainty and variability of NEM net demand is increasing
- Interventions due to uncertainty in net demand have not occurred in the past
- The short-term projected assessment of system adequacy (ST PASA) and Lack of Reserve (LOR) intervention frameworks are currently being reviewed, including the consideration of concepts of contingencies, and forecast uncertainty. Going forward, forecast uncertainty could become a greater contributing factor to intervention.

- As the energy transition progresses, it is expected there will be a higher demand for flexible resources to be online and ready to be dispatched up and down to match variability and uncertainty in supply and demand. Without a new reserve service, interventions may increase due to the lack of suitable flexibility that can physically respond to the increasing demands.

AEMO considers the aims of any new product should include:

(a) Enough reserves are available and physically realisable to allow the generating (and demand response) fleet to meet changes in net demand, accounting for the uncertainty in these changes.

(b) Reduce the need for the system operator to intervene as a result of uncertainty and variability in supply and demand to ensure power system security and reliability; and

(c) To address the points above in a way that:

   i. supports the provision of the service from a wide range of resources including traditional load following resources, but also flexibility from the demand side, energy storage and variable renewables.

   ii. creates market incentives for flexible resources that would otherwise be out of market; and

   iii. accounts for the trade-off between greater security and reliability, and higher costs to consumers.

AEMO suggests a co-optimised reserve market will help improve incentives for reserve capacity to be available for deployment when required, and notes that this may also have implications for resource adequacy and the provision of synchronous services which should be considered along the corresponding market design initiatives of the ESB Post-2025 Market Design Program.

With regards to the specific design of a reserve market product, of the four options, AEMO considers the Co-optimised Availability Product is the most suitable for the following reasons:

- a market for firm 'availability' 30-minutes ahead will support operator confidence that sufficient capacity will be available to dispatch as energy, accounting for uncertainty in net load, and still allow intervention if availability does not materialise (unlike the 5-minute Co-optimised Reserve Market);
- the option allows resources that receive payment for availability to continue to participate in the spot-market, supporting greater efficiency (unlike the Callable Operating Reserve Market and Ramping Commitment Market); and
- it provides opportunity for a broader range of resources to compete than the 5-minute Co-optimised Reserve Market.

The Co-optimised Availability Product timeframe is presented as 30-minutes. This may be appropriate, yet please note work is needed both in the short-term and on an ongoing basis to assess appropriate interactions with AEMO's forecasting and intervention timeframes and procedures, and that a longer rather than shorter duration may be preferred.

In summary, AEMO supports the development of an operational reserve / ramping product along the lines of the 30-minute co-optimised availability product. However, final endorsement for the product would need to consider further detailed design considerations such that it is able to provide appropriate incentives for the right amount of flexibility, genuinely avoid the need for interventions and a design that minimises implementation costs. The beneficiaries of this product would need to be identified and the implementation and on-going operational cost would need to be fully recovered from Participant fees. In progressing this rule change process in parallel with the ESB's post-2025 market design program and other market reform initiatives, it is important that congruency with these other reforms is continually considered.

AEMO looks forward to working with the AEMC and other stakeholders throughout this process.

Should you wish to discuss any of the matters raised in this submission, please contact Kevin Ly, Group Manager - Regulation on kevin.ly@aemo.com.au

Yours sincerely

Violette Mouchaileh
Chief Member Services Officer

Attachment 1: AEMO's High Level Consideration of the Directions paper

ATTACHMENT 1: AEMO'S HIGH LEVEL CONSIDERATION OF THE DIRECTIONS PAPER

QUESTION 1: THE NEED TO ADDRESS VARIABILITY AND UNCERTAINTY

(i) **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?**

AEMO agrees that 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. The response to question 1(ii) describes the drivers of this issue and assesses its materiality.

This section outlines the mechanisms through which the primary issue characterised above translates to an increased risk of operator intervention. This risk is a key reason for AEMO's support of further development of an in-market product that explicitly values and procures operating reserves. This submission uses the term procurement in reference to either in-market or out-of-market resources. This is in alignment with language used in the directions paper regarding the proposed product options.

This submission uses the term reserves to mean generating or demand response capacity that is currently unused but available to meet changes in the supply-demand balance. Strictly, the definition used is consistent with the 'Lack of Reserve (LOR) Reserve' output of the optimisation that occurs currently in AEMO's short term projected assessment of system adequacy (ST-PASA) [1]. This submission also explores the concepts of ramping capacity or operating reserve; the idea that reserve capacity is realisable to different degrees across different time horizons. All of the 'operating reserve' product proposals described in the directions paper are procuring reserves to the extent they can be converted to energy over a given time horizon.

This submission uses a definition of net demand consistent with the *2020 AEMO Renewable Integration Study* (RIS) i.e. underlying demand net of VRE generation, that is, demand that must be met by scheduled generation sources and not by wind or solar (including utility solar and distributed solar PV resources) [2].

In the coming sub-sections we first explore participant decision making under conditions of uncertainty, followed by a discussion of the Forecast Uncertainty Measure (FUM) and the current LOR framework, and finally the evolving reserve and intervention frameworks with which any new reserve service would interact.

1 Short term PASA process description: https://aemo.com.au/-/media/files/pdf/0431-0004-pdf.pdf
2 https://www.aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-c.pdf?la=en

Decision making under uncertainty

NEM participants currently make a variety of commercial decisions about their portfolios under conditions of uncertainty. Key sources of uncertainty are highlighted in the response to question 1(ii). On operational timeframes, the decisions that are influenced by uncertainty include, but are not limited to:

- When and if to commit generating assets or demand response resources
- To what level of output to commit resources, given technical constraints such as ramp rates
- How to manage fuel (water, gas, coal etc.)
- How to manage participation in gas and other markets
- How to manage battery state of charge
- Bidding strategies, accounting for bidding strategies of competitors

There are existing processes through which AEMO conveys information to market participants about uncertainty and its commercial and physical implications. This information may support participants in assessing expected market outcomes and risks associated with their decisions. Examples include:

- 10% and 90% probability of exceedance operational demand forecasts[3]
- Pre-dispatch sensitivities[4]
- Demand forecast accuracy assessments[5]
- Temperature forecast accuracy reports[6]
- The forecast uncertainty measure (FUM), and associated reporting[7]

There is opportunity to provide different or new information to market participants (explored further in responses to question 2(i)) to support their visibility of potential future high prices and other market outcomes, and AEMO looks forward to engaging with the AEMC and stakeholders on this as their needs evolve.

The FUM and the current lack of reserve framework

AEMO declares forecast 'lack of reserve' (LOR) conditions when the level of in-market reserves is expected to fall below certain thresholds. As discussed in responses to question 1(ii), LOR declarations influence when AEMO intervenes in the market. Specifically, if it is projected that:

3 DEMANDOPERATIONALFORECAST table of AEMO MMS Data Model – v4.30: https://nemweb.com.au/Reports/Current/MMSDataModelReport/Electricity/MMS%20Data%20Model%20Report.htm

4 https://aemo.com.au/-/media/files/pdf/pre_dispatch_sensitivities_6_1_march_2014.pdf

5 For example, Summer 2019-20 Operations Review: https://www.aemo.com.au/-/media/files/electricity/nem/system-operations/summer-operations/2019-20/summer-2019-20-nem-operations-review.pdf

6 For example, Temperature Forecast Analysis for Summer 2019-20: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/load-forecasting/temperature-forecast-analysis-for-summer-2019-20.pdf?la=en

7 https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation/nem-lack-of-reserve-framework-quarterly-reports

- A shortfall of reserves will occur, then a 'forecast LOR3' is declared
- The occurrence of the single largest credible contingency in a region would result in a shortfall of reserves, then a 'forecast LOR2' is declared
- The occurrence of the two largest credible contingencies in a region would result in a shortfall of reserves, then a 'forecast LOR1' is declared

In real time, AEMO also makes 'actual LOR' declarations corresponding to each of the cases above. These thresholds are described in further detail in AEMO's *Reserve Level Declaration Guidelines*[8].

The FUM is derived from all forecast inputs into the ST PASA process. It is the aggregated level of error in the reserve[9] forecast that would be expected to be exceeded less than 5% of the time. The FUM is reported at half-hourly resolution up to 72 hours ahead of real time. If the FUM is larger than the largest credible contingency in a region, then it sets the LOR2 trigger (if the FUM is larger than the two largest credible contingencies, it sets the LOR1 trigger). This means the FUM highlights situations where there is a reasonable probability of low reserve conditions in real time, even if the expected outcome is that reserves will exceed the deterministic thresholds based on a region's largest contingencies.

Reserves and intervention under current frameworks

AEMO has an obligation to ensure the system can return to a secure state within 30 minutes of any credible contingency event[10]. On this basis, AEMO may intervene in the market, either through direction or the exercise of *reliability and emergency reserve trading* (RERT) in response to low reserve conditions. If all relevant resources can provide the necessary response within 30 minutes, then AEMO may only need to intervene post-contingency (i.e. actual LOR3)[11]. If relevant resources require more than 30-minutes, then intervention will need to occur in response to LOR2 at a latest time to intervene based on the technical characteristics (for example response time, synchronisation time, start time and ramp rates) of the resources involved.

AEMO notes that the processes described above are not proposed to change with the advent of an operating reserve product[12], but rather one of the aims of an operating reserve market is to reduce the occurrence of circumstances where the processes are required.

AEMO has historically declared forecast LOR2 conditions based on the FUM many times. For example, in quarter 4 2020, AEMO made 7 forecast LOR2 declarations based on the FUM[13]. However, since uncertainty tends to decrease with a shortening time horizon (Figure 1), it has

8 https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Reserve-Level-Declaration-Guidelines.pdf
9 Strictly, the FUM value reflects regional excess supply (RXS), not LOR reserve.
10 NER clause 4.2.4
11 For example, if all RERT providers were type 1 (response within 30-minutes).
12 Though th***resholds*** may be impacted by the ST PASA Redevelopment Project
13 And 4 forecast LOR2 declarations based on the largest credible risk.

historically not been the case for the FUM to still exceed the largest credible contingency at the latest time to intervene.

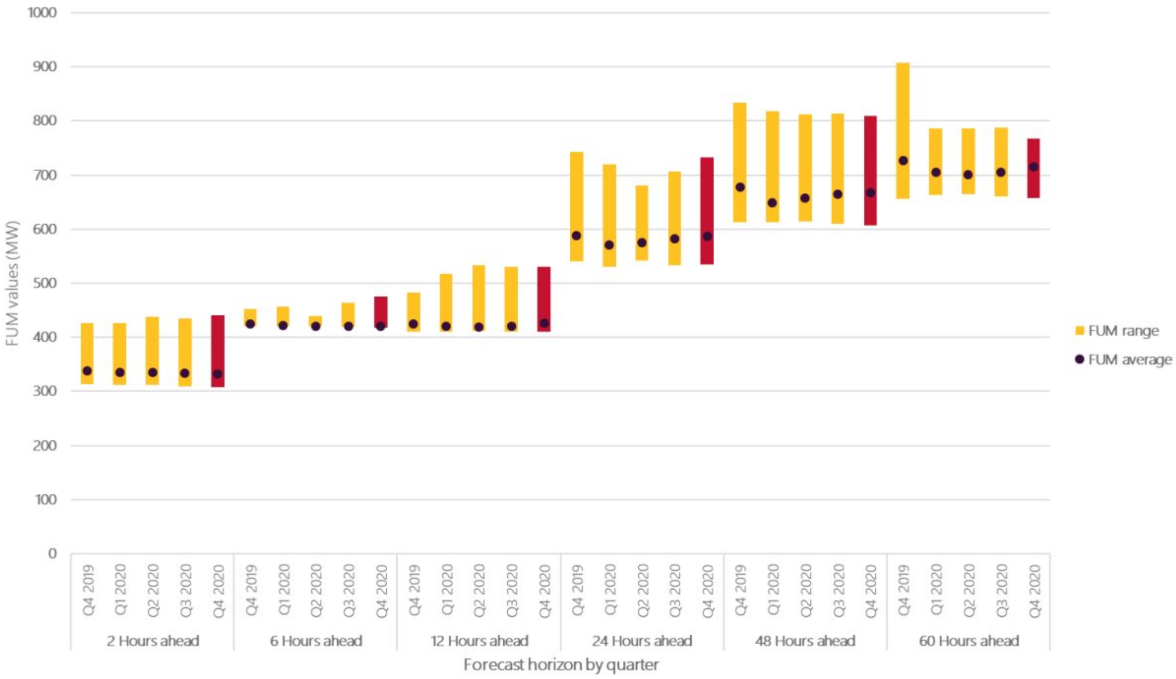

Figure 1 - Queensland region: maximum, minimum, and average FUM values for quarter 4 2020 and the previous four quarters. From NEM Lack of Reserve Framework Quarterly report.

This means that, although the FUM has triggered forecast LOR2 declarations on many occasions, it has not directly led to intervention. However, future expectations of higher net demand forecast uncertainty (question 1(ii)) equate to expectations of a higher FUM. In turn, this increases the likelihood that the FUM (to the extent it remains part of the intervention framework) will set the LOR2 trigger at the latest time to intervene in the future.

<u>Reserves and intervention under evolving frameworks</u>

An important consideration of this work is that reserve and intervention frameworks are undergoing significant review as part of the proposed ST PASA replacement project[14]. Please note that the specific changes described in this section are subject to ongoing detailed design and project approvals. This project is proposed to be implemented in the market in quarter 3 2022.

It is proposed that:

- ST PASA will determine 'uncertainty margins' taking into account uncertainties in demand forecasts, VRE forecasts and scheduled unit forced outage rates
- Different uncertainty margins will be determined based on different confidence levels applying to forecast error distributions

[14] https://aemo.com.au/en/initiatives/trials-and-initiatives/st-pasa-replacement-project

- Forecasts and their associated uncertainty margins will be determined at individual generation and load buses
- Forecasts at each bus will be adjusted by these uncertainty margins before input to the full network model used in determining reserve deficits at the corresponding confidence level
- Uncertainty margins will be used as thresholds for intervention, rather than LOR thresholds which may be based on the FUM (Figure 2)

With these changes, the frequency of intervention compared to current processes will ultimately depend on the confidence levels chosen. Confidence levels are intended to be consistent with achieving the reliability standard[15].

As discussed, under current frameworks, net demand forecast uncertainty is linked to reserves and intervention under current frameworks through the FUM, depending on its size relative to a region's largest credible contingencies. Under proposed future frameworks, forecast uncertainty will influence the reserve deficits associated with a given confidence level, regardless of credible contingency sizes. This strengthens the link between net demand forecast uncertainty (including VRE uncertainty) and intervention.

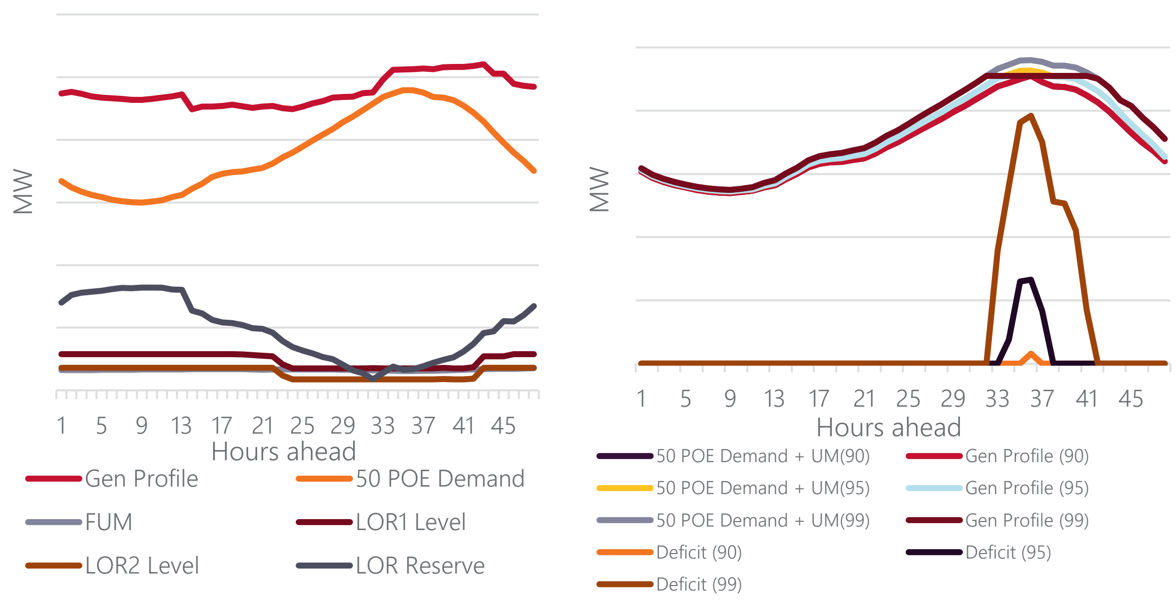

Figure 2 – Schematic of current ST PASA process (left) vs updated (right)

The ST PASA Replacement Project is a substantial reform and the changes highlighted above should be viewed in the context of a suite of proposed updates, including:

- Accounting for ramping constraints in reserve calculations

[15] ST PASA Replacement Project – Industry Update (Dec 20). https://www.aemo.com.au/-/media/files/initiatives/st-pasa-replacement-project/st-pasa-replacement-project---industry-update-dec-20.pptx?la=en

- Replacing the regional reserve model with a full network model for reserves

Demand and near-term impact on the frequency of directions

AEMO observes that the four reserve service procurement options presented in the directions paper do not describe in detail an accompanying operating reserve demand curve (ORDC). Since one of the aims of an operating reserve product is to reduce the incidence of operator intervention, AEMO considers that the ORDC should align with the intervention framework. The appendix depicts how an ORDC could be formed to achieve this objective under current or future reserve frameworks. This ORDC is conceptually compatible with any of the procurement proposals, though would be calculated differently for each, and hence the interaction of the ORDC with each proposal should be considered carefully in the evaluation of proposals.

Even if the ORDC aligns with the intervention framework, this does not guarantee that market intervention is avoided. For example, in quarter 1 of 2020, AEMO activated RERT on four occasions in response to LOR2 conditions. In each of these cases, all technically available generating capacity in the relevant regions had been made available, sufficiently incentivised by virtue of energy market signals. This means that, ignoring the potential for any dynamic efficiency effects, an operating reserve product would not have improved the reserve situation.

Ultimately, the question of whether intervention is necessary in the types of scenarios seen on peak demand days in early 2020 depends on whether sufficient capacity is available in the power system. On investment timeframes, an explicit price for operating reserves may address a lack of in-market capacity by:

- Encouraging investment in flexible dispatchable generation, demand response capability or storage
- Delaying the retirement of existing assets
- Encouraging demand response providers, like RERT providers, to participate in the central dispatch process

AEMO notes there is a high degree of uncertainty that an operating reserve service would deliver any of the above outcomes, with investment-style decisions in the NEM influenced by a host of complex issues.

AEMO also notes that an operating reserve service may have implications for the provision of synchronous services by providing additional incentive for resources to be online and available for ramping, which in turn may have implications for system planning.

AEMO suggests any implementation of a new operating reserve service should be considered alongside the entire range of ESB Post-2025 reforms, and in particular the Resource Adequacy Mechanism workstream and any mechanism for the structured procurement of synchronous services.

On operational timeframes, the value of an operating reserve market is in:

- Providing a signal for dispatchable capacity in cases of high net demand forecast variability and uncertainty, where the current commercial environment, including the pre-dispatch energy price, would not have provided sufficient incentive. Such cases are likely to become more common[16].
- Ensuring the fleet is positioned with enough flexibility to meet a broad distribution of future net demand outcomes. The size of net demand ramps (both forecast and unforecast) is expected to rise.

Discussion of the extent to which energy market signals may be sufficient to meet the needs described above is included in response to question 2(i). Discussion of the growing need for flexible supply is included in the following section.

(ii) 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?

AEMO recognises a wide range of current and emerging sources of uncertainty and risk for the secure and reliable operation of the NEM. These have a range of appropriate measures to address them including system planning, standards, and procedures, alongside the market reforms being addressed by the ESB Post-2025 Market Design Program.

Regarding the specific question of increased uncertainty and variability of net demand over operational timeframes, AEMO considers that the issues described in the response to question 1(i) are material enough to warrant the further development of a reserve service market. This section will provide evidence in support of this position. AEMO's position is premised on the expectation that the need or demand for operating reserves is growing substantially relative to its supply.

It should be noted that AEMO's expectations about the future power system and its participants will always include some element of uncertainty. AEMO believes the counterfactual cost of no action should also be considered carefully.

If an operating reserve market were needed, and one was not implemented then this may result in frequent intervention and/or supply interruptions, potentially rectified through high-cost investments or government intervention. In any such case, the impact on consumers is severe.

In contrast, if an operating reserve market were not needed, and one was implemented, in principle, the market would clear at very low prices, meaning a small impact on consumers. Consumers may still be left with a substantial implementation cost, however, which should be factored into assessments.

16 It is arguable that such cases are common already, however are masked by directions to dispatchable generators for system strength.

Supply of operating reserve

As defined in the response to question 1(i), operating reserve is available capacity that is currently unused. Conventionally, this has been synonymous with scheduled generator headroom. Generator headroom cannot be instantaneously converted to energy, so is realisable to different degrees across different time horizons. Figure 3 and Figure 4 capture an aggregated view of this dynamic, but, for simplicity, show scheduled generator capacity rather than reserves, as the former is a static value. Given the many assumptions listed below, it is likely that the numbers in the figures optimistically portray ramping capacity[17]. However, the figures are not intended to precisely reflect system capability, rather, Figure 3 is intended to capture the regional dimension to ramping capability and Figure 4 is intended to capture how it is changing over time.

The following assumptions are made:

- Start-up time and minimum stable generation levels are ignored
- State of charge or energy limitations have not been considered
- Units are able to ramp from zero to their maximum output at the max ramp rate reflected in the *2020 Integrated System Plan (ISP) inputs and assumptions workbook*[18]
- Future capacity withdrawals reflect commitments according to AEMO's generation information process (August 2020)[19]
- Future capacity additions (all either storage or demand-side participation) reflect the ISP central scenario (Development path 1) are flexible to their full output over 5 minutes
- 2015 data reflects registration status, and therefore includes some plant that may have been mothballed/retired by 2015 e.g. Redbank Power Station

17 RIS appendix 5.2 includes discussion of how the fleet's ramping capability may be affected by various practical sensitivities: https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-c.pdf?la=en

18 https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios

19 https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

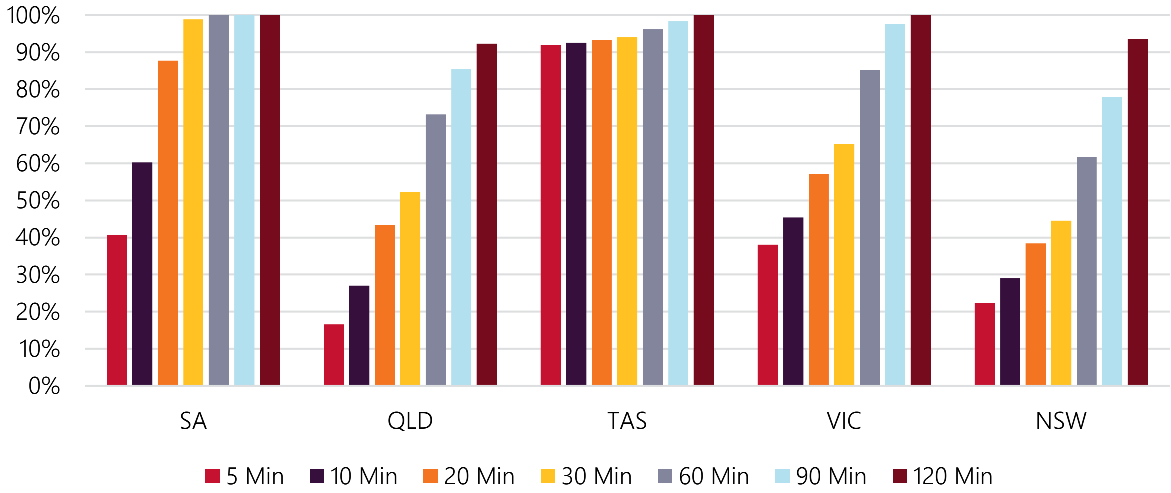

Figure 3 - Proportion of capacity realisable over various time horizons by NEM region, 2020

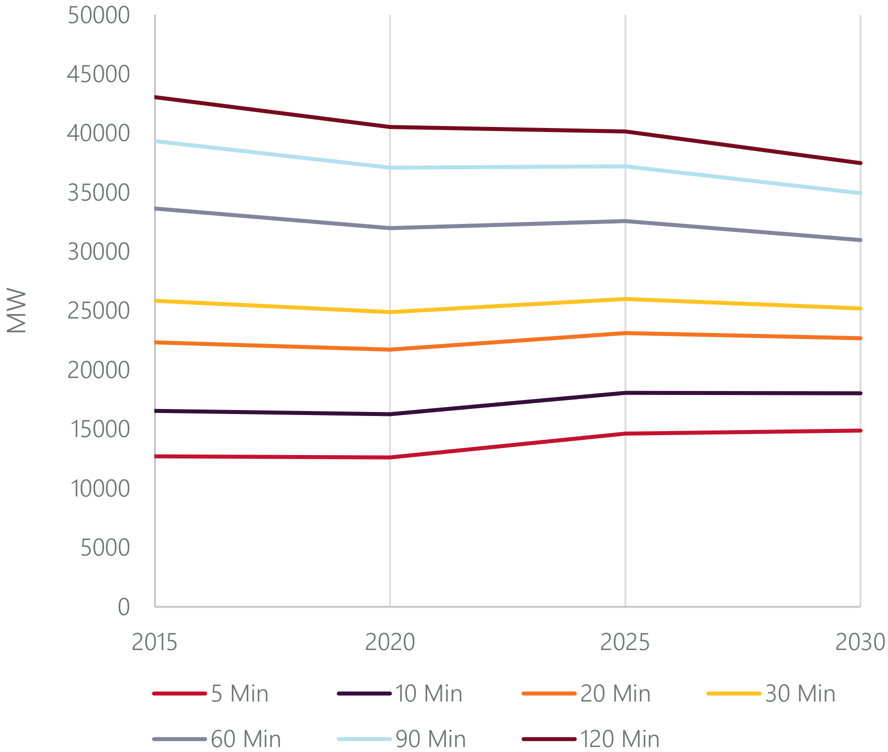

Figure 4 - NEM realisable ramp capacity at various time horizons; 2015, 2020, 2025, 2030

Figure 4 shows that ramp capacity realisable over longer time horizons is trending downwards. This reflects the ongoing retirements of scheduled generators. In contrast, ramp capacity realisable over shorter time horizons is trending upwards, reflecting the relative flexibility of new-build dispatchable generation. Despite being of lower aggregate capacity, this generation can deliver greater levels of reserves over short timeframes. These trends should, however, be viewed in light of the assumptions listed above the figure, which tend to optimistically portray the NEM's ramping capability. Further points of relevance not captured by Figure 4 include:

- There is a regional dimension to trends in realisable capacity. For example, New South Wales has the strongest upward trend of any region, due largely to Snowy 2.0. In contrast, South Australia had a strong downward trend due to the expected retirement of Osborne and Torrens Island Power Stations.
- The effective level of ramp capacity would be greatly increased by VRE pre-curtailment. VRE penetrations are expected to increase significantly, so the inclusion of semi-scheduled generation would dramatically change the trends shown in Figure 3.
- Some plant is much more likely than others to provide operating reserve. For example, plant with a higher generation cost and lower capacity factor typically leave more headroom than those that run continuously at or near their maximum output. Therefore, though useful, assessments based only on total system capacity do not reveal the full extent of trends in the provision of operating reserve. The true availability of operating reserve at any one time depends on the technical characteristics, network conditions and commercial incentives that affect the specific units with unutilised headroom.

To summarise this section, trends in the supply of operating reserve depend on location, delivery timeframe and the state of the power system at a specific point in time. Though these nuances are important, the NEM-wide trend is that the need for an operating reserve product appears to be influenced less by the supply of flexible ramp capacity (under the assumptions above) than it is by increasing uncertainty and variability. The latter will be the focus of the following sub-section.

<u>Demand for operating reserves</u>

The power system must be able to ramp up and down to meet changes in net demand over all necessary timeframes, accounting for variability[20] and uncertainty[21].

As discussed in response to question 2(i), the current energy market framework can be expected to drive participants towards meeting net demand ramps to the extent they are accurately forecast by market participants and AEMO. It is less likely that the energy market will meet changes in net demand that are not accurately forecast.

In this context, net demand uncertainty can be viewed as the key driver of the need to explicitly value operating reserves through a market product. However, as the ramping capacity used to meet expected variability cannot be separated from that which meets unexpected variability, then the greater the expected variability, the lower the surplus flexibility available in the fleet to meet any unexpected changes in net demand. For example, suppose a large, but accurately forecast increase in underlying demand[22] occurred in the middle of a day, and an unexpected

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[20] The overall size and rate of net demand ramps

[21] The level of net demand forecast error

[22] Consistent with the RIS, in the context of this report, underlying demand means: all electricity demand that is met by local scheduled, semi-scheduled, non-scheduled generation and distributed solar PV generation, and by interconnector imports to the region.

cloud passed over an area of high rooftop solar penetration at the same time. In this case, the amount of ramping capacity available to compensate for the loss of rooftop solar generation would be reduced by the amount of capacity being allocated to meet the increase in underlying demand. Note that this example demonstrates the substitutability of capacity used to address expected and unexpected factors because the impact on net demand from each was in the same direction at the same time. In general, the interaction of expected and unexpected variability is not this straightforward. Nonetheless, both factors are contributors to the need for an operating reserve market.

The RIS observed and projected significant increases in the variability of VRE over various timeframes. For example, Figure 4 captures 1-hour VRE ramps.

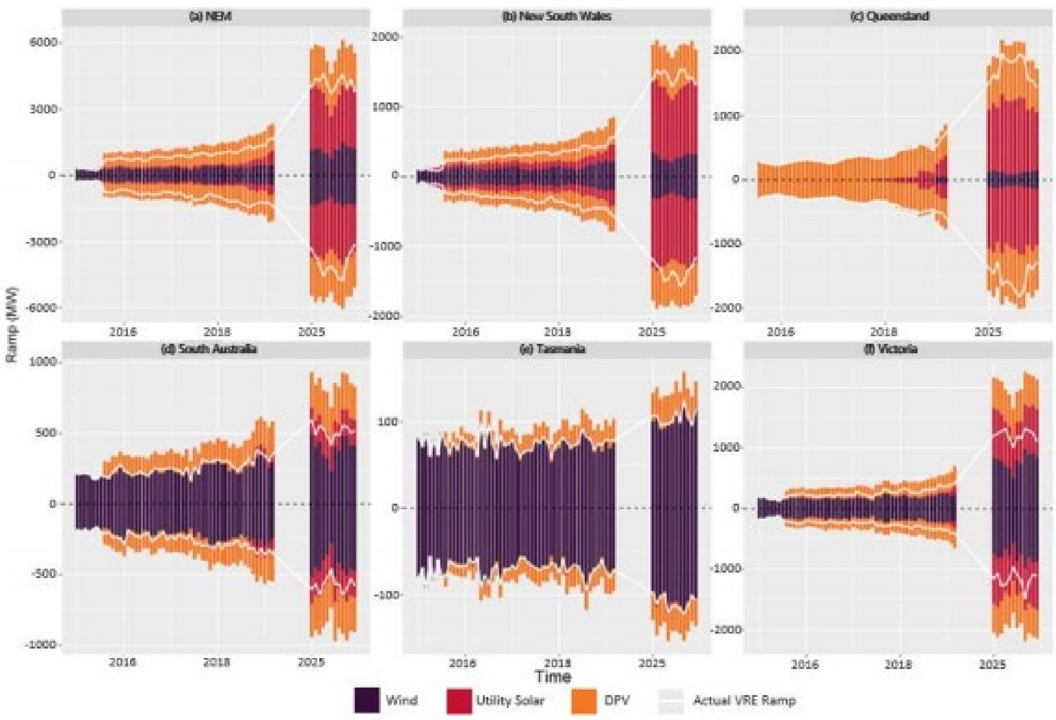

Figure 5 - NEM monthly top 1% of largest hourly ramps in VRE, actual 2015-19 and projected in 2025 under Draft 2020 ISP Central generation build

The RIS also observed and projected increases in net demand variability, largely as a result of increased VRE penetration. This is shown in Table 2. The table also shows that the growth in net demand ramps is not proportional to forecast growth in the ramps of its constituent elements, as all elements do not necessarily experience their maximum ramp simultaneously.

	Maximum upward ramp (MW)					Maximum downward ramp (MW)				
	Underlying demand	Wind	Utility solar	DPV	Net demand	Underlying demand	Wind	Utility solar	DPV	Net demand
2015	2,871	843	94	710	4,189	-1,731	-590	-98	-693	-2,196
2016	2,998	634	111	825	4,062	-2,106	-582	-106	-944	-2,290
2017	3,209	873	145	977	4,043	-2,096	-573	-150	-1,010	-3,020
2018	3,661	911	635	1,238	4,240	-1,960	-685	-612	-1,247	-2,402
2025	3,292	2,313	3,014	2,214	6,147	-2,145	-2,339	-3,129	-2,312	-4,682

Table 1 – 1-hour net demand ramps and constituent elements

Finally, the RIS highlighted expectations of increased net demand uncertainty due to increased VRE penetration. Though substantial improvements in weather and VRE-specific forecasting techniques have occurred in recent years, these improvements have not offset the impact of the growth in VRE. Figure 6 and Figure 7 show that the distribution of NEM net demand forecast error is widening in MW terms, while the distribution of constituent elements such as semi-scheduled error has tightened over the same period.

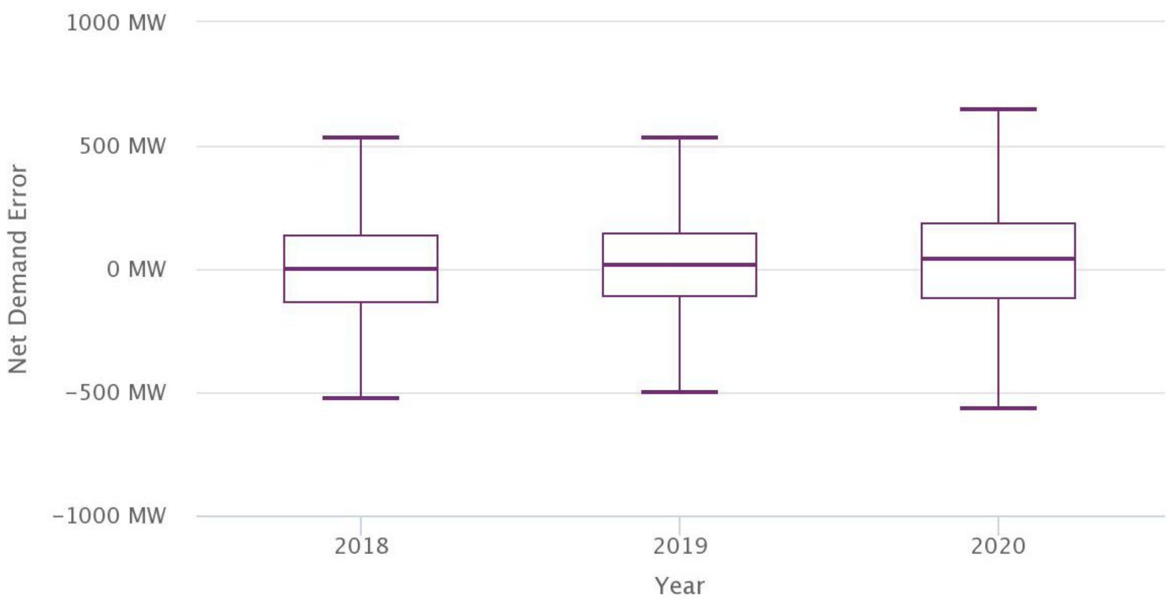

Figure 6 - NEM net demand forecast error distribution: 1 hour ahead

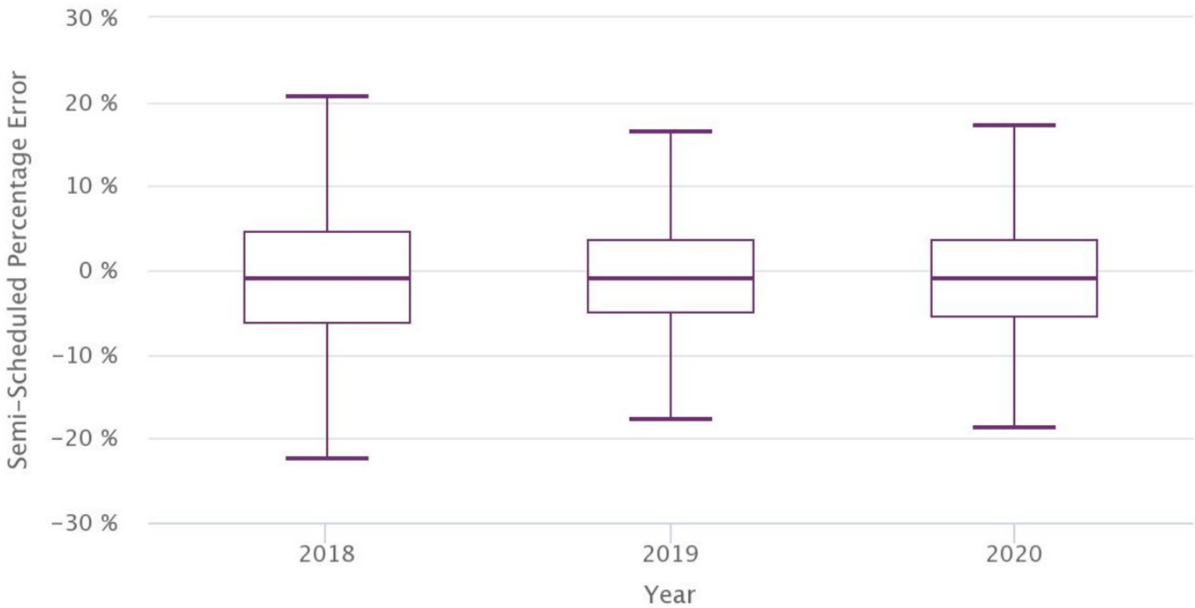

Figure 7 - NEM semi-scheduled generation percentage error: 1 hour ahead

QUESTION 2: OPTIONS TO ADDRESS VARIABILITY AND UNCERTAINTY OF NET DEMAND

(i) **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?**

With the expected increase in uncertainty and changing composition of the generation fleet, AEMO expects incremental improvements to current arrangements will not sufficiently negate the need to implement a new reserve service market. AEMO considers the incremental improvements included in the directions paper as separate improvements, not substitutes to a reserve product.

AEMO generally supports these initiatives, however, as they will help guide participants towards efficient decision-making under conditions of uncertainty in the context of the provision of existing services. AEMO notes that it is continually improving its forecasts and refining the information it publishes to the market. We also note the following specific items:

- AEMO is developing the *NEM power system design and engineering framework*[23], which will track and build upon the recommendations from RIS stage 1
- AEMO and TNSPs participate in the power system security working group, whose work includes broad consideration of contingencies and reclassification frameworks
- The ST PASA replacement project is underway, as discussed in responses to question 1(i)

None of the improvements noted in the directions paper or listed above target the fundamental need that an operating reserve market seeks to address i.e. to incentivise the provision of ramping capacity to a level that addresses net demand uncertainty.

Whilst AEMO cannot speak for participants' motivations, AEMO has a concern that they may provide reserves to a level derived from estimates (mean, mode) of market outcomes, and whilst it is expected they would adjust to a future with larger unexpected changes in net demand, this will only be to the extent that these changes impact expected revenue from existing markets.

Without an explicit value placed on ramping capacity there is no assurance this capacity will be provided to a level that is in the interests of consumers. If an ORDC (refer to appendix) appropriately captures these interests, specifically by incorporating the value of customer reliability and supporting an intervention framework that reduces the chances of supply interruption, then a reserve product can provide this assurance. Though it may be argued that participants will respond to greater uncertainty by providing the necessary reserves as a "free" by-product of the energy market, AEMO considers that the costs of this eventuality should be weighed against potential cost of the ramping reserve shortages that may occur if participants

23 https://aemo.com.au/initiatives/major-programs/engineering-framework

do not respond in this way. This reflects the general comments made in the response to question 1(ii).

AEMO will comment briefly on the incremental improvements not yet mentioned in this section:

- *Integrating emerging flexible resources*. AEMO considers that unlocking demand response resources is a key avenue through which power system flexibility can be enhanced. Projections of demand side participation (DSP) suggested by the ISP (and reflected in Figure 3 for the central scenario) are that the uptake will not be sufficient to materially affect the trajectory of NEM ramping capacity. AEMO notes the opportunity that an operating reserve procurement mechanism would provide to emerging flexible resources, including those participating in the wholesale demand response mechanism (WDRM). AEMO advocates for detailed consideration of how to make the WDRM and an operating procurement mechanism compatible.
- *Adapting system definitions*. The following changes would directly impact when AEMO intervenes in the market:
    - Updates to definitions and frameworks linked to credible contingencies, for example those associated with indistinct and protected events
    - Updating the basis for intervention to probabilistic thresholds as is proposed in the ST PASA redevelopment project

  However, neither of the proposals above places explicit market value on the provision of reserves to a level that matches the relevant intervention thresholds. Therefore, there is no assurance that this level of reserves is provided.

(ii) **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?**

AEMO considers that the co-optimised availability market is the most preferable to address the issues raised in the directions paper for the following reasons.

Firstly, the mechanism does not rely on an explicit trigger separate to dispatch of the energy market. This makes the co-optimised availability market preferable to callable operating reserve market and the ramping commitment market.

In contrast to reserves, FCAS is an intra-dispatch-interval (DI) process and has a level of technical sophistication around enablement, activation and compliance aligned with a framework that addresses a specific security need[24]. The process of converting reserves to energy, however, occurs across multiple DIs and needs no technical specification beyond that applied to the energy market. AEMO considers the fact that the co-optimised availability market can leverage the existing dispatch process to be an advantage over the callable operating

24 For details, see the market ancillary services specification (MASS): https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/market-ancillary-services-specification-and-fcas-verification-tool

reserve market and the ramping commitment market in regard to both implementation and operation of the service.

Further, with the 'activation' of reserves occurring through energy market dispatch, the co-optimised availability market retains the flexibility of participants in DIs between procurement and delivery. In contrast, the callable operating reserve market and ramping commitment market do not allow procured headroom to be utilised by the market in this interim period. Though these options may address concerns about operating reserves, they may do so with a relatively high impact on other markets.

Secondly, there are some key advantages to a 30-minute time horizon product compared to a 5-minute product. Description of these advantages and discussion of the possibility of a time horizon longer than 30-minutes is the focus of the remainder of this section. On this basis, AEMO prefers the co-optimised availability market to the co-optimised operating reserve market.

AEMO acknowledges that the question of total cost impact on consumers of an operating reserve market is a complex empirical question, dependent on how the supply and demand of operating reserves scale across different time horizons. However, AEMO considers that a 5-minute operating reserve product may be high cost for the following reasons.

Firstly, the level of reserves that are realisable over a 5-minute timeframe is significantly less than those realisable over a 30-minute timeframe. This is captured, in aggregate, by Figure 3. However, AEMO notes that realisable ramping capacity is a function of the specific units online at any one time. Figure 5 shows a specific historical example of the ramping reserves provided as a by-product of energy dispatch; the Queensland region at the 19:00 DI on 6 March 2020. Please note the following context is reflected in Figure 5:

- Interconnectors were binding in import to Queensland, so no ramping capacity was available from NSW units
- Mt Stuart units and Wivenhoe unit 1 were both offline at the start of the DI, meaning they would take 18 and 3 minutes respectively to synchronise, according to their fast-start-inflexibility profiles
- The effects of intra-regional constraints in realising the reserve capacity as energy at any particular network location (e.g. the regional reference node) have not been modelled

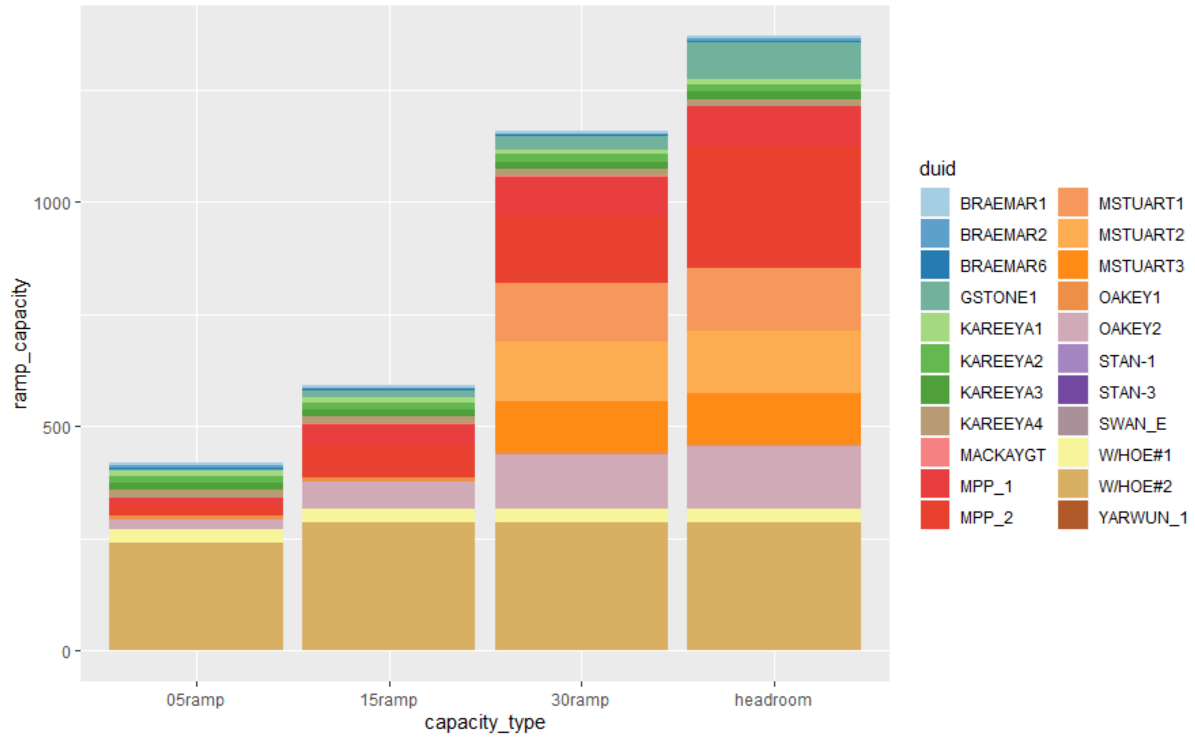

Figure 8 - Qld, 19:00 DI 6 March 2020, Realisable headroom across time horizons (MW)

The DI analysed in Figure 7 was chosen because reserves are low, but not low enough to trigger any forecast LOR declarations. The largest credible risk in Queensland was 587MW and the LOR reserve was 1358MW (closely corresponds to the far-right column in Figure 7 i.e. the sum of Queensland headroom, unconstrained by ramp time horizon). Of note is that, though the loss of the largest credible risk could comfortably have been covered using available headroom over 30 minutes, it could not have been covered in 5 minutes

More generally, Figure 8 demonstrates two things:

- There are times when realisable ramp capacity can scale down sharply between 30 and 5 minutes
- Even in a region of relatively low flexibility like Queensland (Figure 3), there are times when a high proportion of total headroom can be realised over 30 minutes

If the sole purpose of an operating reserve market was to provide a level of operating reserve that addresses net demand uncertainty, then it could be argued that the reduction in realisable ramp capacity as time horizon shortens is only an issue to the extent that forecast uncertainty does not proportionately reduce on shorter time horizons as well. However, as emphasised throughout this submission, one of the key objectives of an operating reserve service is to reduce the need for AEMO intervention. Therefore, under current frameworks, and as reflected in the ORDC in the appendix, any operating reserve service should as a minimum procure to the fixed level corresponding to the intervention threshold. Mandating that this fixed level be procured over 5 minutes reduces the realisable ramp capacity, effectively inducing scarcity and adding cost. A 5-minute time horizon may effectively preclude certain resource-types from participating in the market, including offline generators or demand response providers.

AEMO's power system security obligations only require a return of the system to a secure state within 30-minutes and therefore AEMO considers that this full-time horizon should be utilised to minimise cost impact on consumers and allow a broader range of participation.

There are also advantages to a reserve product with a time-horizon greater than 30-minutes. As reserve procurement and obligations under the co-optimised availability market are rolling on a 5-minute basis, then such a product still provides assurance that sufficient reserves are available. Where a product's timeframe is longer than the interval between the latest time to intervene and the intervention itself, then AEMO has assurance that resources procured in the reserve market are obliged to provide their response. Where a product's timeframe is shorter than the intervention lead time, then AEMO must make its intervention decisions on the basis of pre-dispatch projections of reserve procurement.

AEMO notes, firstly, that intervention decisions are currently made on the basis of pre-dispatch assessments of reserves, so such an outcome is still workable. Secondly, AEMO considers that designing a product of time horizon long enough to exceed any possible intervention lead time would be an extreme approach. However, AEMO includes these points to provide insight into the complexity of correctly choosing a product time horizon. Drawbacks of a longer time horizon product include:

- Net demand uncertainty generally continues to grow over a much longer time horizon than ramp capacity. For example, in the case shown in Figure 5, minimal additional headroom is realised by extending the time horizon beyond 30 minutes. In contrast, the FUM over a 30-minute horizon is a small fraction of the FUM at a 12-hour time horizon.
- The 'expected' component of a net demand ramp has the potential to be larger over longer timeframes, requiring greater reserve procurement and therefore higher cost.

Appendix – Operating Reserve Demand Curve (ORDC)

AEMO proposes that an ORDC reflects the two main objectives of the operating reserve service. As stated, these are:

(a) Ensure enough reserves are available and physically realisable to allow the generating (and demand response) fleet to meet changes in net demand, accounting for the uncertainty in these changes; and

(b) Minimise the need for the system operator to intervene as a result of uncertainty and variability in supply and demand to ensure power system security and reliability

Each of points (a) and (b) above imply a section of the ORDC. The resultant curve is similar in principle to that proposed by Hogan and Pope for the PJM power system[25]. This section briefly covers each component of the ORDC separately and then in combination.

To address objective (a), AEMO proposes to derive a curve from a calculation of the probability of lost load (POLL) at various levels of reserves. As a simplistic example, if reserves in a region are expected to be 300MW and there is a 20% probability that actual net demand will exceed forecast net demand by 300MW, then there is effectively a 20% chance of lost load. In principle, consumers would be willing to pay 20% of the value of lost load (or value of customer reliability (VCR)[26]) for the 300th MW of reserves.

With the POLL decreasing as expected reserves increase, a continuous, downward sloping demand curve of the type shown in Figure 9 is formed. This curve will result in reserve procurement up to the level at which the incremental cost of provision by generation and demand response resources exceeds the incremental benefit to consumers. Note, the curve is not proposed to exceed the market price cap (MPC) and Q* is the quantity of reserves for which VCR*POLL = MPC.

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25 *PJM Reserve Markets: Operating Reserve Demand Curve Enhancements.* https://scholar.harvard.edu/whogan/files/hogan_pope_pjm_report_032119.pdf, p 35

26 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability

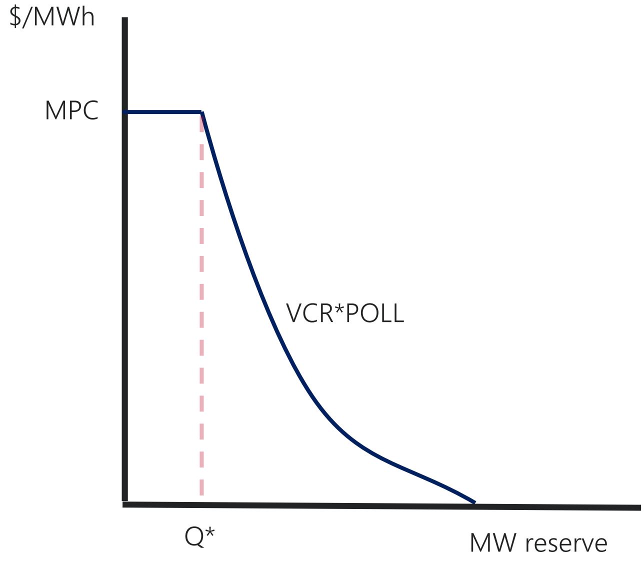

Figure 9 - ORDC component addressing net demand forecast uncertainty

To address objective (b), AEMO proposes a curve which procures a fixed level of reserves corresponding to the intervention threshold. Under current frameworks, this is the LOR2 trigger, either set by the largest credible risk or the FUM. Under a future ST PASA, this is the reserve deficit at the confidence level chosen for intervention. Q^ denotes this fixed level of reserves in Figure 10.

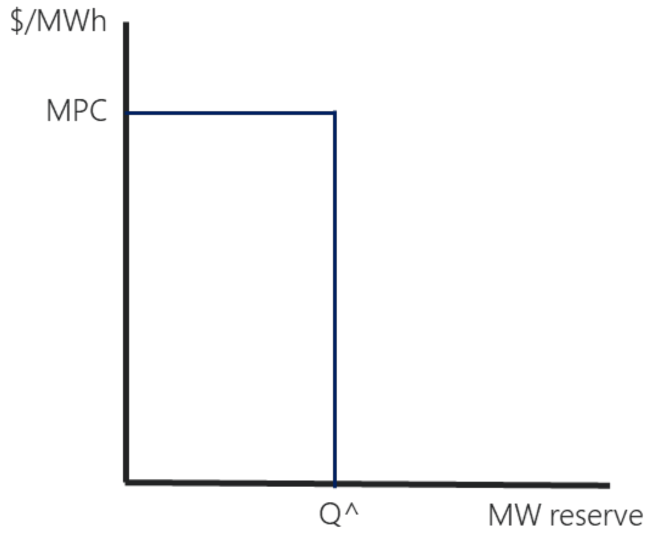

Figure 10 - ORDC component addressing intervention framework

AEMO proposes to combine the two components as shown in Figure 11. This implies headroom can be used to address either objective (a) or (b). The demand curve does not strictly cover the case of a large net demand forecast error occurring at the same time as the largest credible contingency. AEMO considers that this possibility is too remote to justify the costs of procuring a level of reserves that could satisfy objectives (a) and (b) simultaneously. Please note that AEMO proposes that the procurement of headroom in the operating reserve market should not undermine any existing security frameworks, and therefore headroom cannot simultaneously be used as FCAS.

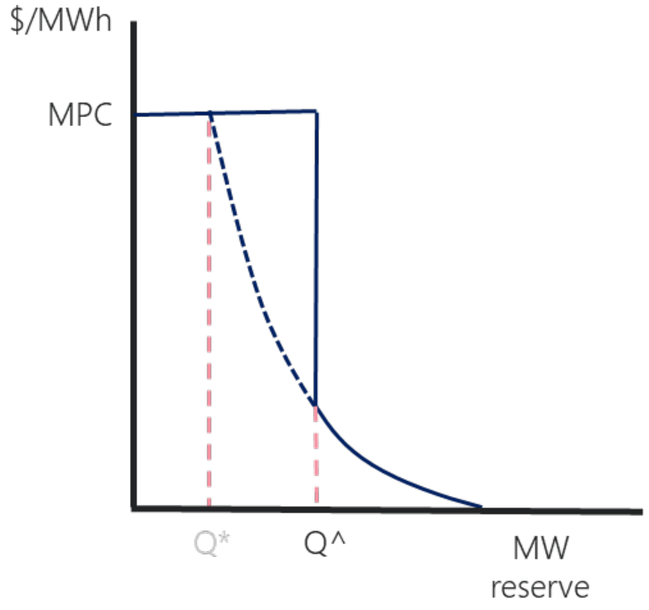

Figure 11 - ORDC addressing both key objectives of operating reserve service

There are many detailed design questions to be addressed in relation to the formulation of the ORDC in Figure 11, including:

- As the price in the reserve market can reach MPC, what is the interaction of this market with the existing reliability settings?
- Should forced outage rates of scheduled plant, which are currently factored into the FUM, be included in the reserve uncertainty calculation if the worst-case scenario contingency is satisfied by the fixed section of the demand curve?
- How would the participation of VRE in the reserve market impact the treatment of VRE in the uncertainty calculation?
- How do changes to the reserve framework proposed in the ST PASA redevelopment project impact any of the issues raised above?
- How will a redeveloped ST PASA combine a regional market for operating reserves with a nodal assessment of reserve adequacy?