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Australian Renewable Energy Agency

ARENA

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System Services Rule Changes
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ARENA submission to System Services Rule Changes Consultation

This submission provides background information and insights from projects funded by the Australian Renewable Energy Agency (ARENA) as relevant to the AEMC's current rule change consultation process.

In summary -

- **Two-sided market** - The 2020 Integrated System Plan indicates that rooftop PV capacity could be up to 35GW by 2035 (i.e. equivalent to current NEM peak demand). In capacity terms, distributed energy resources (DER) could outstrip large-scale investment across the all time-scales and this has implications across all aspects of the electricity system, including at the transmission level. In this context, many of the above issues will need to be addressed by transitioning to a more 2-sided market such that demand side participants have significantly greater incentives to contribute to power system security.
- **Principles for assessment** - As an extension to the AEMC's principles of 'technology neutrality' and 'flexibility', solutions should account for the capacity for system services to be provided at various system levels (i.e. transmission scale, through to DER). While this may seem implicit there are indications of some siloing between current system services and DER reform agendas. This is evidenced by the current consultation paper being silent on the implications of DER for future system security challenges or solutions.
- **Fast frequency response** - ARENA supports consideration as to how appropriate incentives for fast frequency response (FFR) can be developed. This should reflect the capacity of batteries and other inverter-based generation to provide primary regulating and contingency frequency response as well as inertia-like response. It should also reflect the urgent need for incentives to encourage targeted responses (from generation

and load) during major events in light of the issues with the current Under Frequency Load Shedding Scheme identified by AEMO.

- **Operating Reserves Market** - The proposal for a 'scarcity price adder' (as being considered by the ESB Post-2025 Review) has the advantage of allowing all costs to be kept 'in-market'. This is important to provide symmetry in costs and risk exposure of supply and demand sides resources. Large-scale demand response and aggregated DER will play an increasingly important role in the transition to renewables. There are also potentially inconsistencies in sizing the operating reserve market with regard to a deterministic standard (e.g. N-2) while other market settings are based around a probabilistic reliability standard (i.e. 0.002% or 0.0006%).

- **Ramping service** - Studies have confirmed that increasing solar generation during the day can increase ramping costs in the evening. This can provide a very strong price signal for capacity to be available in the evening without the need for additional incentives. Should an additional incentive be created, it is important that it reflect the ability of the demand side to reduce the underlying requirement for ramping through load and generation shifting.

- **Capacity commitment mechanism** - ARENA notes that the availability of VRE and demand response can be highly sensitive to on-the-day conditions. ARENA is investing in a range of projects to improve same-day forecasting for solar and wind. We expect that information available to the market closer to real time will allow for much more reliable and efficient resource commitment than could be achieved a day ahead.

- **Synchronous services markets** - A priority for market reform is to ensure that all essential system services are appropriately incentivised (either through regulation or price signals). Innovations in power electronics are rapidly evolving and ARENA is supporting a range of trials that demonstrate how inverter-based generation might complement or substitute for synchronous generation, including in relation to the provision of inertia-like response and system strength.

- **Efficient management of system strength** - ARENA agrees that the current 'do no harm' framework does not support coordinated investment by generation and transmission. A number of ARENA studies have highlighted that substantial cost savings can be achieved through better-coordinated investment in synchronous condensers, and other remediation strategies, at different system levels. Reforms should ensure appropriate cost and risk allocation to drive lowest-cost solutions and provide transparency of costs for generators and consumers.

Further detail is provided in the attached Stakeholder Submissions Template.

About ARENA

The Australian Renewable Energy Agency (ARENA) was established in 2012 by the Australian Government. ARENA's function and objectives are set out in the *Australian Renewable Energy Agency Act 2011.*

ARENA provides financial assistance to support innovation and the commercialisation of renewable energy and enabling technologies by helping to overcome technical and commercial barriers. A key part of ARENA's role is to collect, store and disseminate knowledge gained from the projects and activities it supports for use by the wider industry and Australia’s energy market institutions.

Please contact Jon Sibley, Principal Policy Advisor (jon.sibley@arena.gov.au) if you would like to discuss any aspect of ARENA’s submission.

Yours sincerely

Darren Miller

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SUBMITTER DETAILS

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CHAPTER 1 – INTRODUCTION

Question 1: Section 1.2 & 1.3 – Current ESB & AEMO work relating to the rule change requests	
1) What are stakeholders' views on how the rule change processes should be integrated with ESB and AEMO work programs?	N/A
2) Are there any additional processes that should be closely considered by the Commission when progressing these rule change requests?	The current paper is silent on the manner in which DER will contribute to system reliability and security challenges and solutions. This is despite the 2020 Integrated System Plan indicating that rooftop PV capacity could be up to 35GW by 2035 (i.e equivalent to NEM peak demand). Electric vehicles (EVs) could constitute 12% of 'power point' demand. In capacity terms, DER could outstrip large-scale investment for the foreseeable future and this has implications across all aspects of the electricity system including at the transmission level.[1] Each of the rule changes currently under consideration should be explicitly assessed in the context of managing and facilitating greater demand side participation. This theme is further explored below in relation to the specific rule change proposals.
Question 2: Section 1.6 – Timetable for the consultation process	
1) Do stakeholders have any comments on the proposed timetable for the system services rule changes?	ARENA considers that changes to the 'do no harm' provisions for connecting large-scale generators are a priority and should be considered at the earliest opportunity. The benefits of reforms in this area are set out below and these could be explored under a regulatory sandbox in the first instance. ARENA considers that appropriate incentives for primary frequency response and/or fast frequency response (as per the respective rule change processes) should be implemented in advance of the sunset for mandatory requirements in 2023. The approach taken to primary frequency response

[1] https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en&hash=6BCC72F9535B8E5715216F8ECDB4451C

	(PFR) will have a significant bearing on what further reforms are required with regard to inertia, fast frequency response (FFR) and ramping services.

CHAPTER 3 – APPROACH

Question 3: Section 3.2 & 3.3 – Three work streams: dispatch, commitment and investment	
1) Do stakeholders agree with the AEMC's approach to grouping the rule changes, at least for initial consideration?	ARENA notes that Infigen's Operating Reserve Market proposal seeks to address contingency events that may require a response within a current dispatch interval and so it should be considered in concert with the PFR and FFR proposals.
2) Do stakeholders believe that Figure 3.1 captures the key issues to be considered for each rule change in each time frame?	N/A
3) Do stakeholders have views on whether/which services should be procured in certain time frames and not others?	N/A

CHAPTER 4 – ASSESSMENT FRAMEWORK

Question 4: Section 4.2 – The system services objective	
1) Do stakeholders agree with the AEMC's proposed system services objective being used to assess these rule changes? If not, how should it be amended or revised?	ARENA supports the AEMC's proposed system services objective and acknowledgement of the need to stimulate and make use of technology and commercial innovation over time. This is a significant challenge in the context of system strength and inertia services where new technology approaches are developing rapidly. In these situations the AEMC will need to counter status quo and loss aversion biases within industry. The efficacy of new solutions requires that system services be defined in a robust, discrete and technologically neutral manner and that barriers to the provision of a service are as low as possible. In cases where the need for action is ahead of the ability to define services in this way, interim measures should be targeted at addressing the immediate need and be set to sunset at an appropriate time, such as is being done with the PFR reforms.

Question 5: Section 4.3 – The planning, procuring, pricing and payment service design framework	
1) Do stakeholders agree with the '4Ps' service design framework being used to assess these rule changes?	Yes

Question 6: Section 4.4 – Principles for assessment	
1) Do stakeholders agree with the principles proposed for assessing the rule change requests? If not, should any principles be amended, excluded or added?	As an extension to the principles of 'technology neutrality' and 'flexibility', solutions should account for the capacity for system services to be provided at various system levels (i.e. transmission scale, through to DER). While this may seem implicit there are indications of some siloing between the system services and DER reform agendas. This is evidenced by the current consultation paper paying no regard to the implications of DER for future system security challenges or solutions. This is despite AEMO's Renewables Integration Study identifying DER as being at the centre of the system security challenge.[2]

CHAPTER 5 – THE RULE CHANGE REQUESTS

Question 7: Section 5.1 – Infigen – Fast frequency response ancillary service market	
1) What are stakeholders' views on the issues raised by Infigen in its rule change request, Fast frequency response market ancillary service?	ARENA and other industry trials are demonstrating that fast-acting inverter-based VRE and storage can support continued secure power system operation as synchronous plants retire. Infigen's FFR rule change focuses on the issue of declining inertia, which will become more critical over the coming decades. It is important to note however that contingency FCAS products, like that proposed, have inherent limitations as an inertia substitute. Firstly, they only respond outside of the Normal Operating Frequency Band (which adds a time delay to their response), and secondly, they are set to in relation to a frequency deadband rather than the Rate of Change of Frequency (RoCoF). Both of these limitations mean that a 2-second FFR market may incentivise services that are slower and potentially less useful than the services that modern inverter-based generators and storage are capable of providing. This leaves value from current assets unrealised and a residual gap in the service definition framework as thermal generators retire. While the introduction of a 2-second market could be a pragmatic initial response, it is important that the AEMC consider this in the context of the actual power system requirements for frequency support which exist on a continuum over time (millisecond to dispatch interval timescales). The extent to which incentives recognise, and work seamlessly across, this continuum will reduce boundary distortions (that can arise from the creation of multiple discrete services) and ultimately support the most economic outcome. Boundary distortions could be especially pronounced for deviation services (such as FCAS) where service delivery is measured as change in MW between two time intervals. Such

[2] https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris

	distortions could be lessened under a framework which incentivised a change in MW proportion to the extent of frequency deviation.
2) Do stakeholders agree with Infigen's view that a change to the NER is required to encourage efficient provision of FFR services in the NEM following contingency events?	ARENA projects demonstrate that current frequency control frameworks do not adequately reward fast frequency response from inverter-based generation. For example, through an ARENA -supported trial, Hornsdale Power Reserve 2 will demonstrate Tesla's Virtual Machine Mode that is able to deliver a precise response to RoCoF as an inertia-like product. We understand there is however no incentive for the provision of this service outside of the trial.
3) What are stakeholders' views on if there are any other issues or concerns in relation to frequency control in the NEM as levels of synchronous inertia decline?	Faster frequency response will also be relevant to managing the increasing variability of supply and demand side resources which can operate across a range of timescales. ARENA expects this will become increasingly challenging over time as more and more resources become subject to the risk of coincident behaviour. For example, this may include multiple GW of unscheduled/unregistered EVs responding to wholesale or retail price signals. As such, regard should be given to both demand and supply side variability with regard to positive incentives and cost recovery (causer pays) options. FFR may, in the not-too-distant future, be demonstrated as a meaningful substitute for physical inertia. Various trials (such as HPR2) are exploring the FFR capabilities of batteries in providing an inertial response (e.g. using the swing equation) within milliseconds. Because it will respond to RoCoF, it is expected to commence a frequency response within the Normal Operating Frequency Band (NOFB) and therefore faster than contingency services. Demand response has also demonstrated its ability to provide a very fast response although this is not expected to be able to be proportional to RoCoF in most cases. There are a number of international studies that point to how frequency stability can be maintained in the transition to 100% inverter-based generation.[3]
4) Do stakeholders consider there are alternative solutions that could be considered to improve the frequency control arrangements in the NEM for managing the risk of contingency events as the power system transforms?	The underlying requirement for frequency management is a proportional and timely frequency-watt response that operates on a continuum over time and over the frequency band. Over time, this covers primary, secondary and tertiary responses. Over the frequency band, this includes regulating, contingency and under- and over-frequency protection schemes. The ability of inverter-based generation and storage to provide an accurate and sustained outcome across all time-scales may provide the opportunity to greatly simplify service categories. This could

[3] E.g. http://ipu.msu.edu/wp-content/uploads/2018/01/IEEE-Achieving-a-100-Renewable-Grid-2017.pdf

	include through the development of real-time incentives for PFR that support a continuous response over time and proportionate to the extent of frequency deviation (or RoCoF). In particular, reforms to the incentives for contingency products should be considered in relation to the need for appropriate incentives for inertia, PFR and Under Frequency Load Shedding (UFLS). ARENA's submission to the DER Technical Standards Rule Change sets out how an incentives framework could support UFLS as the effectiveness of the current scheme degrades over time (due to low minimum demand).[4] Retail contracts are starting to develop to include load shedding provisions targeted at specific loads and in the future this may extend to occasionally shedding willing customers (Rules permitting). This will be more economically efficient and fair than current 'rotational load shedding' arrangements and should be considered as part of the AEMC's broader consideration of incentives arrangements for frequency control.
5) Do stakeholders consider that 5-minute markets for FFR ancillary services likely to be effective and efficient in the global interconnected NEM and on a regional basis?	N/A
6) Do stakeholders consider Infigen's proposal will provide adequate pricing signals to drive efficient investment in FFR capability in the NEM?	As above
7) What are stakeholders' views on, if introduced, how the costs associated with any new FFR market ancillary services should be allocated?	It is efficient that costs be recovered consistent with the principle of causer pays. This could extend to loads *where its operation could have a material impact on system frequency*, including some aggregator categories. DER should also be provided with the opportunity to provide services subject to meeting reasonable service delivery requirements. It would be beneficial for revenues from FFR service provision and costs associated with causer pays liabilities to be transparent and symmetrical as this would allow causers to effectively hedge their costs both through physical and financial means (i.e. by building a battery or striking a hedge with a FFR service provider). A liquid hedge contract market would make investments in FFR capable resources more bankable.
8) What do stakeholders consider to be the likely costs associated with establishing two new ancillary service markets for FFR in the NEM?	N/A

[4] https://www.aemc.gov.au/rule-changes/[...]minimum technical standards for DER.

9) What are stakeholders' views on how the proposed solution may result in any substantial adverse or unintended consequences in the NEM?	N/A
10) Are there specific issues with FFR that stakeholders think should be addressed in the NER as part of the establishment of markets for FFR services?	N/A
Question 8: Section 5.2 – Infigen – Operating reserves market	
1) Do stakeholders agree with Infigen that tight capacity conditions and increasing uncertainty in market outcomes are problems that an operating reserve would address?	The AER's wholesale energy market report for Q1 2020[5] indicates that, in that quarter, the NEM experienced the highest number of Lack of Reserve 2 (LOR 2) hours in the last four years. Nearly half of these were not forecast in pre-dispatch. They resulted from unplanned extreme events such as the bushfires around the Snowy region and the unexpected loss of the Heywood interconnector in January. Infigen's proposal highlights the need for enhanced operating reserves to respond to 'new modes of failure' and to '*provide AEMO with the flexibility to respond to real-time variability*' (p.10). This implies that resources in the reserve would respond within a 5-minute dispatch interval, either autonomously (in response to locally measured frequency, like contingency FCAS) or in response to AGC signals (like regulating FCAS). The only differences between the operating reserve and FCAS services appears to be: ● its 'aheadness' (Infigen proposes commitment 30 minutes ahead) and ● the response time of participating units. Infigen further states that operating reserves would '*not necessarily need to respond in such tight timeframes [as FCAS] – imposing unnecessarily fast response times on Operating Reserves would reduce the available supply stock.*' It is therefore not clear how well this would guard against the unexpected events that are cited in the proposal. It seems important to be specific about what types of contingencies different operating reserve markets could address and the residual gaps that leaves for enhanced primary (regulating or contingency) frequency response. Through its forward investment pipeline, ARENA observes a range of business cases for new plant investment including battery storage. There is wide variability in assumptions about the value of spot market volatility. Often batteries will assume a daily cycle of low value arbitrage and use a cap contract value as a proxy for peak price earnings. It's possible that a centrally procured slow reserve market could provide a more bankable revenue stream than the current spot market for some generators. It is not clear however whether batteries would be sufficiently valued in a slow market. In committing to a

[5] https://www.aer.gov.au/system/files/Wholesale%20Markets%20Quarterly%20Q1%202020_0.pdf

	reserve service 30 minutes ahead, a battery would also need to consider the opportunity cost of potentially missing out on a peak price event which they otherwise would be well placed to capture. Overall, it is not clear how material this would be, as a driver for new investment, compared to the signals already provided by the spot and contract markets.
2) Are there alternative solutions that could be considered to address tight capacity conditions and increasing uncertainty in market outcomes?	The move to a two-side market should provide incentives for aggregators (such as retailers) to manage demand side variability and procure balancing resources as either physical or financial hedges (i.e. within their demand portfolio or across the market). This can be expected to increase overall operating reserve margins that specifically target demand side variability to an efficient level. As noted above, demand side will be an increasingly important 'mode of failure' in the NEM. Various studies have shown that demand side flexibility can substantially reduce the requirement for investment in balancing resources (such as peaking plant, storage and transmission capacity) in the transition to renewables.[6] The ARENA-AEMO demand response trial indicates that demand response could offer a significant source of operating reserve under a two-sided market framework. It demonstrates that lots of options exist across different market segments including behavioural demand response from residential customers, albeit with longer lead times and less precise control. Electricity retailers are developing a range of demand response products that may not qualify to participate in a central commitment because of technical performance and baselining issues. A flexible, decentralised approach to demand-side resource commitment, like a two-sided market, may therefore encourage broader demand side participation, than a central commitment approach.
3) Do stakeholders consider Infigen's proposal would provide adequate pricing signals to drive efficient use of and investment in operating reserve services now and in the future?	ARENA notes that the Retailer Reliability Obligation was specifically designed by the ESB to address resource adequacy issues in the NEM. Operating reserves and scarcity price adders are also among the range of resource adequacy mechanisms being considered under the ESB post-2025 Review. ESB consultations however indicate that the 'missing money' issue, that the Infigen proposal seeks to address, may be a second-order issue for investors looking to develop new dispatchable capacity, compared to long term policy certainty.
4) How do stakeholders think that separate operating reserves arrangements would affect available capacity in the spot, contracts and FCAS markets now and in the future?	N/A

[6] E.g. https://www.sciencedirect.com/science/article/pii/S0014292118301107 and https://www.sciencedirect.com/science/article/abs/pii/S0360544220303121

5) How do stakeholders think separate operating reserves arrangements would affect prices in the spot, contracts and FCAS markets now and in the future?	Withdrawing operating reserve capacity from the energy and FCAS markets would uplift wholesale prices during LOR events regardless of whether that capacity was called on or not. Whether or not this price uplift is offset by increased supply of new capacity will depend on a range of factors in the overall investment environment. ARENA notes that the cost of new capacity developed under the RERT demand-response trial were based on the long run costs including customer recruitment and set up costs. These costs were recovered principally through contract payment by ARENA. Payments from AEMO for activation under the RERT were generally not considered bankable by participants and formed a minor proportion of overall revenues. Further, there are indications that, once established, some proponents would prefer to utilise this capacity in the spot market due to the better revenue opportunities.
6) How could the design of an operating reserve market (e.g. criteria for eligible capacity) best support competitive outcomes both in the operating reserves market but also energy and FCAS markets?	See the response to 8.2 above.
7) What are the factors that should be considered when seeking to set and procure efficient levels of operating reserve?	ARENA notes that there are potential inconsistencies in sizing the operating reserve market with regard to a deterministic standard (e.g. N-2) as used to define Lack of Reserve events, while other market settings are based around a probabilistic reliability standard (i.e. 0.002% or 0.0006%).
8) Would Infigen's proposed operating reserve market result in any substantial adverse or unintended consequences in the NEM?	N/A
9) What are the costs associated with establishing an operating reserve market in the NEM? If introduced, how should these costs be allocated?	See the response to 8.2 above. FCAS 'causer pays' arrangements provide a degree of symmetry in costs and benefits between the causers and the solvers of frequency imbalance (leaving aside the significant limitations of current arrangements). It is not clear how the costs for payments under an operating reserve market are proposed to be recovered and there does not appear to be a natural counterparty as there is under causer pays. Increasing market fees to fund an operating reserve market introduces public good spill-overs and dilutes incentives for spot market participation. We encourage the AEMC to consider whether it is more efficient to recover the costs through a dynamic price adder (as being considered by the ESB) that is transparent to participants ahead of pre-dispatch. This would ensure that additional costs only accumulate to parties that are not sufficiently hedged during peak times and supports incentives for in-market participation by generation and demand response units.

	The joint ARENA and AEMO submission to the demand response mechanism rule change[7] provides a high level assessment of the pricing of RERT participants of demand response trial participants. Due to high establishment costs for demand response compared to the marginal cost of service delivery, we should expect investment in new capacity to be sensitive to any uncertainty around future pricing, especially if long-term contracting opportunities are not provided. An operating reserve market would not appear to provide long term contracting opportunities compared to normal spot market operation, the RERT or a price adder (where costs remain in-market).
10) What kind of incentive/penalty arrangements would be necessary to be confident the operating reserves procured are available when needed?	N/A
Question 9: Section 5.3 – Delta Electricity – Introduction of ramping services	
1) Do stakeholders agree with Delta that price volatility that occurs when dispatchable generators ramp through their energy bid stacks in response to predictable, daily, high rates of change from solar ramping up and down is a problem that needs addressing?	Jha and Lesie (2020)[8] demonstrate how increasing solar generation leads to increasing evening power costs. This is found to be mostly the product of an exercise in market power during ramping periods rather than an increase in the marginal cost of generation at those times (i.e. it therefore effectively a scarcity price signal). This provides market opportunities for generators or storage that can start up or ramp up more quickly or at lower cost. As solar continues to grow, it is important that the market is able to appropriately value these ramping services and provide, overall, a supportive investment environment for new dispatchable capacity including demand response. The authors conclude that forward (e.g. day ahead) commitment of resources can help suppress peak pricing however, forward commitment would also reduce the flexibility of resources to respond to on-the-day conditions that may be the major determinants of ramping requirements. This could result in less efficient dispatch outcomes than provided by current arrangements. ARENA-supported initiatives such as Renewable Energy Hub[9] are demonstrating how the contract market can adapt to increasing daily price spreads through the introduction of it's 'super peak' product which provides coverage for retailers during morning and evening ramp periods. Currently backed by hydro,[10] ARENA expects that products such as this could provide more bankable revenues for batteries and potentially demand response. Renewable Energy Hub's 'virtual storage' swap product also allows retailers to on-sell a midday 'long position' (resulting from increasing customer solar) to energy storage providers to charge during the day at a more stable price. Retailers then buy-back that energy during

[7] https://www.aemc.gov.au/sites/default/files/2018-05/ARENA-AEMO%20joint%20submission.pdf
[8] https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3603627
[9] https://arena.gov.au/projects/renewable-energy-hub-marketplace/
[10] https://www.energymagazine.com.au/renewable-energy-hub-snowy-hydro-sign-super-peak-energy-deal/

	the high priced periods of the day. The combined effect of these innovative products, over time, will be to mitigate requirements for ramping while stimulating increased ramping capacity in the market. The 2020 ISP forecasts that up to 35GW of rooftop solar could be installed by 2035. As such, much of the solar that will contribute to these higher ramping requirements will be at customer premises and not scheduled in the market. Under current tariff arrangements, retailers will pass on higher market costs to their customers that maintain high demand throughout the event rather than those that are contributing to the high rate of change. This suggests that there is a case to enhance incentives for the demand side to contribute more to ramping requirements by moving to a two-sided market and/or by allowing the demand side to provide ramping services such as is being proposed by Delta Electricity. At a minimum, more cost reflective retail pricing (or controlled load contracts achieving similar outcomes) will be essential in shifting demand from high-cost evening, to low-cost daytime periods. For this to be effective, tariff blocks will need to have relatively short durations e.g. hourly, as opposed to peak, shoulder, off-peak, and be more symmetrical for net customer load and generation. Smart meters and the pass-through of more cost-reflective retail tariffs will be essential to achieving an efficient level of demand side participation. While ARENA is supporting the development and demonstration of a number of next generation retail products, we also observe significant frustration from stakeholders at the slow pace of the roll-out of smart meters which increases the cost of acquiring customers into retailer or third-party demand response programs.
2) Do stakeholders think that a new raise and lower 30-minute FCAS would address the price volatility at these times? Are there alternatives that could be considered to address this problem?	See 9.1 with regard to market power effects.
3) Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in ramping services than existing price signals and information provided through the PASA and pre-dispatch processes?	See 9.1 - Adequate price signals would include more real time pricing to the demand side of the market as the demand side will be the primary driver of ramping requirements. In each trading interval, generators will balance the incentive to maintain their ramp rate commitment under the causer pays regime against potential spot market earnings available from deviating from that ramp rate. During a significant ramping event, when resource scarcity drives up energy prices, generators should have a large incentive to ramp as quickly as possible, and outperform that ramp rate so as to maximise earnings. This holds unless the expected causer pays costs exceed those earnings.

4) How do stakeholders think a separate 30 minute ramping product would affect available capacity in the spot, contracts and FCAS markets now and in the future?	N/A
5) How do stakeholders think a separate 30 minute ramping product would affect prices in the spot, contracts and FCAS markets, now and in the future?	N/A
6) How could the design of a ramping FCAS product (e.g. criteria for eligible capacity) support competitive outcomes in both energy and FCAS markets?	See 9.1 - Demand side participation will be critical to efficiently managing ramping rates. Consideration should be made to how cost recovery for any service can be achieved on a 'causer pays' principle, thereby encouraging retailers to develop more cost reflective retail products and implement innovative demand management solutions.
7) What are the factors that should be considered when seeking to set and procure efficient levels of ramping services?	Any ramping service should have low barriers to demand side participation.
8) Would Delta's proposed new 30-minute raise and lower FCAS products result in any substantial adverse or unintended consequences in the NEM?	N/A
9) What are the costs associated with establishing new 30-minute raise and lower FCAS products in the NEM? If introduced, how should these costs be allocated?	N/A
10) What kind of incentive/penalty arrangements would be necessary to be confident the new 30-minute raise and lower FCAS products procured are available when needed?	N/A
Question 10: Section 5.4 – Delta Electricity – Capacity commitment mechanism for system security and reliability	
1) Do stakeholders agree with Delta that there is an increasing risk that capacity capable of providing reserves or services may not be available at times when the power system may need them to respond to unexpected events because of increasing incentives to de-commit?	ARENA recognises there are advantages and disadvantages in 'ahead commitments' and that this is also the subject of the ESB Post-2025 Review.
2) Do stakeholders think that a mechanism to commit capacity one day ahead of time would deliver the reserves or services needed? Are there alternatives that could be considered to address this problem?	Day ahead commitments would be made with a high degree of uncertainty of resource availability and market conditions. Same day (for example 6 hourly commitments) could greatly reduce forecasting error in net load and provide for more efficient resource utilisation.

	Even intraday forecasts have been a significant challenge for AEMO and accuracy is becoming increasingly important for unit commitment and demand-side response decision-making.[11] Changing the forecasting horizon for wind and temperature can have a material effect on error. The specific timing of a cool change or cloud bank moving over a generation or load centre can be difficult to predict 24 hours ahead. As such, solar, wind and demand response capacity availability is particularly subject to intraday variability. ARENA is supporting Solcast's Gridded Renewables Nowcasting Demonstration over South Australia that will track and predict renewable output in real time producing forecasts up to six hours ahead in five-minute increments, distributed into 1-2km grids across SA. Solcast will track the real-time evolution of weather systems over SA and forecast the positions and characteristics of cloud cover, as well as improve predictions of wind-speeds at the wind turbine nacelles (above ground) enabling energy generation to be forecast with greater accuracy. The forecasts will also focus on six hour ahead forecasting to provide more accurate information for AEMO's grid operation and enhanced management of generation, energy storage, and demand response.[12] The accuracy of the forecasts will build upon the progress made in the ARENA funded Short-term Forecasting trial. Participants in the trial are confident that onsite, high-dimensional weather forecasting models can outperform AEMO's current system to predict renewable energy generation within a five-minute ahead forecast. Ongoing adjustments to the models will improve the forecasting of wind generation ramps to account for sudden changes in wind direction and cloud cover.
3) Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in reserves and system services?	N/A
4) How do stakeholders think Delta's capacity commitment payment would affect available capacity in the spot, contracts and FCAS markets now and in the future?	N/A
5) How do stakeholders think Delta's capacity commitment mechanism would affect prices in the spot, contracts and FCAS markets now and in the future?	N/A

[11] https://arena.gov.au/assets/2019/07/presentation-intra-day-forecasting.pdf
[12] https://arena.gov.au/knowledge-bank/gridded-renewable-nowcasting-demonstration-lessons-learnt-1/

6) How would a capacity commitment mechanism and payment affect entry, exit and competition in the NEM over the short and long term?	N/A
7) What are the factors that should be considered when deciding how much capacity to commit ahead of time?	N/A
8) Would Delta's proposed capacity commitment mechanism result in any substantial adverse or unintended consequences in the NEM?	N/A
9) What are the costs associated with establishing a capacity commitment mechanism in the NEM? If introduced, how should these costs be allocated?	N/A
10) What kind of incentive/penalty arrangements would be necessary to be confident that the committed capacity would be available throughout the commitment period and/or when called upon?	N/A
Question 11: Section 5.5 – Hydro Tasmania – Synchronous services markets	
1) Do stakeholders consider this rule change proposal presents a viable model for the provision synchronous services? a) Could this proposed model be used to provide the essential levels of system strength (and / or inertia and voltage control) needed to maintain security and the stable operation of non-synchronous generation? b) Could this proposed model be used to provide levels of system strength (and / or inertia and voltage control) above the essential level required for security?	The operation of hydro and thermal generators in 'syncon mode' could increase the hosting capacity for inverter-based renewable energy generation compared to the costly curtailment of renewables to allow for generation from synchronous plant. It is appropriate that the market provide signals for this mode of operation to occur when that produces an efficient outcome for consumers. Innovations in power electronics are rapidly evolving and ARENA anticipates that a range of new inertia and system strength-related services could be provided by inverter-based generation within the next few years. ARENA is supporting a range of trials that demonstrate how inverter-based generation might emulate or substitute for the response of synchronous generation including in relation to inertia and system strength. See 7.2 (above) and 14.1 (below) for examples.
2) Do stakeholders consider that the creation of a synchronous services market could have any adverse impacts on other markets in the NEM? If so, what are these impacts?	N/A
3) Would the proposed model set out in the rule change request efficiently price and allocate costs for synchronous services in the NEM?	N/A

4) Do stakeholders consider the model set out in the rule change request to be capable of sending price signals sufficient to encourage new investment in synchronous capacity?	N/A
5) Do stakeholders consider the rule change provides an appropriate incentive mechanism for existing synchronous generators to make operational decisions to provide synchronous services?	N/A
6) Do stakeholders consider the rule change provides the appropriate locational signals for the provision of synchronous generators to provide synchronous services?	N/A
7) What do stakeholders see as the primary opportunities / limitations of the mechanism as proposed by Hydro Tasmania?	N/A
8) Would the model proposed in the rule change request enable effective competition in the market for the provision of synchronous services?	N/A
9) What suggestions do stakeholders have in relation to the first order changes that would be required in NEMDE to facilitate this proposal and any second order changes that may be required as a result of this rule change proposals' implementation?	N/A
Question 12: Section 5.6 – TransGrid – Efficient management of system strength on the power system	
1) Do stakeholders consider that TransGrid's approach addresses all issues related to system strength currently experienced in the NEM?	ARENA's submission to the AEMC's Investigation into System Strength Frameworks in the NEM[13] set out a range of issues relevant to the provision of system strength from conventional and new technology approaches. ARENA's experience supported the AEMC's assessment of issues related to current frameworks and we agreed that changes are required to support efficient investment in new transmission and generation capacity. In particular, a number of ARENA studies have highlighted that substantial cost savings can be achieved through better-coordinated investment in synchronous condensers, and other remediation strategies, at different system levels. Coordinated investment is not well supported by the current 'do no harm' framework.

[13] https://www.aemc.gov.au/sites/default/files/2020-05/ARENA%20combined.pdf

	Our submission also highlighted that 'system strength' is a bundle of different concepts (For example, fault current and 'voltage stiffness') that each have different characteristics and potential treatments. Some of these solutions fall into the remit of transmission while others have the potential to be offered by third party providers through a competitive framework. For example, Hydro Tas in its rule change proposal has proposed that generators could provide inertia and system strength services through the competitive market. ARENA projects are also demonstrating how inverter-based generators can also support greater voltage stability including through grid formation. SMA has demonstrated that changes to inverter settings can improve oscillatory stability, an issue that is commonly lumped under the broad banner of system strength.[14] In this context, it makes sense to consider the extent that system strength could be provided as a contestable service such as to ensure it remains open to innovation in technology and management practices as they evolve.
2) Do stakeholders consider that a system strength planning standard met by TNSPs would effectively and pro-actively deliver adequate system strength?	N/A
3) Do stakeholders consider TransGrid's proposal will provide useful and timely locational and financial signals to new entrants?	N/A
4) Do stakeholders agree that the 'do no harm' obligations should be removed? a) If so, do stakeholders consider an alternative mechanism is required to regulate or incentivise the minimisation of a new connecting generator's impact on the local network and proximate plant?	Coordinated investment is not well supported by the current 'do no harm' framework. The ARENA-funded *Development of Renewable Energy Zones in the NEM* study compared the business case for a range of measures to jointly address system strength and thermal constraints. The study found that substantial cost savings can be achieved through better-coordinated investment in synchronous condensers, and other remediation strategies, at different system levels. It found that a coordinated approach to investment could reduce costs of synchronous condensers in the study areas by around 85%.[15]
5) What are stakeholder's views regarding generators' being required to make a financial contribution for provision of system strength services?	It is important that generators are only required to contribute to the efficient cost of connection and these costs should be made transparent and firm at the earliest opportunity. If augmentation costs are not contestable, consideration should be given to the sharing of cost savings or overruns such that would encourage cost-effective implementation.

[14] https://www.pv-magazine-australia.com/2020/04/20/testing-testing-5-west-murray-solar-farms-to-return-to-full-throttle/
[15] https://arena.gov.au/knowledge-bank/development-of-renewable-energy-zones-in-the-nem/

6) Would stakeholders be supportive of the ownership of existing private system strength assets being transferred to TNSPs, as suggested in TransGrid's rule change request?	N/A
7) Would the proposed, TNSP-led solution to system strength result in any adverse or unintended consequences for market participants in the NEM?	N/A

CHAPTER 6 – SYSTEM STRENGTH

Question 13: Section 6.1 – Evolving the regulatory definition of system strength	
1) Do stakeholders consider that the AEMC's working description of the effects of system strength, and related problem description of system strength and its components accurately represents all elements of system strength, as experienced in the NEM?	N/A
2) If not, are there other components of system strength that the AEMC should include?	N/A
3) What measures might be used to define system strength? Is fault level the only measure that can be used practically, or are other measures available?	N/A
Question 14: Section 6.2 – Mechanisms to provide system strength above the essential levels that are necessary for security	
1) Do stakeholders consider the centrally coordinated model, as proposed by TransGrid, is the preferable option for providing system strength above the essential levels required for secure operation?	Central coordination can deliver substantial cost savings compared to the current 'do not harm framework', however this does not mean that all services are suited to be provided by the TNSP in all cases. The benefits of thorough investigation into alternative options are highlighted in the ARENA-funded report *Development of Renewable Energy Zones in the NEM*[16] that compared the business case for a range of active and passive measures and the potential to co-optimise investment to jointly address system strength and thermal constraints. Options considered included: • Synchronous condenser • Battery with grid-following inverter • Battery with grid-forming inverter • VRE with grid-forming inverter

[16] https://arena.gov.au/assets/2020/01/development-of-renewable-energy-zones-in-the-nem.pdf

	• Synchronous Static Series Compensator • Network build As noted in ARENA's submission to the AEMC's System Strength Investigation,[17] various projects in our forward funding pipeline propose the use of voltage source inverters and those capable of dynamic reactive power control. It is intended that these projects will help demonstrate: • Ability of advanced inverters to operate stably in low system strength conditions; and • An ability to improve local system strength through i) improved voltage stiffness and ii) improved fault levels Demonstrating the performance of batteries and other inverter-based generation technology, in addressing system strength constraints, is a priority for ARENA. We are working with market bodies, project proponents and network service providers to direct funding to areas of the highest demonstration need.
2) Do stakeholders consider the decentralised, market-based model proposed by HydroTasmania to be the preferable option for providing system strength above the essential levels required for secure operation?	N/A
3) Could a hybrid of these models be used to deliver system strength above the essential level?	N/A
4) What do stakeholders perceive to be each model's strengths and weaknesses?	While ARENA does not take a position on a preferred regulation solution, we suggest the measure of success will be the extent to which that solution provides for: 1) The coordination of investment potentially including shared solutions for multiple generators 2) Transparency in timeframes and costs for generators 3) Appropriate cost and risk allocation to drive lowest-cost solutions, including accommodating innovation over time 4) Operational signals for efficient asset utilisation (where applicable)
5) Do stakeholders consider there are other, alternative models for delivering system strength above the minimum levels required for secure operation?	N/A

[17] https://www.aemc.gov.au/sites/default/files/2020-05/ARENA%20combined.pdf

6) What do stakeholders perceive to be the biggest benefits and risks to introducing a mechanism to deliver system strength above the minimum levels required for secure operation?	N/A

CHAPTER 7 – OPERATING RESERVE SERVICE

Question 15: Section 7.1 – Requirement for a dedicated in-market reserve service, mechanism or market	
1) What do stakeholders see as the key drivers or changes in the NEM that could be addressed by introducing an explicit in-market reserve arrangement?	See above
2) Do stakeholders' think there is a need for an explicit in-market reserve arrangement in the NEM. If yes, do stakeholders consider the need to be permanent or transitional?	See above
3) How would an explicit in-market reserve mechanism or market impact stakeholders? What would be the key benefits and costs? Would it effect stakeholders' operational or investment decisions?	See above
4) Do stakeholders see there to be an explicit need for a capacity commitment mechanism as proposed by Delta? Do stakeholders see this as a separate need to an in-market reserve service?	See above
Question 16: Section 7.2 – Achieving security and reliability using dedicated in-market reserves	
1) Do stakeholders have views on whether an in-market reserve market or mechanism should solve primarily for reliability outcomes and security outcomes second? Or can this be more effectively co-optimised?	See above
2) How do stakeholders see an explicit in-market reserve market or mechanism interacting with the existing NEM reliability framework? What are the policy design priorities for a new operating reserves arrangement that would deliver the reliability needs of the power system?	See above
3) How do stakeholders see an explicit in-market reserve market or mechanism interacting with the existing NEM security framework? What are the policy	See above

design priorities for a new in-market reserve market or mechanism that would deliver the security needs of the power system?	

CHAPTER 8 – FREQUENCY CONTROL

Question 17: Section 8.1 – Reforms related to the provision of synchronous inertia	
1) Do stakeholders consider that the issues relating to declining levels of synchronous inertia have been adequately and accurately described?	See above
2) Are there any other issues related to the provision of synchronous inertia that have not been adequately described?	See above
3) What are stakeholders' views on the approach to considering the interaction between FFR and inertia in the NEM?	See above
Question 18: Section 8.2 – Reforms related to frequency control during normal operation	
1) Do stakeholders consider that the issues relating to frequency control during normal operation have been adequately and accurately described?	See above
2) Are there any other issues related to frequency control during normal operation that have not been adequately described?	See above
3) What are stakeholders' views on the proposed approach to reforming the process for the allocation of the costs of regulation services (Causer pays)?	See above
4) Is the level of specification of regulation services in the NER fit for purpose as the power system transforms?	See above
Question 19: Section 8.3 – Reforms related to frequency control following contingency events	
1) Do stakeholders consider that the issues relating to frequency control following contingency events have been adequately and accurately described?	See above
2) Are there any other issues related to frequency control following contingency events that have not been adequately described?	See above

3) What are stakeholders' views on the best way to address the challenges to managing system frequency following contingency events, including reforms to value and reward FFR?	See above
4) Is the level of specification for contingency services in the NER fit for purpose as the power system transforms?	See above

CHAPTER 9 – INTERACTIONS BETWEEN SYSTEM SERVICES

Question 20: Section 9.1 Technological and temporal issues for system service provision	
1) What are stakeholders' views on how the arrangements for system services can be developed, to best utilise the capability of both established, as well as new and emerging technologies?	See above
2) Do stakeholders have any initial thoughts on how the arrangements for system services can be best coordinated over dispatch, commitment and investment time frames?	See above
Question 21: Section 9.2 – Aheadness and commitment	
1) Do stakeholders agree with the characterisation of arrangements for aheadness and commitment, including the potential benefits?	See above
2) What are stakeholders' views on the potential downsides of introducing arrangements for commitment of capability ahead of dispatch?	See above
3) Are there alternative arrangements that can reduce the increasing uncertainty associated with power system operation in the NEM?	See above
Question 22: Section 9.3 – Cost recovery arrangements	
1) What are stakeholders' views on the appropriate approach to cost recovery for each of the system services discussed in this paper?	See above

2) In each case, how can the cost recovery arrangements be developed to lower the overall costs of the NEM?	See above
Question 23: Section 9.4 – Implementation considerations	
1) What are the challenges or implications associated with implementing proposed arrangements discussed in this paper?	N/A
2) What are stakeholders' views on the prioritisation or staging of the reforms to address the issues discussed in this paper?	N/A