AEMC

Consultation paper - System services rule changes

STAKEHOLDER SUBMISSION TEMPLATE

The template below has been developed to enable stakeholders to provide their feedback on specific questions that the AEMC has identified in the Consultation paper for the System services rule changes.

The rule changes discussed in the system services consultation paper are:

- AEMO – *Primary frequency response incentive arrangements* (ERC0263)
- Hydro Tasmania — *Synchronous services markets* (ERC0290)
- Infigen Energy — *Operating reserves market* (ERC0295)
- Infigen Energy — *Fast frequency response market ancillary service* (ERC0296)
- TransGrid — *Efficient management of system strength on the power system* (ERC0300)
- Delta Electricity — *Capacity commitment mechanism for system security and reliability services* (ERC0306)
- Delta Electricity — *Introduction of ramping services* (ERC0307)

This template is designed to assist stakeholders provide valuable input on the questions the AEMC has identified in the consultation paper. However, it is not meant to restrict any other issues that stakeholders would like to provide feedback on.

Given the breadth of issues discussed in the consultation paper, it is not expected that all stakeholders respond to all the questions in this template. Rather, stakeholders are encouraged to answer any and all relevant questions.

SUBMITTER DETAILS

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ABOUT CS ENERGY

CS Energy is a Queensland energy company that generates and sells electricity in the National Electricity Market (**NEM**). CS Energy owns and operates the Kogan Creek and Callide coal-fired power stations. CS Energy sells electricity into the NEM from these power stations, as well as electricity generated by other power stations that CS Energy holds the trading rights to.

CS Energy also operates a retail business, offering retail contracts to large commercial and industrial users in Queensland, and is part of the South-East Queensland retail market through our joint venture with Alinta Energy.

CS Energy is 100 percent owned by the Queensland government.

GENERAL COMMENTS

CS Energy welcomes the opportunity to provide a submission to the Australian Energy Market Commission's (**AEMC's**) *Consultation Paper - System Services Rule Changes*. CS Energy is strongly supportive of the creation of mechanisms that procure system services and believes these to be critical to the effective and efficient delivery of secure and reliable energy into the future.

CS Energy supports the objective to provide flexible market and regulatory frameworks that can adapt swiftly and effectively in response to the changes of an evolving power system and encourages the AEMC to develop clear standards for the services that would be embedded in the Rules and under the governance of the Reliability Panel. Mechanisms for procuring system and reliability services must have a clear operational (or planning) standard to which they are anchored. This not only provides transparency, efficiency and certainty in system operations, but strengthens the investment signal. While providing transparency to the market, standards grant the Australian Energy Market Operator (**AEMO**) with the flexibility it needs through the associated operational guidelines and processes that provide the necessary technical specifications. A clear standard could then be appropriately reflected in the dispatch and operational planning processes. This would include bids, offers, commitment outcomes together with thresholds (similar to the current Lack of Reserve (**LOR**) process) and publication of headroom and shortfalls.

Overall, the number of proposed rule changes covering numerous essential system services may result in an extremely complex process that could potentially undermine the efficacy of the desired and required outcomes by superimposing layers on existing processes. These will need to be carefully managed and CS Energy encourages the AEMC to consider:

- Reviewing existing standards and developing new standards that explicitly capture the services discussed in the consultation paper;
- Reconsider the grouping of rule changes into a single consultation process. While CS Energy appreciates the AEMC's intent to reduce the consultative burden on stakeholders, this approach may lead to suboptimal outcomes. The individual rule change requests are not necessarily equal in their relative merits, the volume of work required to appropriately explore potential designs including the required cost-benefit analyses, as well as potential implementation pathways. This could see the unnecessary deferral of rule changes that demonstrate benefit and only require incremental changes to the regulatory framework;
- If the rule changes are to remain grouped for consultation purposes, each needs proportional attention. For example, the *Primary Frequency Response Incentive Arrangements* Rule Change has received only a cursory discussion in Section 8.2;
- Providing greater transparency of how this consultation will interact with the Energy Security Board's (**ESB's**) 2025 program beyond the high-level outline provided. Given that the proposed timetable conflicts with the timing of the ESB consultation, CS Energy encourages the AEMC to be more liberal in describing the relevant information to instil confidence that these parallel processes are being effectively managed. For example, only the *Scheduling and Ahead Mechanisms* Market Design Initiative (**MDI**) is discussed despite many of the proposals being similar to options considered by the ESB. Given the ESB work is not yet public, many stakeholders are not versed in these and subsequently cannot provide fully informed feedback to this consultation paper.

CS Energy looks forward to working with the AEMC in the development of mechanisms that value system services.

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?	The rule change processes need to be explicitly integrated with the ESB work program, with transparency of the linkages and considerations through each stage of the process. CS Energy has several concerns regarding how this interaction will be managed as laid out in the consultation paper, as suggested by: **1. Misaligned Timeframes** – CS Energy recognises that the AEMC must adhere to the timelines of the established regulatory process, but the proposed timetable hinders a considered and coordinated approach. Given that some of the rule change requests were lodged mid to late 2019 yet only initiated now suggests the flexibility to consider a timetable more coordinated with the ESB process. This is exemplified by the timing of this consultation, with submissions due on 13 August 2020 while the ESB is releasing its public consultation paper at the end of August. This fails to provide the ESB with the option to incorporate feedback from this process into its consultation, nor does it allow stakeholders to understand the ESB's initial thoughts and their relevance to this process. Such obvious clashes in timetables, even unintentional, does not evoke confidence that this consultation process will be efficiently integrated with the ESB 2025 program. **2. Lack of transparency** – Section 1.2 provides a high-level overview of the ESB process and how the AEMC intends to regularly communicate with the ESB on interlinkages, with this interaction strengthened by its membership in the ESB. This does not provide any practical information about how the integration will be actively managed. It would be useful for stakeholders to understand for example: • How any divergences between the different processes will be managed. • What decision points determine whether a solution proposed by any of the rule change requests should dovetail into the ESB process while this process potentially considers the no regrets mechanisms only. • How the assessment processes will align between the two given the different remit. This is discussed in question four below. **3. Asymmetry of information** – the apparent lack of transparency and coordination has manifested in the consultation paper's dearth of information about the ESB 2025 program and the interactions. Aside from the infographic, discussion of the rule change requests as well as those on the broader topics of system strength and frequency control only provide a cursory

reference to the relevant MDI. Given the lack of public information on the ESB process, most stakeholders are not privy to the options being considered and why, let alone are able to understand the potential interactions. The AEMC needs to clearly articulate exactly how these rule changes may or may not interact with the ESB's program in its consultation for it to be effective.

Despite the direct parallels between some of the rule change requests and the 2025 process (operating reserves for example) not being discussed, the consultation paper then devotes an entire section (9.2) to mechanisms for "aheadness". Focusing on only one of the seven MDIs presents a very skewed approach to the consultation and potentially risks unintentional bias in the broader interactions with other MDIs.

The interaction with other processes needs to be considered holistically, with the same level of information for each. This is true also for the rule change requests, with the proposal related to primary frequency control not given adequate treatment in the consultation paper.

4. **Scope of interactions** – the consultation paper does not identify how the rule changes interact with three MDIs, stating that the interactions are more dominant with the other MDIs. This may appear true at first glance, but it does not mean these interactions are not important or material. Firstly, the Coordination of Generation and Transmission Investment (**CoGaTI**) stream is considering implementing locational marginal pricing, with the intent that this will resolve transmission congestion challenges and indirectly provide price signals for system services. In this respect, its interaction with potential mechanisms to procure systems services is critical. Furthermore, it is important to assess whether mechanisms to address reliability affect network access and congestion.

   Given that the need for system services is being driven by the changing technology mix, the role of Distributed Energy Resources (**DER**) cannot be ignored. Neither can the potential benefits that DER and demand side response can provide to new mechanisms, with many of the rule change requests citing these opportunities. Given that the demand side is contributing to operational challenges and the two-sided market MDI is seeking to facilitate its participation in these potential mechanisms, these MDIs cannot be ignored. In fact, in its consideration of interactions with the Renewable Integration Study (**RIS**), the consultation paper highlights the importance of integrating DER in this context.

The interdependencies of these rule changes and the ESB process requires greater transparency and communication to facilitate efficient consultation with stakeholders, and a truly informed, coordinated approach.

CS Energy cautions against drawing interactions with the Integrated System Plan (**ISP**) when considering system service procurement mechanisms. The ISP is a long-term network planning model

	and provides an excellent snapshot of the projected network planning needs, but it does not yet properly consider system services (nor was it designed too). While AEMO is working to integrate system security considerations into the ISP, at present, they are largely considered ex-post and thus do not capture the true need. This rule change process should consider the ISP work as an initial input but as it progresses, it is assumed that it would set an agenda of work for AEMO that better articulates the nature of the need and hence, guide the design of efficient mechanisms. This would be similar to the Frequency Control Frameworks Review (**FCFR**) workplan and represents a progression of the RIS. This would need to include: • How the dynamic status, availability and quantity of system services in the NEM are measured, quantified and communicated to the market. • Leverage the work already undertaken by the ESB and market participants on the efficacy of the existing scheduling and pre-dispatch processes in accommodating these requirements for both AEMO and market participants. The AEMC needs to ensure a holistic and thorough approach to assessing these rule changes to minimise the layering of existing processes.
2) Are there any additional processes that should be closely considered by the Commission when progressing these rule change requests?	The AEMC should be considering how this process integrates with work either underway or completed by stakeholders external to the market bodies. Consumer groups have been exploring assessments of consumer impacts of the options being discussed in the MDIs, while the Australian Energy Council (**AEC**) engaged consultants to assess the options considered in the *Scheduling and Ahead Mechanisms* MDI to better understand the potential impacts on industry, and thus consumers.[1] This work represents an independent assessment of ahead mechanisms and highlights some of the contradictions in the need for such mechanisms and their efficacy in addressing the operational challenges.
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?	In principle, the proposed timetable is reasonable but cannot be appropriately assessed without further detail of how the interactions with other work will be managed, especially given the misalignment of timing with the ESB consultation process. As outlined above, the individual rule changes should not be automatically subjected to the same timetable. CS Energy is concerned that the development of mechanisms to incentivise Primary Frequency Response (**PFR**) will be unduly delayed because of this approach. This was initiated in the FCFR and was part of the consultation process for the mandatory provision of primary frequency response. The latter was given a sunset clause of 2023 with the understanding that incentives for this

[1] Creative Energy Consulting, *Scheduling and Ahead Markets – Design options for post-2025 NEM*, June 2020

	service would be developed and implemented as a priority. CS Energy would expect a more accelerated timetable for this rule change relative to the others.

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?	It is unclear what the objective of grouping the rule changes is, given the paper details the potential need to separate rule changes out from this process as well as the need to consider each rule change over all the timeframes despite the grouping. The AEMC has also asked whether operating reserves are considered a security or reliability service, highlighting the need to unpack the rule changes and clarifying the intended outcomes prior to any grouping. CS Energy would prefer any grouping to be done based on what the rule changes are physically delivering, but further clarity needs to be provided on the purpose of grouping given the required need for a holistic approach. CS Energy is concerned that considering mechanisms for commitment in parallel to dispatch may inadvertently create inefficiencies given mechanisms procuring services in dispatch and their regulatory framework will provide a level of coordination that reduces any perceived commitment challenges. Treating these mechanisms separately thus runs the risk of overstating the challenge which will have flow on implications for the market and consumers.
2) Do stakeholders believe that Figure 3.1 captures the key issues to be considered for each rule change in each time frame?	CS Energy does not consider Figure 3.1 to be particularly useful as it confuses key issues with design elements and doesn't adequately highlight interdependencies. The proposed rule changes all have the same underlying challenge, that is, the growing need to explicitly value a service(s). • Specification of the service is required for all, ideally via operating standards and/or tied to the reliability standard. The specification of the service determines the minimum level for satisfactory operation and thus is relevant in the dispatch timeline. The procurement mechanism and associated market signals need to be based on this standard and provide investment signals across all timeframes. • The nature of the required volume and frequency of the service will determine the efficacy and efficiency of procurement mechanisms. The AEMC will need to assess the benefits and risks of these mechanisms against spot markets, regulated processes, structured procurement or a hybrid across all three streams. • The issues in Figure 3.1 regarding commitment requirements risk conflating the issues and need to be framed in terms of developing a pricing mechanism that will coordinate a market response.
3) Do stakeholders have views on whether/which services should be procured in certain time frames and not others?	CS Energy disagrees with the premise of this question as it implies a solution definition without first specifying the problem. The procurement of services (type, volume and mechanism) is dependent on the

	underlying need. This need will determine over which timeframe solutions should be procured to efficiently and effectively maintain power system security and reliability. It is interesting that while key challenges related to the changing system dynamics are discussed recognising that there will be a new operating paradigm with greater variability, the approach to solutions doesn't appear to consider redefining what the "new normal" is operationally. CS Energy posits that this would be the initial step prior to evaluating procurement timeframes. Infigen and TransGrid did touch upon this by identifying potential new standards but the consultation paper has not drawn this out effectively. Without defining the parameters for the new normal, some of which should naturally be developed through this process, there is the risk that any regulatory frameworks established will not be effective and definitely not efficient. The AEMC must first determine the operational timeframe to which the solutions need to map, and then investigate how a procurement framework may drive required changes in bidding, commitment and the provision of market information. Further discussion is provided below in the relevant sections.

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?	CS Energy agrees with the proposed system services objective but would like to see a review of operating standards to better reflect the evolving power system to which this objective is anchored. This will retain the technology neutrality aspect thus accommodating potential new service providers (technology and business model). It will also address the desire for a degree of operational flexibility within any system service mechanism over time as the needs evolve. As per the NEM framework, explicit operating standard(s) for system services would provide the physical metrics for the power system while associated operating guidelines specify the technical requirements for service provision. AEMO has responsibility for these guidelines and can initiate their review when needed. This provides the most effective trade-off between certainty and flexibility.
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?	CS Energy agrees with the '4Ps' framework but would like it to include the need for standards where appropriate.
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?	The assessment principles would be appropriate if these rule changes were standalone, but CS Energy is concerned in how they will be applied in the broader context of the 2025 reform. The principles represent

	threshold criteria for any change to the regulatory framework that will prove beneficial, but it may not mean that they are the "best" option for the challenge they are trying to address. This is attained through a holistic assessment of options that the ESB are considering, and without further detail on how these interactions are going to be managed, it is difficult to properly assess these principles. The AEMC is required to perform its assessments with the current rules' framework as the benchmark.[2] That is, it cannot perform a holistic assessment of proposed rule changes within a potential future framework. This risks a suboptimal outcome and thus, CS Energy would appreciate greater transparency on how these principles will be applied and considered in this context.

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?	The issues raised by Infigen are legitimate and have previously been outlined in the FCFR and witnessed in South Australia with the invocation of Rate of Change of Frequency (**RoCoF**) constraints. The issues raised have predominantly focussed on raise capability, but the lower capability is equally important to ensure that both high and low frequency events are managed appropriately in the long-term. Outcomes from the PFR rule change will also need to be considered here in determining the need as well as any mechanisms for inertia. This rule change request should be considered alongside a broader review of the appropriateness of current contingency timeframes.
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?	CS Energy believes that the framework for frequency control following contingency events needs a holistic review, including the need for a fast service such as Fast Frequency Response (**FFR**). A standard for RoCoF should be explored, and a mechanism developed that considers the provision of inertia and FFR. Linkages with PFR should also be considered. A RoCoF standard sets the procurement requirement and provides transparency to the market. Given the interdependencies of primary, secondary and tertiary frequency control, this review should consider whether the current six raise and lower markets are still appropriately defined.

[2] For example, in the final determination for the Wholesale Demand Response Mechanism (**WDRM**) (p.244), the AEMC stated that it can't consider the interaction with other potential mechanisms (in this instance, CoGaTI) as they were not yet Rules.

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?	In addition to the issues that have previously been discussed in other processes, a lack of visibility of requirements and supply (both current and projected) to the market is a concern.
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?	As per Q2. There also needs to be an assessment of the efficacy of the recent PFR rule change and the potential introduction of incentives for its provision. Understanding the gap between what is provided by PFR and what is required will determine the need for an FFR market. Frequency control can also be improved by the enforcement of Wide Band Frequency Response (±0.5Hz, outside 49.5-50.5Hz) as specified in the Rules and Generator Performance Standards that provides a safety net in the event of a major supply disruption and/or the occurrence of a non-credible contingency event(s).
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?	5-minute markets for FFR ancillary services may be feasible but need to consider the procurement of inertia and PFR.
6) Do stakeholders consider Infigen's proposal will provide adequate pricing signals to drive efficient investment in FFR capability in the NEM?	This cannot be determined until further details are provided particularly around pricing signals and the projected need.
7) What are stakeholders' views on, if introduced, how the costs associated with any new FFR market ancillary services should be allocated?	As a contingency service, costs should be recovered as per the broader contingency framework. However, given the changing nature of supply and demand, the AEMC may need to redefine how costs are passed through to market customers and generators to capture the contribution from DER and non-scheduled participants.
8) What do stakeholders consider to be the likely costs associated with establishing two new ancillary service markets for FFR in the NEM?	Implementation costs would include system changes to accommodate the new bid structure and potential changes to control systems. There would be costs associated with telemetry and measurement of compliance, as well as the additional compliance processes.
9) What are stakeholders' views on how the proposed solution may result in any substantial adverse or unintended consequences in the NEM?	The proposed solution itself shouldn't result in unintended consequences but how it is assessed within the context of the other changes and processes may if not effectively managed.
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?	The following should be considered: • The development of an RoCoF standard including the inter-relationship with inertia • Consideration of the interaction of PFR and FFR to avoid any duplication or inefficiencies • Broader review of the contingency markets and/or greater transparency of progress of the FCFR work plan.

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?	CS Energy agrees that operating reserves are a viable mechanism to address tight capacity conditions and uncertainty in market outcomes. As per stakeholder discussions regarding the need to value headroom for the effective provision of PFR, an operating reserve would provide incentives for reserve capacity in the operational timeframe. As identified in AEMC's System Security and Reliability Action Plan, the power system is becoming more probabilistic rather than deterministic and this is true for contingency events. The emergence of protected events and operating to *N-1+* will likely create tight capacity conditions at times over the next few years.
2) Are there alternative solutions that could be considered to address tight capacity conditions and increasing uncertainty in market outcomes?	The discussion in the consultation paper creates confusion in the objective of the proposed operating reserves mechanism. On one hand, it cites the growing variability in both supply and demand as challenges to be addressed, and on the other, cites the role of reserves in combating the new modes of failure that are expected to emerge. CS Energy suggests that the AEMC first clarify which challenge operating reserves are intended to address as this will affect its design: • If variability is to underpin the new normal operating state, then addressing this uncertainty needs to be encapsulated in the technical envelope and potentially addressed by a form of regulation Frequency Control Ancillary Services (**FCAS**). If addressed by operating reserves, then the reserves would serve as a flexibility service that counteracts this variability. • If operating reserves are to address new modes of failure, then it will be important to not confuse them with FCAS that is defined as contingency capacity reserve. Clarity on how operating reserves align with the indistinct and distinct events framework would also be required. Other alternative solutions have been articulated in the ESB process.
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?	Operating reserves could provide adequate pricing signals for investment, but this depends on the design as well as the outcome of the broader reform program, and they do not replace scarcity pricing in the spot market. It is naïve to consider these potential mechanisms in isolation and difficult to provide thorough comment. Operating reserves will provide much stronger investment incentives than out-of-market reserves and will likely provide greater opportunity for new participants such as demand response. They are generally recognised as providing a "price kicker" that assists participants with cost recovery.

	While they may also quell community concerns with reliability and thus indirectly assist investment certainty, there would need to be certainty and transparency in how the Forecasting Uncertainty Measure (**FUM**) would be applied to set the volume and CS Energy agrees that this would need to have the oversight of the Reliability Panel.
4) How do stakeholders think separate operating reserves arrangements would affect available capacity in the spot, contracts and FCAS markets now and in the future?	This is obviously subject to the outcome and process, but it is anticipated that participants will continue to exercise judgement on how to optimise energy, FCAS and operating reserves in response to actual and forecast market conditions and their contracted positions.
5) How do stakeholders think separate operating reserves arrangements would affect prices in the spot, contracts and FCAS markets now and in the future?	This depends on the specific pricing mechanism for operating reserves as well as FFR, as well as the forward demand curves. An operating reserve may assist participants in meeting their liabilities under the Retailer Reliability Obligation (**RRO**).
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?	The development of an operating reserves standard which considers the FUM is critical, and the mechanism would need to be reconciled with the Lack of Reserve (**LOR**) process and current thresholds. The distinction between operating reserves and contingency FCAS would need to be explicit and have clear rules on when each is activated to maintain competitiveness. The AEMC would also need to consider how this mechanism interacts with the WDRM and RRO, particularly if there is a large proportion of demand side participation in the reserves market.
7) What are the factors that should be considered when seeking to set and procure efficient levels of operating reserve?	Clarify the objective of the operating reserve mechanism and thus determine a suitable metric by which procurement and performance is based. CS Energy believes an operating reserves standard is most appropriate.
8) Would Infigen's proposed operating reserve market result in any substantial adverse or unintended consequences in the NEM?	Difficult to determine at this stage, however, if Demand Response Service Providers (**DRSPs**) are eligible to participate, then this would impact retailers who remain liable for the entire baseline consumption of these customers under the RRO. Participants may engage in arbitrage between operating reserves, energy or FCAS or any other priced commodity arising from this consultation.
9) What are the costs associated with establishing an operating reserve market in the NEM? If introduced, how should these costs be allocated?	Implementation costs would be similar to those of an FFR market. If operating reserves were implemented to manage the increased variability in the supply and demand sides, a causer-pays type arrangement should be considered.
10) What kind of incentive/penalty arrangements would be necessary to be confident the operating reserves procured are available when needed?	Any new market mechanism will require adherence with current Rule obligations including bidding in good faith in addition to bids/offers not being misleading or false.

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?	CS Energy is not supportive of Delta's proposed introduction of ramping services as presented. It is true that coal assets are facing decisions about maintaining units online during the day when solar output is high and wholesale prices are suppressed and even negative and drawing upon higher prices at other times of the day to mitigate these losses. If units were withdrawn or two-shifted during the day, CS Energy agrees that this may lead to a shortfall in the ancillary services that they provide that are currently not valued. Valuing these services however, is a focus of some of these rule changes and the 2025 program and mechanisms stemming from these will be more efficient in this regard. The ramping service proposed will not solve longer-term challenges in incentivising system services and is targeted at providing synchronous generators, namely coal plant, payment to stay online during times of low prices. While CS Energy may be able to offer such a service, it does not believe that the current proposal is best for the market and hence consumers as it does not address the underlying challenges and is not technology neutral. If the AEMC were to progress this proposal, it is suggested that mechanisms for procuring system services with explicit market signals be considered first and then an assessment conducted to see if there are gaps that would justify a ramping service. Furthermore, the demand profile which the rule change is addressing is considered the new normal in terms of daily load profile. It is expected, it is forecast, and clear market signals are provided to participants with participants already capable of responding to actual or forecast price volatility arising from demand changes. Price volatility during demand run up and run down during reliable and secure operation are legitimate outcomes reflecting the capability and limitations of the supply side during periods of rapid demand change. This volatility provides the operational and investment signals. The Rate of Change (**ROC**) capability in the NEM is published in AEMO registration records and presently, the level of ROC available across the NEM is high. In fact, there is latent capability currently not being fully utilised. Participants' ROC must not be less than 3MW/min unless there are legitimate reasons to operate below that value. The participant will trade off increased ROC against incurred maintenance costs and reflect it in their bids and the forecast price.
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?	Price volatility is a legitimate and inherent feature of the market. If the concern is retaining synchronous services online, then the alternatives considered in the ESB program are preferential.
3) Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in ramping services thanks existing price signals and information provided through the PASA and pre-dispatch processes?	No, the proposed 30-minute resolution of Delta's proposal will not provide signals additional to those captured in pre-dispatch and Short-term Projected Assessment of System Adequacy (**ST PASA**).

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?	The supply demand balance will remain unchanged, but the mix of energy suppliers will change with the supply being delivered by separate mechanisms. Depending on the design, it may not provide the required visibility to execute appropriate contract derivatives.
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?	It is difficult to determine without further detail, but one would expect prices to increase.
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?	CS Energy posits that a ramping FCAS product would duplicate existing services and potential new services that would provide more effective investment signals. Given it is targeted to a subset of participants only, it will likely decrease competition.
7) What are the factors that should be considered when seeking to set and procure efficient levels of ramping services?	Pricing outcomes already provide this signal by reflecting the mismatch between ROC and changing demand.
8) Would Delta's proposed new 30-minute raise and lower FCAS products result in any substantial adverse or unintended consequences in the NEM?	Delta's proposal as it stands is unlikely to lead to the most efficient outcomes and CS Energy is not yet convinced of the need.
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?	If a ramping service were to be implemented to address the solar generation profile, the simplest cost allocation would be a causer-pays approach. This, however likely violates the technology neutrality of the rules, so a user-pays approach would be more likely, where the system and consumers are the beneficiaries.
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?	While CS Energy does not support this rule change, if introduced there would need to be strict adherence with current Rule obligations including bidding in good faith in addition to bids/offers not being misleading or false. There would need to be frameworks in place to verify the costs of operating at minimum load for each unit, and clear rules on what timeframes across the day that the service would be enabled.
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?	CS Energy agrees with there being an increasing risk of a shortfall in system services that are not currently valued at times and that capacity mechanisms may be a viable option. However, CS Energy disagrees with how the challenge has been framed in Delta's proposal. It is not a commitment issue or incentives to de-commit but rather a lack of the appropriate signals across operational and investment timeframes for this capability. Without any signal, participants will not base their operational decisions with system services in mind nor will they necessarily incorporate the required capability in new investments. Whether there is a commitment problem can only be assessed once mechanisms that procure system services are developed and embedded in the operational psyche. The market will not coordinate itself to deliver services that have no value placed on them.
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?	Ahead market commitments may provide confidence in the operational timeframe, but they do not address the challenges in the broader timeframes. The proposal will not provide an investable signal for

	future capability and seems to be an alternative intervention framework with no adequate long-term signals. Also, it is known that day ahead commitments are not efficient in a more variable power system, as better information and forecasts are available closer to dispatch. Requiring commitment decisions, a day ahead means participants will provide offers based on the expectations at that time which would likely lead to over/under procurement. CS Energy refers the AEMC to the ahead market consultancy prepared for the AEC as well as considering the other options being explored by the ESB and this process, in particular the Unit Commitment for Security.
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?	No.
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?	This is heavily dependent on the other mechanisms and the eligibility to participate in this market.
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?	This mechanism would possibly reduce the spot prices depending on the volumes procured and consequently prices of forward contracts. The committed capacity would displace other supply and possibly put upward pressure on lower FCAS services due to the erosion of foot room.
6) How would a capacity commitment mechanism and payment affect entry, exit and competition in the NEM over the short and long term?	This can't be considered independently of other potential mechanisms and any rule changes relating to commitment need to be deferred until the service procurement mechanisms are developed.
7) What are the factors that should be considered when deciding how much capacity to commit ahead of time?	Any capacity procured needs to be tied closely to a relevant operating standard and/or the reliability standard. Procuring capacity ahead of time should be based on a projected shortfall so as to create the most efficient market outcomes.
8) Would Delta's proposed capacity commitment mechanism result in any substantial adverse or unintended consequences in the NEM?	Several aspects of Delta's proposal need consideration to ensure it is technology neutral and will deliver benefits above the costs. Delta has indicated that non-market participants would be eligible to participate. CS Energy seeks clarification on how this would be structured. One would expect that all participants in this mechanism would need to be scheduled and be registered market participants to maintain consistency with the current FCAS rules. Any mechanisms need an equitable playing field in terms of the obligations and compliance on participants, transparency of information to the market and technology neutrality. If generators committed under the mechanism are operating at minimum output across the trading day regardless of whether a shortfall exists in all the trading intervals it would potentially result in an inefficient dispatch for these periods.

	Committing an operating reserve day ahead may create unintended consequences as generators may withdraw capacity to create an artificial shortfall in order to secure an ahead commitment depending on prices rather than responding to price information in pre-dispatch.
9) What are the costs associated with establishing a capacity commitment mechanism in the NEM? If introduced, how should these costs be allocated?	Significant implementation costs in systems for participants and AEMO, with the market now being multi-settlement. It also depends if the market settlement would be balanced for each trading interval as this would have flow-on impacts. Costs for the payment of these services including any overcommitments should be allocated to the beneficiaries. The beneficiaries include customers and plant that can participate in the market by virtue of the services provided by the capacity commitment mechanism.
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?	Adherence with current Rule obligations including bidding in good faith in addition to bids/offers not being misleading or false and any requirements arising from the capacity commitment mechanism. Firm accountability and reporting on AEMO would be required to ensure volumes procured are appropriate.
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 rule change provides a viable model to an extent with limitations arising from the bundling of the services and potential lack of visibility of required signals for service delivery. For example, it is limited to optimisation with the five-minute dispatch but would also need to be extended into the operational decision-making timeframes such as pre-dispatch and S TPASA. While the feature of the optimisation of synchronous and non-synchronous plant is attractive, bundling the synchronous services may not provide the required level of transparency to the market. For example, which of the services is setting the constraint for each dispatch interval. It is also difficult to determine whether this model would incentivise sufficient capability to be online when required.
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?	Bundling the synchronous services may result in unexpected impact on current FCAS markets and potential new markets such as PFR and FFR.
3) Would the proposed model set out in the rule change request efficiently price and allocate costs for synchronous services in the NEM?	CS Energy is concerned that bundling synchronous services as proposed will not produce an efficient price outcome unless the pricing regime can be structured to align prices with a specific synchronous service(s). It is likely that this bundling will dilute optimisation outcomes delivered by utilising constraints.

	Cost allocation is not limited to customers as the outcome also enables non-synchronous plant to commit that otherwise would not be possible if the required level provision of synchronous services.
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?	No. As per Q1, the proposal is focused on the dispatch optimisation and it is unclear what market signals will be provided across all timeframes. A more explicit pricing mechanism such as contracts or markets is more likely to provide the required signals to encourage new investment and over time reinforced by spot market outcomes reflecting price and allocative efficiency.
5) Do stakeholders consider the rule change provides an appropriate incentive mechanism for existing synchronous generators to make operational decisions to provide synchronous services?	The potential is diluted by the bundled nature of the synchronous services. What is lacking is the forecast headroom or shortfall of synchronous service(s) through a pre-dispatch process to enable timely operational decisions to provide synchronous services.
6) Do stakeholders consider the rule change provides the appropriate locational signals for the provision of synchronous generators to provide synchronous services?	No. The bundled synchronous services hide the fact that some services, such as inertia are regionally effective, while other services such as voltage and system strength are limited in their sphere of effectiveness. Constraints can be developed to reflect local requirements and if the process identifies the limiting synchronous service(s) then it may provide the appropriate locational signals for the provision of synchronous services.
7) What do stakeholders see as the primary opportunities / limitations of the mechanism as proposed by Hydro Tasmania?	An appealing feature is the optimisation of the synchronous and non-synchronous plant in dispatch but as discussed above, it is limited by the lack of a forecast outlook and the bundled nature of the synchronous services.
8) Would the model proposed in the rule change request enable effective competition in the market for the provision of synchronous services?	Potentially yes, subject to the visibility of the individual synchronous services. The ability to submit participant offers would enable effective competition in dispatch but a lack of investment signals could undermine the effective competition going into the future.
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?	For this proposed model to be effective the following are required: • Unbundling the synchronous services into discrete services. • Extending the mechanism into the pre-dispatch and STPASA timeframe reporting both headroom and shortfall of synchronous services. • Ensuring constraints reflect the individual synchronous services.
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?	It is difficult to envisage system strength as a competitive market in future given that it is localised and difficult to define. CS Energy supports the establishment of a planning standard for system strength as this will allow for a proactive approach to managing system strength needs rather than the current reactive and ad hoc process which is highly inefficient.

	Natural tensions arise between network solutions and competitive processes, and the AEMC needs to consider whether system strength can be commoditised such that a competitive and efficient procurement mechanism can be developed and incentivise future investment. If no, then a planning standard with appropriate regulatory requirements on TNSPs should be assessed to determine whether it represents a more efficient approach. In this case, if system strength was considered the remit of TNSPs, there would be no priced mechanism for which they would be competing, and any network-owned system strength assets would not be market participants so there would be no requirement for ring fencing. Frameworks however, would need to ensure that the procurement of system services considered competitive auctions from market participants who could provide solutions not just investment in new network assets. This is particularly relevant for procurement of system strength above the minimum level with clear parameters on the volume that can be procured. A network planning standard for local system services will have the additional benefit of providing crucial support services during emergency situations including system restoration following a black start. This situation requires that networks have enough system strength, along with appropriate voltage and frequency management to assist in line energisation and load restoration. Having local services such as system strength embedded in the network operational standard would ensure this network support and may create efficiencies through a reduced procurement of system restart support services.
2) Do stakeholders consider that a system strength planning standard met by TNSPs would effectively and pro-actively deliver adequate system strength?	A system strength planning standard has the potential to deliver adequate system strength provided the framework is carefully defined. CS Energy agrees with the role of the Reliability Panel in determining the standard. A forward looking standard provides more visibility to the market than present but the reliance on the ISP in setting the standard means that the standard will only be met should new generation assets locate where projected. Consideration will need to be given to how best to accommodate the risks of investing based on long-term forecasts particularly input parameters such as generator retirement dates can change. As per above, TNSPs must be required to undertake competitive tender processes in procuring system strength.
3) Do stakeholders consider TransGrid's proposal will provide useful and timely locational and financial signals to new entrants?	This depends on the aspects of the framework such as the 'do no harm' provisions. Locational signals would be provided to new entrants based on whether connection would impose system strength requirements in particular locations. This would be an indirect financial incentive. The need for financial signals to new entrants for providing system strength services would arise from the competitive tender process that TNSPs would need to conduct when procuring for system strength.
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?	The 'do no harm' obligations should remain to manage risks associated with new entrants locating in areas of the network not forecast in the ISP and thus in the system strength needs. However, stricter requirements on AEMO and TNSPs in providing system strength analysis to new entrants in a timely manner need to be established. Provisions also need to be developed to allow shared assets across parties and bilateral contracts with other participants.

5) What are stakeholder's views regarding generators' being required to make a financial contribution for provision of system strength services?	If a party is identified as being a contributor to the need for the provision of system strength services, then it should be allocated its proportion of the cost for the provision of the required system strength services. The proposal to establish a process to renegotiate generator performance standards for existing plant[3] would need to consider appropriate grandfathering arrangements.
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?	Private assets should remain as is but could be contracted by TNSPs through a competitive process to meet system strength requirements.
7) Would the proposed, TNSP-led solution to system strength result in any adverse or unintended consequences for market participants in the NEM?	The proposed solution would need to have very clear frameworks addressing system strength remediation for new connections not located as per the ISP as well as clear frameworks for how any additional investment to meet unexpected system strength issues that emerge must follow.

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?	The working description is appropriate and will be critical to the development of an appropriate standard.
2) If not, are there other components of system strength that the AEMC should include?	None identified at this stage.
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?	The use of fault level as a proxy for system strength was expedient in addressing an immediate power system security challenge. Further insight has since occurred on the key components in defining system strength such as the correlation between the Short Circuit Ratio (**SCR**) and voltage regulation. A higher SCR value produces better voltage regulation. Any measure of system strength must incorporate voltage and fault level that is practically implementable to facilitate a procurement outcome.
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?	Given its complexity and localised nature, system strength may not lend itself to market-based mechanisms. In this respect, the centrally coordinated model proposed by TransGrid warrants consideration provided appropriate frameworks are in place, including a competitive tender process to provide services and AEMO remaining a procurer of last resort.

[3] AEMC, *Consultation Paper -System services rule changes*, p47

	CS Energy is also keen to see how this solution would integrate with work on future network resilience.
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?	The HydroTasmania model should be considered if the concerns outlined above are addressed it can be designed to provide the required long-term signals.
3) Could a hybrid of these models be used to deliver system strength above the essential level?	Potentially.
4) What do stakeholders perceive to be each model's strengths and weaknesses?	Please refer to comments above specific to each rule change.
5) Do stakeholders consider there are other, alternative models for delivering system strength above the minimum levels required for secure operation?	Please refer to comments above.
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?	Introducing a system strength mechanism for delivery of the service above the minimum to ensure secure operation will capture 'missing markets' and at the same time there is provision of a safety net with specified minimum levels. This will provide a level of resilience to the system that will be responsive to the evolving needs.

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?	The key drivers for an in-market reserve arrangement are: • A changing expectation on the level of reliability that should be achieved, resulting in the inefficient use (and introduction) of out-of-market reserves to avoid load shedding beyond the level of the Value of Customer Reliability (VCR). Overall investment confidence is low, and an in-market reserve arrangement would manage some of this risk. • The NEM technical envelope is changing including the introduction of new frameworks for the type and quantum of contingency events (protected events and indistinct events). These will likely erode into the levels of capacity reserves with the transfer of energy into the contingency FCAS to reflect the increased requirements. • The level of reserve generators have in the market are necessarily asset/portfolio based considering contract positions and/or plant characteristics. As per discussions in the PFR consultation, maintaining reserves have an operational cost and so will only be available to the market if there are clear incentives. In considering an in-market reserve mechanism, the AEMC needs to further consider its objective as a reserve addressing new modes of failure is different to a reserve to manage the variability and uncertainty of the power system during normal operations. The latter is forecastable, and the system

	will need to tolerate a level of variability as the "new normal" to be efficient. In this case, regulation FCAS services may need to be redesigned to be flexible to this variability. The interaction of operating reserves and regulation services would need to be considered in this context, with operating reserves providing a confidence buffer additional to regulation services.
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?	Reserves, like other services have not been explicitly valued in the past as they have been plentiful and wholesale prices provided the required investment signals. The combination of government intervention and the changing dynamics of the power system is driving the need for operational reserves. An in-market reserve arrangement would be expected to be permanent, and like all functioning markets, it would only be operationally active if, and when, the power system required the reserve. It would need to have a clear objective, and an operational standard derived to reflect this objective. Clear distinctions would need to be drawn between the role and activation of operating reserves and contingency FCAS.
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?	The impact on stakeholders' operational or investment decisions would be dependent on the supply availability of in-market reserves and the forward demand curve. If an explicit price signal was present for reserves, then this would be considered in operational decisions to manage assets physically and commercially. Reserve payments may assist generators recoup losses incurred during periods of sustained low prices and may assist in the economic viability of existing assets. It is also anticipated that participants would be able to utilise this reserve market (directly or via bilateral contracts) to manage their liabilities under the RRO. Other benefits include: • Investment decisions would consider the value of reserves but would be contingent upon the ongoing certainty of that market. • Benefits will also accrue from a reduction in directions, Reliability and Emergency Reserve Trader (**RERT**) contracts and activation and the out-of-market reserve mechanism currently being implemented, leading to more efficient outcomes. • An explicit mechanism for reserves may also facilitate greater demand response participation. • Valuing the service with the development of a standard will provide the market with transparency. Costs would include changes to participants' and AEMO's systems and of course payment for the service whether activated or not.
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?	CS Energy disagrees with Delta's proposal and posits that the concerns raised can be managed by the current rebidding obligations that provide the required visibility on commitment decisions, a forecasting process that reports headroom and shortfalls in capacity reserve, and an alert mechanism such as a modified LOR seeking a market response for the provision of in-market reserves.

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?	The technical envelope characteristics define the capability of the power system and reflect the existing NEM reliability and security frameworks. The technical envelope is represented by constraints in the market processes with constraint violation penalties utilised in the NEM dispatch engine to prioritise security over reliability. In the operational timeframe relevant to in-market reserves, whenever a shortfall is identified, the LOR mechanism is triggered seeking a market response for the provision of capacity reserves. Unless the available capacity reserves fall below a threshold, then the security and reliability are managed concurrently. On the occurrence of a capacity reserve shortfall, security takes precedence over reliability. This process is envisioned to prevail for in-market reserves. The operating standard for procuring in-market reserves will need to be explicit and appropriately manage security and reliability elements. For example, if based on the FUM, it would need to be set at a level that facilitated secure operations but accounted for the economic trade-offs for reliability as set by the reliability standard.
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?	An in-market reserve market may require a review of the NEM reliability framework to ensure there is consistency between the framework and processes and justification for any costs that are incurred by the customers. The contingency event definitions and their application should be reviewed to ensure seamless incorporation of protected and indistinct events and clearly delineate the role of operating reserves and contingency FCAS.
3) How do stakeholders see an explicit in-market reserve market or mechanism interacting with the existing NEM security framework? What are the policy design priorities for a new in-market reserve market or mechanism that would deliver the security needs of the power system?	A fit for purpose LOR process with appropriate thresholds covering the operational timeframe of dispatch, pre-dispatch and ST PASA consistent with NEM security framework that incorporates the in-market reserve mechanism should deliver the security needs of the power system at an efficient cost.

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?	Yes
2) Are there any other issues related to the provision of synchronous inertia that have not been adequately described?	• Appropriate linkages with PFR have not been drawn. • Managing the integration of DER, a key driver in the displacement of synchronous inertia has not been considered.
3) What are stakeholders' views on the approach to considering the interaction between FFR and inertia in the NEM?	FFR and inertia need to be co-optimised and can be done so with the appropriate standards embedded in the Frequency Operating Standard (**FOS**). FFR and inertia perform the same function in reducing RoCoF, and this would be the logical starting point in considering a metric for these services. The volume of services required also needs to consider the impact of PFR.
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?	To an extent although the standard for managing frequency control during normal operation has not been defined. The FOS sets the boundaries for the Normal Operating Frequency Band but does not detail how frequency needs to be managed within that band. In the consultation process for PFR, stakeholders advocated for the need to determine a metric that represents what this is so that the level of the service (PFR) is efficient in meeting that level.
2) Are there any other issues related to frequency control during normal operation that have not been adequately described?	CS Energy believes that the rule changes here need to be assessed within a broader review of frequency control services and processes in the NEM. This review should be already underway via the FCFR and it would be useful for stakeholders to have more transparency over the status of this work. • Review the Market Ancillary Service Specification (**MASS**) to ensure that the provisions are clearly specified together with performance expectations. • Review the efficacy of AEMO systems in the delivery of regulation services in the NEM. • Greater transparency in the progress of the FCFR workplan. • The interdependency on potential in-market reserves that may also manage variability.
3) What are stakeholders' views on the proposed approach to reforming the process for the allocation of the costs of regulation services (Causer pays)?	CS Energy agrees with causer-pays in this context and this should be considered for operating reserves also.
4) Is the level of specification of regulation services in the NER fit for purpose as the power system transforms?	No. Given the challenges identified in the consultation paper and the consideration of operating reserves to manage the expected variability that will become a feature of normal operations, CS Energy would like to see regulation FCAS reviewed in this context to ensure it is expected to deliver what is needed in future. Regulation FCAS currently corrects small variability in power system

	frequency during each five-minute dispatch interval. Depending on how operating reserves are designed, this could be a duplication of some service, or represent inefficiencies in regulation FCAS. This latter service may need to become more flexible to better address the changing system dynamics. Additionally, the provisions in the MASS for regulation services do not specify what the enabled providers should provide. Recent increases in regulation amounts enabled has improved the frequency performance. This provides AEMO with the opportunity to analyse the outcomes and perform a cost/benefit to assess the value of the increase in regulation amounts which could inform this process.
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?	CS Energy agrees that with less inertia the RoCoF following contingency events will be larger and represents a greater operational risk. The challenge related to frameworks not incentivising market participants to reduce their potential impact on the need for frequency control services can be addressed via changes in the MASS of which CS Energy has been supportive. The changing complexity of the power system with the behaviour of distributed solar highlights the need for any system service mechanism to consider the impact of DER on the market and the associated allocation of risk and cost.
2) Are there any other issues related to frequency control following contingency events that have not been adequately described?	In its rule change request, Infigen raised the changing nature of credible events and new modes of failure, and this process needs to consider the broader requirements for frequency control following contingency events in a holistic manner.
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?	The process needs to include PFR together with FFR and inertia, review the existing eight FCAS markets to determine the appropriate number of FCAS markets. Outcomes and recommendations from this review would be required to be reconciled with a review and update of the MASS to ensure alignment of the processes.
4) Is the level of specification for contingency services in the NER fit for purpose as the power system transforms?	The level of specification for contingency services needs to be reviewed considering protected events and the emergence on indistinct contingency events. It will also need to provide clarity over the frameworks for procuring in-market reserves versus contingency FCAS.

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?	The consultation captures the key principles required to achieve the objective of efficiently utilising the capability of both established, as well as new and emerging technologies. CS Energy reasserts that the most efficient and inclusive approach would be facilitated by clear standards for services, whether operational, planning or reliability. This provides an agnostic signal across all timeframes and the associated operating guidelines can be flexible and adaptive to changing technology capabilities and system needs. Standards provide forward visibility and capture any risks of the evolving system. For example, grid forming inverters may evolve to provide system strength and should be incentivised to do so, however, it is unclear whether these technologies will be sufficient in assisting with re-energising the network during black start and load restoration. A standard should ensure that any potential gap is met in time.
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?	CS Energy agrees that the NEM needs to shift away from the current directed approach of system services as it is reactive in nature and contributes to uncertainty and increased costs. For most of the services, if appropriately valued, the industry would innovate to deliver the specified requirements with allocative efficiency. Where appropriate to the service, spot markets in the longer-term are the most efficient approach. While spot markets do not align with the investment timeframe, it utilises the commitment process and through optimisation should deliver allocative efficiencies. The reality is that spot markets in new services will provide strong signals for day to day dispatch but may not be strong enough in the near term to support an investment case in new assets. Investors may not invest in new assets based on potential system services spot markets five years from the date of a proposed financial investment decision, but they will operate once those assets exist to capture those spot prices. This would need consideration and should draw upon the *Essential System Services* MDI. The consultation paper outlined the hybrid approach of the United Kingdom and while CS Energy does not oppose the intent of this approach, caution needs to be applied to ensure layering doesn't cause inefficiencies. The UK established multiple market products in this hybridisation and has since greatly reduced the number of these as they were superfluous and inefficient. This flipflopping resulted in increasing investment uncertainty.

	CS Energy strongly supports that statement that "*reporting of market and system performance can improve transparency of these arrangements and provides information to market participants to guide more efficient operational and investment decisions*"[4]. Appropriate market information across all timeframes is essential to future investment as well as efficient operations. A key challenge to date for industry is that this information related to system services has been lacking in processes such as the Electricity Statement of Opoortunities and the ISP that are supposed to guide these decisions.
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? 2) What are stakeholders' views on the potential downsides of introducing arrangements for commitment of capability ahead of dispatch? 3) Are there alternative arrangements that can reduce the increasing uncertainty associated with power system operation in the NEM?	CS Energy disagrees with the discussion of aheadness and refers the AEMC to the AEC report. Ahead markets do not solve system security challenges, nor do they promote flexibility and innovation. An ahead market would transfer the risk to AEMO, and hence consumers. They would likely increase costs to the market and would not incentivise investment. Claims that there is a need for improved processes for scheduling are premature as they have not considered the coordination that an organised mechanism (spot or otherwise) delivers to the market once appropriate signals are in place. Any assessment of the adequacy of scheduling processes must be performed *after* mechanisms for security and reliability services are developed and must include justification of why this can't be achieved within the current frameworks, particularly if operating standards are amended to reflect the system needs. CS Energy attests that existing NEM processes can accommodate these scheduling requirements. With enhancements, AEMO systems covering the dispatch, pre-dispatch and ST PASA will manage efficient delivery of the system services. Confidence and certainty in the commitment and provision of essential system services would be underpinned by enforcement of the relevant Rule obligations and the provisions in the rebidding and technical parameters frameworks. These obligations provide a much stronger commitment incentive than ahead market arrangements. Through these processes, AEMO would be required to set the requirements and thresholds, be able to determine the quantity of essential services arising from the offers and bids and commitment decisions, and report headroom or shortfall in those services.
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?	CS Energy generally supports a user-pays approach though recognises that it may not be appropriate for all system services. Where mechanisms seek to provide incentives to minimise services such as frequency control, then some causer-pays approach may be relevant. With the emergence of potential

[4] AEMC, *Ibid*, p74

	new business models such as aggregators, DRSPs and large proportions of DER contributing to the need for system services, the AEMC may need to consider innovative and hybridised approaches to cost recovery.
2) In each case, how can the cost recovery arrangements be developed to lower the overall costs of the NEM?	It is difficult to provide a detailed response until the final proposals and rule changes are available for assessment. However, we seek to determine the appropriate balance between complexity and simplicity to ensure transparency and not to inadvertently erode the benefits and/or unjustifiably increase costs
Question 23: Section 9.4 – Implementation considerations	
1) What are the challenges or implications associated with implementing proposed arrangements discussed in this paper?	A key challenge will be the management of interrelatedness between the processes and potential adverse outcomes. This will be essential against the backdrop of the ESB 2025 program, and the AEMC will need to ensure that the proposals are assessed against a potential reform package not just the current Rules framework.
2) What are stakeholders' views on the prioritisation or staging of the reforms to address the issues discussed in this paper?	The development of a prioritisation list is an imperative to ensure that the workplan is staged in manner to deliver success. The most urgent steps are: a) Provide stakeholders with clarity over the integration of this process with the ESB 2025 program. b) Provide transparency of the progress to date of the FCFR work program. c) Initiate a review of operating standards and develop key metrics for all system and reliability services, and the necessary processes for the Reliability Panel oversight. d) Determine whether system strength and voltage are limited to contracted arrangements and progress solutions, particularly given the urgency. e) Bundle the other services and consider a holistic approach to an efficient and effective outcome.