OVEN MOUNTAIN PUMPED STORAGE

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13 August 2020

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via email: james.hyatt@aemc.gov.au

Dear James,

RE: System Services Rule Changes consultation response

OMPS welcomes the opportunity to provide feedback on the AEMC's consultation on a number of rule change requests regarding system services.

OMPS is developing the Oven Mountain Pumped Hydro Energy Storage project (Project) in NSW. This off river, closed loop scheme is of significant scale, providing 600MW and up to 12 hours of deep storage capacity. The Project will connect at Armidale substation on the NSW transmission backbone running through the New England Renewable Energy Zone (REZ) recently announced by the NSW Government. The Project boasts high head over a short distance which allows for a highly efficient and responsive scheme.

Numerous studies, plans and reports including AEMO's ISP, ISP Insights, and the NSW Electricity Strategy identify pumped hydro as a key technology to provide system services such as inertia and system strength to replace diminishing supplies. This is on top of the recognised low cost storage value of the technology providing much needed dispatchable capability to support energy reliability over intra and inter day durations.

OMPS is in the development stage of the Project and the views presented here are focused through the lens of providing clarity to development and investment entities. Pumped hydro energy storage projects are significant engineering developments and take considerable time and effort to bring to market.

The issues raised by the AEMC in its consultation touch upon many of the factors which can provide clarity on the value of bringing a pumped hydro energy storage project to market. These include:

- Explicitly valuing system services which are needed but have, to date, not been valued;
- Considering dispatchable reserve capacity to support energy reliability; and
- Encouraging competition to place downward pressure on the cost of system services.

OMPS raises the following themes in response to this consultation process, with responses to AEMC posed questions provided in Attachment A.

- **Value of Inertia** – OMPS supports efforts that value system services in a technology neutral way. We recognise the ability of fast frequency response (FFR) to support and enhance the effectiveness of inertia (physical and virtual) in providing system resilience. We also appreciate the intrinsic differences in the technologies with inertia providing instantaneous response to a contingent frequency event and FFR following after a short delay. Creating a market or mechanism that values these services (FFR and inertia) is required to ensure that development capital is applied to bringing appropriate solutions to address the need.

- **Competitive System Services** – Co-optimising in NEMDE may be a more efficient way of procuring system services as compared to contracting separately for each service. Facilities that offer multiple services, for example inertia and system strength, may be able to offer these more competitively together than as a single service. Co-optimising would also efficiently respond to changing system service needs over time.

  Such an approach could be a hybrid of TransGrid's and Hydro Tasmania's proposals where system strength quantities at locations are periodically set by the regional TNSP as NEMDE inputs allowing co-optimisation of system services with energy, ancillary services and constraints. In this way, each service can be valued and appropriate pricing signals be made regarding the need and location of new services to developers, investors and even unregulated TNSP businesses.

- **Dispatchable Reserve Capacity** – Much has been written on the need for additional dispatchable capacity in the market, and the increase in Lack of Reserve (LOR) notifications coupled with AEMO's use of the Reliability and Emergency Reserve Trader (RERT) recently supports this. The introduction of an in-market mechanism to secure dispatchable reserve capacity appears warranted and at the very least provides price competition to the RERT. From OMPS' perspective, a mechanism for dispatchable reserve capacity provides a signal on the value of dispatchable generation and supports development of the Project.

- **Actionable Signals** – Pricing signals themselves may not be sufficient to trigger market responses. In deciding whether to value services, consideration should also be made as to the bankability of related revenue streams; depth of any market based solutions; counterparties and their ability to contract; and any non-market contract lengths.

- **Early Market Establishment Required** – Since the inaugural ISP, the notional retirement schedule of coal fired power stations has been clear and consistent. Should market based solutions be considered for system services and reserve dispatchable capacity, early establishment of these services markets is required to provide sufficient time for participants to respond with competitive and viable solutions.

- **Consolidation of Reforms** – We appreciate the efforts of the AEMC in consolidating the consultation process for the six rule change request proposals, which eases the burden on stakeholder engagement. With a large influx of regulatory change currently underway, continued efforts to consolidate, coordinate and streamline further reform will help to achieve efficient, transparent and hopefully simple outcomes.

We would welcome the opportunity to discuss with you further regarding the AEMC's work on system services in general and the consultation in particular.

Sincerely,

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Attachment 1: Responses to AEMC questions

Q1.1. What are stakeholders' views on how the rule change processes should be integrated with ESB and AEMO work programs?

The AEMC has recognised the high rate of change in the industry with multiple bodies undertaking multiple actions as supply and demand changes. This goes beyond just AEMO and ESB, where Governments and NSP's are also actively working in their own way to facilitate change. Care is needed to ensure that coordination between the bodies is maintained and unintended adverse outcomes are minimised.

The ESB's Post 2025 Market Design work appears to be an area that is highly relevant to the proposed rule changes and in this way care should be taken to ensure that any work into the rule changes aligns with the thinking of the Post 2025 Market Design.

Q1.2. Are there any additional processes that should be closely considered by the Commission when progressing these rule change requests?

The AEMC is in a better place to be across the various workstreams undertaken by the various bodies and how they inter-relate.

Q2.1. Do stakeholders have any comments on the proposed timetable for the system services rule changes?

The timetable seems reasonable and provides an opportunity for further consultation and coordination noting that only immediate actions timeframes have been identified at this stage.

Q3.1. Do stakeholders agree with the AEMC's approach to grouping the rule changes, at least for initial consideration?

There is a lot of materials to cover as a market participant, and the AEMC's efforts to consolidate, even if only the consultation step, is greatly appreciated.

Q3.2. Do stakeholders believe that Figure 3.1 captures the key issues to be considered for each rule change in each time frame?

From a project development perspective, the appropriate timeframe in Figure 3.1 is the Investment timeframe, although the other timeframes guide the development solution. In this regard, we would look to better understand what consideration is provided to bankability of solutions.

If a new market (e.g. system strength) is considered – who is the counterparty and what is their ability to offer longer term contracts (e.g. hedges)? Greater confidence in bankable products increases the likelihood of competition to service those products and ensure cost effectiveness.

Q3.3. Do stakeholders have views on whether/which services should be procured in certain time frames and not others?

We're not clear on the volume, location, and nature of the needs to be addressed.

From a developer standpoint, establishment of a need and pricing earier provides signalling to ensure a solution is developed, permitted and ready in time for the actual need.

Q4.1. 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?

The system services objective appears appropriate.

Q5.1. Do stakeholders agree with the '4Ps' service design framework being used to design these rule changes?

The 4Ps service design framework appears appropriate.

Q6.1. Do stakeholders agree the principles proposed for assessing the rule change requests are appropriate? If not, which should be amended, excluded or added?

The assessment principles appear appropriate.

Q7.1. What are stakeholders' views on the issues raised by the Infigen in its rule change request, Fast frequency response market ancillary service?

FFR is largely a technology specific product that has shown to be effective internationally, particularly in regulation services.

In relation to a contingency responses, FFR has been shown to support and enhance the effectiveness of inertia. A technology neutral approach would be to develop a regime that values all viable solutions within the post-contingency response window to 6 seconds. The AEMC rightly recognises that this has to date been provided by synchronous inertia without value.

Q7.2. 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?

No comment

Q7.3. What are stakeholders' views on if there are any other issues or concerns that stakeholders have in relation to frequency control in the NEM as levels of synchronous inertia decline?

While not being able to provide the critical instantaneous response, FFR can provide valuable frequency dip suppression support.

Due to RoCoF detection physics, FFR service offering necessarily includes a time delay between any contingent event and delivery of the service. In this way it is widely recognised that only inertia (physical or virtual) can provide the critical instantaneous response immediately after a contingent event. FFR is able to enhance the efficacy of inertia, not replace it. Valuing inertia may promote more supply to replace retiring synchronous plant. FFR can be a valuable tool in enhancing inertia.

Q7.4. 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?

There are a number of schemes aimed at responding to contingent events, for example ElectraNet's System Integrity Protection Scheme (SIPS). These act on protection signals to trigger responses and in this way respond to pre-defined contingent events.

As the AEMC notes, the number of non-credible contingency events have increased dramatically recently that limits the flexibility of a SIPS style scheme to respond. A greater focus on inertia would seem prudent to provide needed system security.

Q7.5. 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?

There is no reason to believe that the bidding, enabling and provision of FFR would be challenged by participation in a 5-minute market. This could be broadened to include inertia as well.

Q7.6. Do stakeholders consider Infigen's proposal would provide adequate pricing signals to drive efficient investment in FFR capability in the NEM?

The establishment of a new market for FFR will facilitate price discovery. Challenges include time needed to gain confidence in prices, and whether simply having a market is sufficient to 'bank' projects.

Q7.7. What are stakeholders' views on, if introduced, how the costs associated with any new FFR market ancillary services should be allocated?

Consistent with the principle outlined in the Section 4.4 of the consultation, it seems the best allocation is to the party causing the contingency. This is undertaken in the Causer Pays for other FCAS payments, although the methodology is poorly designed.

Q7.8. What do stakeholders consider to be the likely costs associated with establishing two new ancillary service markets for FFR in the NEM?

No comments

Q7.9. Would are stakeholders' views on how the proposed solution may result in any substantial adverse or unintended consequences in the NEM?

The Infigen service proposes to commence at 500ms and extend to 6 seconds, allowing transition to the 6 second contingency service. The current causer pays data is collected at 4 second intervals. At first glance, it seems that a significant increase in data collection and transport would be required to facilitate this service, potentially increasing the cost of service.

Q7.10. 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?

Per Q7.1, FFR is one solution to a contingency response. The current and gold-standard solution is inertia, which is currently not being valued. Establishment of an FFR payment without similarly recognising other solutions may skew the market. Care should be taken to ensure valuing all solutions is made to ensure neutrality and efficiency.

Q8.1. Do stakeholders agree with Infigen that tight capacity conditions and increasing uncertainty in market outcomes are problems that an operating reserve would address?

TransGrid's 2019 and 2020 Transmission Annual Planning Reports highlight an increase in lack of reserve events (LOR) in NSW which would support Infigen's view of tightening capacity during peak demand.

AEMO's projections of unserved energy captures increased dispatchable generator unreliability indicating that capacity constraints may be a continued feature until these plant are replaced with newer plant with increased reliability.

Q8.2. Are there alternative solutions that could be considered to address tight capacity conditions and increasing uncertainty in market outcomes?

Outside the Retailer Reliability Obligation, normal market hedging, and the RERT, encouraging more/new generation/load management seems appropriate.

Q8.3. 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?

The proposal is effectively a market driven capacity payment, and should provide price discovery as the market settles. From a developer perspective, a stable pricing signal will encourage solution development and permitting.

Q8.4. How do stakeholders think separate operating reserves arrangements would affect available capacity in the spot, contracts and FCAS markets now and in the future?

No comment

Q8.5. How do stakeholders think separate operating reserves arrangements would affect prices in the spot, contracts and FCAS markets now and in the future?

No comment

Q8.6. 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?

No comment

Q8.7. What are the factors that should be considered when seeking to set and procure efficient levels of operating reserve?

No comment

Q8.8. Would Infigen's proposed operating reserve market result in any substantial adverse or unintended consequences in the NEM?

No comment

Q8.9. What are the costs associated with establishing an operating reserve market in the NEM? If introduced, how should these costs be allocated?

No comment

Q8.10. What kind of incentive/penalty arrangements would be necessary to be confident the operating reserves procured are available when needed?

No comment

Q9.1. 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?

The AER's quarterly regional offers by price bands appear to support this statement with reduced offer volumes between $0 and $5,000/MWh. This is particularly pronounced in South Australia but visible in other regions except perhaps Tasmania.

Q9.2. 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?

The nearest FCAS products analogous to the proposal are regulation FCAS (raise/lower), which are procured on a 5 minute basis. The regulation FCAS is intended to match the supply/demand balance over a dispatch interval. Given there are 6 dispatch intervals over the proposed 30 minute window proposed, it is not clear the interaction/delineation of a ramping product relative to a dispatch product.

The increased price volatility arising from high levels of ramp rate is a pricing signal for investment. Dulling the signal may delay investment response.

Where ramping of plant impacts on system security, constraints may be applied to ensure reliability.

Q9.3. 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?

Per Q9.2, it is not clear what signal is being provided as there already exists a 5 minute dispatch market. As the market moves to a 5 minute settlement next year, greater granularity on the value of faster dispatch generation will become clearer and improve pricing signalling accordingly.

Q9.4. 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?

A 30 minute ramping product has the potential to complicate the various existing markets and increase NEMDE complexity in enabling and dispatching such products.

Q9.5. 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?

How a 30 minute ramping product would interact with existing market participants is unclear. It is possible to see a scenario where the dispatched generation during a settlement period is a conflation of dispatched energy (wholesale market settlement) and 30 minute ramping product (possible causer pays recovery).

Q9.6. How could the design of a ramping FCAS product (e.g. criteria for eligible capacity) support competitive outcomes both energy and FCAS markets?

How a ramping product could support competitive outcomes is not immediately clear.

Q9.7. What are the factors that should be considered when seeking to set and procure efficient levels of ramping services?

No comment

Q9.8. Would Delta's proposed new 30-minute raise and lower FCAS products result in any substantial adverse or unintended consequences in the NEM?

A 30 minute ramping product may provide an avenue for generators with low rate of change to continue in the market without investing (directly or via contract) in technologies that can increase their ramping rate.

This seems contradictory to the market evolution, such as 5 minute settlement periods.

Q9.9. 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?

No comment

Q10.1. 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?

Without commenting on the cause of any reserve withdrawal, we agree that there is an increase in AEMO issued Lack of Reserve and this increase is documented in TransGrid's 2019 and 2020 Transmission Annual Planning Reports. AEMO's ESOO also highlighted increasing reliability related forced outages increasing unserved energy through their forecast horizons after the retirement of Liddell power station.

Similarly diminishing system service volumes are well documented.

Q10.2. 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?

The Retailer Reliability Obligation is a mechanism that seeks to ensure energy reliability via AEMO forecasts and looks at multi-year time horizons. Traditionally market exposed load participants including retailers would typically seek to hedge their exposure, thereby ensuring capacity.

The increase in LOR events coupled with AEMO's continued use of RERT arrangements show that greater market participation is required to provide more reliability capacity. In this way, a reserve capacity makes sense.

Consistent with Hydro Tasmania's request, system services may be separated to allow greater market participation, but with both system services and reserve capacities being co-optimised to ensure efficient delivery of these services.

Q10.3. Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in reserves and system services?

A dispatchable reserve capacity market would provide pricing signals for dispatchable generation and encourage investment in these services.

Similarly a system services market would provide pricing signals to encourage investment in these system services.

Q10.4. 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?

The high market price cap provides a signal to low utilisation peaking plant to participate in the market. Providing a dispatchable reserve capacity market may reduce the speculative nature of peaking investment and facilitate greater capacity.

Having a system services capacity market would act in a similar way, encouraging investment into these technologies to be ready when needed.

Q10.5. How do stakeholders think Delta's capacity commitment mechanism would affect prices in the spot, contracts and FCAS markets now and in the future?

Having more reserve capacity spare may provide competitive pressure on actual spot markets. The high market price cap provides a signal to low utilisation peaking plant to participate in the market. Providing a reserve capacity market may reduce the speculative nature of peaking investment, allowing participation at lower costs and thereby increase competition.

Having a system services capacity market would act in a similar way, encouraging investment into these technologies to be ready when needed. Having sufficient system services acts to reduce the need to curtail lower cost energy capacity from the market and thereby enhancing available generation.

Q10.6. How would a capacity commitment mechanism and payment affect entry, exit and competition in the NEM over the short and long term?

Reserve capacity payments may support a participant to stay in the market longer than without any payments. However, having an established market will encourage more efficient participants to enter the market and in time compete with established parties.

System services capacity payments may also similarly extend a participant’s time in the market, however these services are not currently valued yet are needed. Examples exist where insufficient system services have led to curtailment of lower cost renewable generation in the NEM. Establishing a system services capacity market will encourage efficient participants to enter the market and in time compete with established parties.

Q10.7. What are the factors that should be considered when deciding how much capacity to commit ahead of time?

The practice of establishing reserve capacity requirements is well established and operated by AEMO.

Regarding system services capacity requirements, TransGrid’s proposal of regional TNSP’s setting system services targets locationally in the NEM appears sensible.

Q10.8. Would Delta's proposed capacity commitment mechanism result in any substantial adverse or unintended consequences in the NEM?

Combining reserve capacity and system services narrows the volume of available suppliers. Further, any asymmetry between required system services volumes and reserve capacity volumes may require over subscription of one service.

Separating reserve and system services allows for greater participation. Co-optimising the two services would ensure efficient supply of capacity of each service.

Q10.9. What are the costs associated with establishing a capacity commitment mechanism in the NEM? If introduced, how should these costs be allocated?

No comment

Q10.10. 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?

No comment

Q11.1. Do stakeholders consider this rule change proposal presents a viable model for the provision synchronous services?

At a high level, it does seem to present a model that could be worked to be effective.

Subject to being able to develop a service definition for elements such as system strength (fault current seems to be a commonly used proxy), then it seems that volumes and locations could be assessed through power system planning and abstracted into NEMDE. A mechanism based on open circuit breakers may not be sufficient to drive competition and encourage new investment.

Q11.1.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?

The proposed system seeks to place a value on items that have been delivered to date as a by-product. As identified by Infigen, the provision of the synchronous services are important enough to consider alternate solutions. So it makes sense that providing a market for synchronous services would allow volume targets to be established and the market to respond and compete accordingly.

Q11.1.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?

Using volume targets, yes the model could drive system services above essential levels. The model also allows for the participation of network service providers, through their unregulated business units.

Q11.2. 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 would these impacts be?

It is unclear the volume of synchronous services required, and whether a market would be deep enough to provide revenue projection sufficient for bankability.

An alternative approach could be looking at who pays for the service cost, and whether such a consideration would allow hedge contracting to support revenue streams to fund such assets.

Q11.3. Would the proposed model set out in the rule change request efficiently price and allocate costs for synchronous services in the NEM ?

Yes

Q11.4. Do stakeholders consider the model set out in the rule change request would be capable of sending price signals sufficient to encourage new investment in synchronous capacity?

In time, as the market settles, if the service is valued then yes. The Hydro Tasmania proposal could work in complement to the TransGrid proposal, providing a way for network and non-network solutions to compete fairly.

Q11.5. Do stakeholders consider the rule change provides an appropriate incentive mechanism for existing synchronous generators to make operational decisions to provide synchronous services ?

Yes, in response to demand.

Q11.6. Do stakeholders consider the rule change provides the appropriate locational signals for the provision of synchronous generators to provide synchronous services ?

Location of service must carefully be considered in design. A locational adjustment factor approximating the TransGrid nodal concept may assist in this regard.

Q11.7. What do stakeholders see as the primary opportunities / limitations of the mechanism as proposed by Hydro Tasmania?

Hydro Tasmania have put forward a good draft for a method to value synchronous services. Multiple studies and numerous constraint equations have demonstrated their need to system security. Introducing a market mechanism has the ability to provide transparency for valuing these services as well as market signals of where to locate future synchronous assets.

Q11.8. Would the model proposed in the rule change request enable effective competition in the market for the provision of synchronous services?

With some modifications to account for service definition and location, yes.

Q11.9. 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?

No suggestions at this stage.

Q12.1. Do stakeholders consider that TransGrid's approach address all issues related to system strength currently experienced in the NEM?

Yes, TransGrid's approach does address issues related to system strength through a centralised approach.

Q12.2. Do stakeholders consider that a system strength planning standard met by TNSPs would effectively and pro-actively deliver adequate system strength?

Possibly. The proposal increases the TNSP's role in the success or otherwise of new projects connecting to the NEM. The ability to pro-actively deliver remediation will be influenced by existing TNSP workload.

Q12.3. Do stakeholders consider TransGrid's proposal will provide useful and timely locational and financial signals to new entrants?

The proposal is focused primarily on new generation development rather than all new entrants and responds to recently seen challenges connecting new generation. The proposal does not provide incentive for new system strength provider entrants.

Q12.4. Do stakeholders agree that the 'do no harm' obligations should be removed?

No. While we agree with TransGrid's observation to reduce the number of bespoke synchronous condensers, we believe the solution should be market driven. We also believe that a market solution could include an optimised TNSP solution to the market. Removing the 'do no harm' requirements also removes the ability for efficient market solutions to solve the problem.

Q12.4.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?

Providing a system services value rather than simply a performance requirement will likely change new entrant perceptions of the value of new equipment and may allow greater service collaboration (e.g. contracting). For example, a private synchronous condenser owner may be more inclined to sell services into a market than directly to a competitor – while in effect it is the same.

Q12.5. What are stakeholder's views regarding generators' being required to make a financial contribution for provision of system strength services?

We agree with the concept, but under a regime that values system services as a market product – similar to the Hydro Tasmania proposal. This would encourage generators to source efficient solutions to be competitive. A centralised regime may not encourage innovation or efficiency.

Q12.6. 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?

On face value, and not being privy to any asset business case, the transfer of any entity's assets should be a commercial decision to be considered by the parties involved.

Q12.7. Would the proposed, TNSP-led solution to system strength result in any adverse or unintended consequences for market participants in the NEM?

As a TNSP-led solution would most likely involve a TNSP scope and design, competition would be limited to asset delivery into the regulated (or non-regulated) asset base. It is difficult to see how items like design innovation, cost of capital advantages and non-market solutions could be incorporated into the proposal.

As a TNSP-led solution effectively enshrines zero value for system services, it effectively discourages projects to develop system services to replace retiring generators. A market based approach that provides a value for the services allows the market and TNSP's to compete for the most efficient solution.

Q13.1. 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?

No comment. This is better left to power system engineers.

Q13.2. If not, are there other components of system strength that the AEMC should include?

No comment.

Q13.3. 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?

This is better left to power system engineers. We do observe that fault current levels have been used, even as a proxy, for system strength in various reports and connection process. Fault current levels may provide a simple method for defining specifications in the interim.

Q14.1. 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?

A hybrid approach would be preferable. AEMO and incumbent TNSPs would provide quantified system strength need including locational and temporal variations. This would then be co-optimised per Hydro Tasmania's approach in NEMDE.

Q14.2. Do stakeholders consider the decentralised, market-based model proposed by HydroTasmania is the preferable option for providing system strength above the essential levels required for secure operation?

A hybrid approach would be preferable. AEMO and incumbent TNSPs would provide quantified system strength need including locational and temporal variations. This would then be co-optimised per Hydro Tasmania's approach in NEMDE.

Q14.3. Could a hybrid of these models be used to deliver system strength above the minimum?

Yes, where the NEMDE targets drive pricing outcomes and signals to the market on where investment is needed.

Q14.4. What do stakeholders perceive to be the strengths and weaknesses of each model?

The TransGrid proposal levers the system planner strength of quantifying the minimum system strength requirements locationally through the NEM.

The Hydro Tasmania approach provides the service valuation and allows technology neutral solutions to participate and compete. Further, the market is able to respond to changes in system strength volumes requirements over time.

Q14.5. Do stakeholders consider there are other, alternative models for delivering system strength above the minimum levels required for secure operation?

While the need for system strength has been published widely, the magnitude of the need isn't clear. If there is insufficient volume to justify a market approach, perhaps an auction process may suit.

Q14.6. 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?

Having a market based solution that utilises system strength targets lends itself to revising those targets over time. This allows the market respond to increased targets efficiently.

Having system strengths established above minimum levels would benefit rapid deployment of inverter-based assets such as solar, wind, and battery storage.

Q15.1. 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?

Available dispatchable reserves are diminishing with the energy transition and the timing of peak demand is changing both in time of day and duration. These changes appear to impact business cases of a number of dispatchable generators. Introducing an explicit in-market reserve arrangement may assist AEMO's confidence on reserves being available, and likewise the generator of having costs recovered.

Q15.2. 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?

AEMO's continued use of the RERT has demonstrated a need to have dispatchable capacity (generation or demand response) reserves available. At a minimum an explicit in-market reserve process would provide a value test for AEMO's reserves procurement.

Q15.3. 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?

An explicit in-market reserve mechanism may bias towards supporting existing thermal generation and potentially dampen market signals for new flexible rapid dispatchable generation.

Q15.4. Do stakeholders' think there to be an explicit need for a capacity commitment mechanism as proposed by Delta? Do stakeholders' think this as a separate need to an in-market reserve service?

AEMO's use of RERT suggests a need.

Q16.1. 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?

Co-optimising for reliability and security appears achievable via a mechanism similar to Hydro Tasmania's proposal and doing so should maximise market competition for both of these services.

Q16.2. How do stakeholders' think 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?

This may be best dealt with by the Post 2025 market design work under way.

Q16.3. How do stakeholders' think 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?

This may be best dealt with by the Post 2025 market design work under way.

Q17.1. Do stakeholders consider that the issues relating to declining levels of synchronous inertia have been adequately and accurately described?

Yes, particularly the observation around linkage of inertia and system strength needing to be considered together rather than separately.

Q17.2. Are there any other issues related to the provision of synchronous inertia that have not been adequately described?

No

Q17.3. What are stakeholders views on the approach to considering the interaction between FFR and inertia in the NEM?

FFR is a useful tool to enhance the primary role of inertia (both physical and virtual) in providing system resilience. They play different but very related roles. Both services fundamentally need to be valued to ensure signals to invest in these services exist.

The challenge will be in co-optimising for system strength, inertia and FFR. This however is achievable.

Q18.1. Do stakeholders consider that the issues relating to frequency control during normal operation have been adequately and accurately described?

No comment

Q18.2. Are there any other issues related to frequency control during normal operation that have not been adequately described?

No comment

Q18.3. What are stakeholder views on the proposed approach to reforming the process for the allocation of the costs of regulation services (Causer pays)?

These changes are overdue. Getting the causer pays mechanism to better reflect the actual causer contribution to an issue will allow the use of similar mechanisms to other services and improve service efficiencies. It also allows the causer to proactively mitigate their exposure through operational management.

Q18.4. Is the level of specification of regulations services in the NER fit for purpose as the power system transforms?

No comment

Q19.1. Do stakeholders consider that the issues relating to frequency control following contingency events have been adequately and accurately described?

Yes

Q19.2. Are there any other issues related to frequency control following contingency events that have not been adequately described?

No comment

Q19.3. 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?

We believe that inertia should be valued and rewarded to encourage investment in these plant.

Q19.4. Is the level of specification for contingency services in the NER fit for purpose as the power system transforms?

No comment

Q20.1. 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?

Valuing services such as inertia which are utilised and relied upon would assist in ensuring established capacity is available as well as encouraging new capacity.

A challenge for emerging technologies is the reliance of these technologies on strong systems. A contingent event may impact the strength of a network where these emerging technologies reside, potentially limiting their contribution. Co-optimising to ensure not only the volume of response but also the ability to rely on them is needed.

Q20.2. Do stakeholders have any initial thoughts on how the arrangements for system services can be best coordinated over dispatch, commitment and investment time frames?

A hybrid model of Hydro Tasmania's and TransGrid's rule change requests which introduces a market for system services provides for this.

The centralised planning element that forecasts and sets system services levels targets and locations provides investment signals. Market bidding for the supply of services provides commitment and allows dispatch.

Q21.1. Do stakeholders agree with the characterisation of arrangements for aheadness and commitment, including the potential benefits?

Yes

Q21.2. What are stakeholders' views on the potential downsides of introducing arrangements for commitment of capability ahead of dispatch?

No comment

Q21.3. Are there alternative arrangements that can reduce the increasing uncertainty associated with power system operation in the NEM?

No comment

Q22.1. What are stakeholders' views on the appropriate approach to cost recovery for each of the system services discussed in this paper?

Careful thought needs to be had regarding the reason for system services pricing signals. If an intent is to encourage the development of more services then consideration on how a revenue stream may be bankable should also be made. This could be through allocating the costs to those able to hedge risk, or introducing a transition period of price underwriting to ensure timely investment while the market develops.

Q22.2. In each case, how can the cost recovery arrangements be developed to lower the overall costs of the NEM?

In general a cost recovery mechanism which encourages multiple providers to compete places downward pressure on service costs.

Q23.1. What are the challenges or implications associated with implementing proposed arrangements discussed in this paper?

A key challenge is the integration with multiple workstreams variously seeking to address similar issues. Simplification and streamlining of similar processes and coordination with allied mechanisms (e.g. load shedding) will go a long way to improving efficiency and transparency.

Q23.2. What are stakeholders views on the prioritisation or staging of the reforms to address the issues discussed in this paper?

Significant market movements have occurred with the closure of Hazelwood and the closure of Liddell and other thermal generation is rapidly nearing. Projects to supply replacement or substitution services takes many years to develop and progress through planning, design, connection, etc. These development activities come at a cost. In order to ensure that good solutions are forthcoming in time for their need, early and clear signs to the economics are needed.