6 February 2025

Ms Anna Collyer

Chair

Australian Energy Market Commission

GPO Box 2603

Sydney NSW 2001

Electronic Lodgement: ERC0339

Dear Anna,

AEMC Directions Paper Efficient Provision of Inertia

Energy Networks Australia (ENA) welcomes the opportunity to make this submission in response to the Australian Energy Market Commission's (AEMC) Directions Paper Efficient provision of inertia.

ENA represents Australia's electricity transmission and distribution and gas distribution networks. Our members provide more than 16 million electricity and gas connections to almost every home and business across Australia. This submission is on behalf of transmission members.

Overall, while ENA is supportive of the direction the AEMC has described in the Direction Paper we consider that further work is required to robustly demonstrate an overall material benefit. ENA considers the priority at this time should be for existing system strength and minimum inertia procurement activities to be completed and their operational arrangements to be bedded down. Until these arrangements are further progressed the future level of additional inertia demand remains too uncertain to confidently embark on a further round of complex reforms.

In summary ENA supports,

- The proposed delineation between minimum inertia demand and additional inertia demand so far as it relates to planning timeframes and long-term procurement activities. The AEMC should ensure any delineation between minimum and additional inertia demand aligns with AEMO's approach to setting required inertia levels under the current framework;
- The AEMC view that minimum inertia demand is still best met through procurement under long-term contract arrangements;
- Mandating, at least in the near term, that a substantial percentage of minimum inertia demand must be met by synchronous plant;
- Further analysis of the costs and benefits of allowing for future increases in the size of the largest credible contingency, noting that any increase will likely also increase the impact of non-credible contingency events;
- Further reform of the Chapter 5 plant modification processes to allow TNSPs and AEMO to oversee reasonable periodic retuning of control settings on existing plant, including grid forming inverters, to optimise overall power system technical performance, without reopening registered performance standards. This should not be limited to just retuning of inertial

responses, but be of broader application to efficiently meet a variety of power system standards; and

- Further consideration of staged implementation of any operational procurement mechanism, such as co-optimised dispatch using contracted offers for inertia, noting the potential complexities of implementation. This could allow some of the benefits of operational procurement to be realised without committing to significant development of participants bidding systems.

ENA considers the establishment of any new market mechanisms for the procurement of additional inertia requires significant further work and analysis that reflect future technologies and inertia demand. In particular:

- The expected future demand for additional inertia appears highly uncertain at this time. TNSPs, as System Strength and Inertia Service Providers, are currently prioritising the procurement of system strength requirements as well as minimum inertia requirements – the latter under the recently introduced Improving Security Framework (ISF) rule changes. Once these initial procurement processes are completed and their operational arrangements bedded down the expected demand for additional inertia can be more clearly understood.

- The expected benefits of introducing an operational procurement mechanism appear modest, based on the analysis in the Houston Kemp report. The assessed benefits of previous market reform initiatives analysed by the AEMC have been substantially greater and have provided stakeholders with a degree of confidence that overall benefits will result even if implementation costs are greater than originally forecast. Given the uncertainty about future additional inertia demand noted above there remains a risk that positive net benefits will not eventuate

- There is a need for further investigation of the potential implementation costs for transmission networks and other stakeholders, including potential inertia providers. In particular, clarification of the roles and responsibilities of various parties where there are two different procurement mechanisms may be challenging. Additional costs could also result from implementing a mechanism that procures additional inertia from parties that are already contracted for the provision of minimum inertia.

ENA is concerned that the complexities of operationalising the proposed delineation between minimum inertia demand and additional inertia demand is underestimated. The development of the necessary tools to implement an efficient spot market for additional inertia could be complex and ENA supports further consultation and collaboration with AEMO regarding the ability to deliver the real-time system needed to support this market.

ENA remains concerned about cost recovery arrangements where AEMO makes operational decisions in relation to power system security resources procured by TNSPs and that result in highly variable and volatile cash-flows for TNSPs. TNSP cost recovery through regulated annual transmission prices is well suited to large fixed-cost, long-term contracting arrangements with service providers. ENA considers that the costs of service provision that are highly changeable and that are based on market and power system conditions that interact with spot market dispatch and pricing outcomes are better suited to recovery through AEMO's weekly settlement processes.

ENA also has reservations about creating different eligibility criteria between inertia provided through long-term contracts and inertia provided through operational procurement, as this could create inefficiencies in one or other of the two markets. If not carefully thought through this could lead to wealth transfers from electricity consumers to inertia providers and undermine the benefits of operational procurement.

ENA provides further detail on these key points in Attachment A.

ENA looks forward to working with the AEMC as it works to develop draft rules. In the meantime, if you would like to discuss this submission, please contact Verity Watson (vwatson@energynetworks.com.au) in the first instance.

Yours sincerely

Dominique van den Berg
Chief Executive Officer

Attachment A

1. Characterising inertia requirements

The AEMC has proposed to separate the overall requirement for inertia into two components:

- Minimum inertia demand – this is the quantity and distribution of inertia required for the secure operation of the power system; and
- Additional inertia demand – this is any additional inertia above the minimum inertia demand that is able to reduce dispatch costs by decreasing some FCAS requirements or alleviating other binding constraints on dispatch.

Under the current inertia framework AEMO identifies the required quantity and distribution of inertia to meet the minimum inertia demand over a ten-year planning outlook through the annual Inertia Report. Inertia Service Providers, being the TNSP for the inertia sub-network or the jurisdictional planning body where there is more than one TNSP, then procure the required quantity of inertia and make that available to AEMO to meet the minimum inertia requirements in real-time.

While this conceptual framework can work in the planning timeframe it is likely to be very complex to operationalise in real-time. The actual minimum inertia requirement in real-time will depend on the bids and offers of market participants and the dispatch outcomes in both energy and FCAS markets. As noted by the AEMC it is likely to be highly variable and may prove challenging for AEMO for manage and finely tune in operational timeframes.

While ENA agrees with the AEMC's characterisation of inertia requirement as comprising two components, being a minimum inertia demand and an additional inertia demand, we consider it can only be practically applied in planning timeframes at this stage.

2. Procurement of minimum inertia demand

The Houston Kemp two-stage economic analysis concluded that minimum inertia demand does have some of the economic characteristics that would support operational procurement. However, given the very high costs of undersupply, due to placing the secure operation of the power system at risk and potential for large scale power system collapse, the AEMC consider that operational procurement is not currently suitable.

ENA agrees with the AEMC's view that long-term procurement frameworks are currently the most suitable procurement mechanism to meet minimum inertia demand. These long-term procurement mechanisms could include contracting with third party providers on inertia, such as existing or new synchronous plant, or direct investment by TNSPs in new synchronous condensers.

Given the criticality of minimum inertia demand to the secure and reliable operation of the power system ENA considers great weight should be given to the procurement of sources of inertia that are well proven in meeting the inertia needs of the power system. As described in the Directions Paper inertia acts to stabilize the power system following power system frequency disturbances by instantaneously transferring energy to or from the power system as part of the conservation of energy.

For synchronous plant this instantaneous energy transfer mechanism is inherent in the electro-magnetic coupling of a large rotating mass to the power system and is not reliant on any special control mechanisms or a particular configuration of the plant. Even a generator without a frequency-responsive governor system will still provide its inherent inertial response to a power system disturbance.

While grid forming inverters are a promising new technology their ability to support the provision of inertia relies on a suitable store of energy behind the inverter, which is able to discharge or charge consistent with the real-time needs of the power system. In most instances this will require battery systems with sufficient headroom or footroom to (nearly) instantaneously transfer the required energy to or from the power system. It also requires a suitably configured control system to initiate a synthetic inertial response.

As the application of grid forming inverter technology for the provision of an inertial response is still developing and relies on the correct operation of complex control systems, ENA considers it is too soon to rely on this technology to meet the minimum inertia demands of the NEM. The costs to electricity consumers from a major power system disturbance should the advanced control systems fail to respond appropriately would be significant. For these reasons ENA supports mandating that at least a substantial percentage of the minimum inertia demand must be procured from synchronous plant – which includes synchronous generators, synchronous condensers and synchronous loads such as large spot loads. ENA remains cautiously optimistic about the potential role of synthetic inertia and its future contribution to meeting some part of the minimum inertia demand.

3. Maximum impact of credible contingencies

The Directions Paper has flagged the potential for the size of the largest credible contingency in the NEM to increase in the future from the current maximum of 744 MW for trip of the Kogan Creek generator. In particular, large renewable energy zones or offshore wind farms may create larger credible contingencies, depending on how their connections to the transmission network are configured. In addition, new large loads such as hydrogen production facilities could increase the size of the largest credible load contingency.

Allowing for increases in the size of credible contingencies may be technically possible if additional inertia and FCAS can be economically procured, and this may reduce investment costs for both new plant connections and shared network augmentations. However, ENA cautions that this must be weighed against the risk that the impact of non-credible contingency events will likely also increase as a result. This could increase the risk of large-scale power system disturbances and outweigh the benefits that might otherwise be realised.

4. Retuning controls to optimise performance

The increasing penetration of inverter-based resources (IBR) with advanced digital control systems onto the power system provides great opportunities to extend the technical limits of the power system beyond what was historically possible. TNSPs are currently able to retune control settings on their own dynamic reactive power equipment such as SVCs and STATCOMs to adapt to changing power system conditions.

However, for third party equipment that connects to the transmission network the existing processes in Chapter 5 of the NER constrain the ability to undertake similar retuning. As noted in the Directions Paper, retuning of a grid-forming inverter to change the inertia response will trigger a clause 5.3.9 process to change registered performance standards for the plant. ENA considers there would be material benefits in reforming the Chapter 5 processes to allow TNSPs and AEMO to oversee reasonable periodic retuning of control settings of all plant to optimise overall power system performance, without triggering a clause 5.3.9 process.

To be clear, such a reform to Chapter 5 would not permit ad-hoc changes to control settings by plant owners and would need to be under the control of AEMO and the host TNSP.

5. Possible new operational procurement mechanism

Based on the analysis undertaken by Houston Kemp the AEMC has suggested that there may be an economic case for establishing a new operational procurement mechanism for additional inertia. This prima-facie case is based on the following elements:

- Additional inertia has economic characteristics that are better suited to operational procurement than minimum inertia. In particular, an under-supply of additional inertia does not create risks to power system security, but does create an economic cost through constraints on dispatch;
- The benefits of procurement of additional inertia (by whatever mechanism) derive primarily from reducing the costs of other FCAS procurement. Further benefits could be derived from an ability to alleviate inertia constraints in Tasmania and South Australia as well as efficiently address unplanned shortfalls in minimum inertia in real-time; and
- An estimated net present cost of establishing a stand-alone spot market for additional inertia of $20 million to $50 million over ten years.

ENA notes that Houston Kemp's estimates of benefits that additional inertia has on the cost of procuring other FCAS is highly dependent on the relative cost of the two products. It is only when the variable cost of additional inertia is low ($0.04/MWs/hour) and the cost of the fast frequency response FCAS product increases from its current levels that any measurable benefits are estimated to accrue.

Houston Kemp also notes that the estimated value of benefits increases from around 2028, when it is assumed that there starts to be a material reduction in the level of large synchronous generators connected to the power system. Should there be any delay to this forecast reduction in synchronous inertia the estimated benefits will be similarly delayed.

ENA considers the presently estimated benefits from operational procurement of additional inertia are not necessarily substantially greater than the estimated costs of implementation. This leaves little margin should implementation costs increase or the estimated benefits from additional inertia decrease or be delayed. This contrasts with other market reform rule changes where the AEMC has pointed to quite substantial estimated benefits that could clearly outweigh implementation costs[1].

Moreover, the procurement of the minimum inertia demand by Inertia Service Providers (primarily TNSPs) under the ISF rule change is currently underway. Under the system strength framework, TNSPs are procuring system strength, where synchronous condensers are procured, these are likely to include a higher inertia fly-wheel. ENA consider that once these initial procurement processes are completed and their operational arrangements bedded down the expected demand for additional inertia can be more clearly understood. At this time the AEMC will be able to form a better view of the economic case for introducing a new operational procurement mechanism.

ENA also notes that AEMO is not due to finalise its new Security Enablement Procedures until after the Draft Determination for this Rule change is due. We consider the details of this procedure will need to inform the additional analysis that will be necessary to better understand the benefits and costs of procuring additional inertia.

6. Implementation considerations

As noted above ENA considers the AEMC should not rush to implement a new operational procurement mechanism for additional inertia. Nevertheless, if the AEMC does decide to progress operational procurement at this time ENA considers the following matters are important to any implementation:

[1] For example, Unlocking CER benefits through flexible trading.

- AEMC should assess how a staged implementation of any operational procurement mechanism could be delivered. One such option could be the co-optimised dispatch of additional inertia using pre-committed, fixed offer prices. This could allow some of the benefits of operational procurement to be realised without committing to significant development of participants' bidding systems.

- ENA has reservations about creating different eligibility criteria between inertia provided through long-term contracts and inertia provided through operational procurement as canvassed in the Directions Paper[2]. Differential eligibility could create inefficiencies in one or other of the two markets. If not carefully thought through this could lead to wealth transfers from electricity consumers to inertia providers and undermine the benefits of operational procurement.

In any reform of the arrangements for the efficient provision of inertia ENA urges the AEMC to ensure that the arrangements for cost recovery align with the risk profile of the party responsible for procurement. Arrangements where AEMO makes operational decisions in relation to power system security resources procured by TNSPs that result in highly variable and volatile cash-flows for TNSPs are incompatible with TNSPs regulated revenue arrangements. TNSP cost recovery through regulated annual transmission prices is well suited to large fixed-cost, long-term contracting arrangements with service providers. Where the costs of service provision are highly changeable based on market and power system conditions and interact with spot market dispatch and pricing outcomes ENA considers these are better suited to recovery through AEMO's weekly settlement processes.

[2] Directions Paper, Table 8.1, p51.