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AEMC

By website

RE: Efficient Provision of Inertia – Consultation Paper[1]

Iberdrola Australia welcomes the opportunity to make a submission. Iberdrola Australia delivers reliable energy to customers through a portfolio of wind capacity across New South Wales, South Australia, Victoria, and Western Australia, including both vertical integrated assets and PPAs. Iberdrola Australia also owns and operates a portfolio of firming capacity, including open cycle gas turbines, dual fuel peaking capacity, and battery storage. Our development pipeline has projects at differing stages of development covering wind, solar and batteries. This broad portfolio of assets has allowed us to retail electricity to over 400 metered sites to some of Australia's most iconic large energy users.

Iberdrola Australia is part of the global Iberdrola group. With more than 120 years of history, Iberdrola is a global energy leader, the world's number-one producer of wind power, an operator of large-scale transmission and distribution assets in three continents making it one of the world's biggest electricity utilities by market capitalisation. The group supplies energy to almost 100 million people in dozens of countries, has a workforce of more than 37,000 employees and operates energy assets worth more than €123 billion.

1. Overview

Iberdrola Australia supports a mechanism that will ensure sufficient inertia is available to operate a least-cost grid. Currently, only a "minimum" level of inertia can be procured to manage system security issues. However, it is credible that operational shortfalls of inertia will occur in sub-regions as well as the connected mainland NEM this decade as coal units close. This could lead to the inability to

[1] https://www.aemc.gov.au/sites/default/files/2023-03/ERC0339%20-%20Consultation%20Paper.pdf

operate the grid efficiently or, potentially, even at all if coal closures are not anticipated.

The AEMC's primary concern should be the development of a mechanism that i) increases the speed and ii) reduces the complexity of decarbonising and electrifying the NEM, and does not increase NEM emissions. These evaluation criteria are supported by the upcoming enhancements to the NEO to consider emissions reduction. In evaluating any prospective mechanism, the AEMC should consider:

- The complexity of the change – whether it will make investment easier or more challenging, in both new energy sources (e.g., VRE) as well as the provision of inertia
- Whether a prospective rule is likely to extend the life (and therefore emissions) of coal generators, which will have a material long-term cost to consumers
- Whether the resulting procurement mechanism will provide clear and transparent prices that reduces uncertainty for parties seeking long-term contracts.
- How the mechanism will facilitate the cooptimisation of both investment and dispatch of inertia provision.

By considering these things, it is highly likely that costs to consumers in relation to decarbonisation will be minimised.

Establishing an inertia service will support unbundling of system services, and allow for greater transparency of any "unbundled" requirements (for example, synchronous unit directions in South Australia or any services procured under the OSM framework). Unbundling system services should be a priority for AEMO, reducing the incidence of opaque costs to consumers and supporting the rapid decarbonisation of the NEM.

The mechanism will need to create long-term signals for investment and enablement of inertia, which are currently lacking in the market. We note there is significant work required from AEMO to:

- Quantify the potential quantity of inertia and FFR required to operate the future system, providing a long-term signal for investors. We expect this projection would be included in the ESOO (near-term) and ISP (long-term) publications
- Publish the necessary requirements from grid forming inverters to deliver the inertia service. A consistent, transparent definition will be required for a spot market to be able to provide effective investment signals.
    - This includes how and under what conditions (and over what range) the inertia constant of an IBR can be altered in real-time.

The AEMC should work with AEMO (and/or other technical consultants) to ensure these questions are addressed before the Draft Determination is released.

Our initial position is that a spot market will be required for the efficient dispatch and cooptimisation of inertia. However, there may also be a role for longer-term contracts (particularly initially) to ensure investment occurs in a timely and proactive manner, and is coordinated with any system strength investment.

2. Future inertia provision

A key question for the design of the service is what resources will be providing inertia in the future. Given the relatively low inertia constants of typical gas turbines, it seems likely that inertia will be provided by:

- Batteries providing synthetic inertia, with inertia constants ranging from 0.1 to 50+ MWs/MVA[2]. The Hornsdale Power Reserve has tested an inertia constant of 11.02 MWs/MVA[3]
- Synchronous condensors (syncons), with flywheels to provide additional inertia (similar to those in South Australia), including existing synchronous units transitioned to syncons (for example, consistent with Queensland's Energy and Jobs Plan)
- Hydro generators operating in synchronous condenser mode

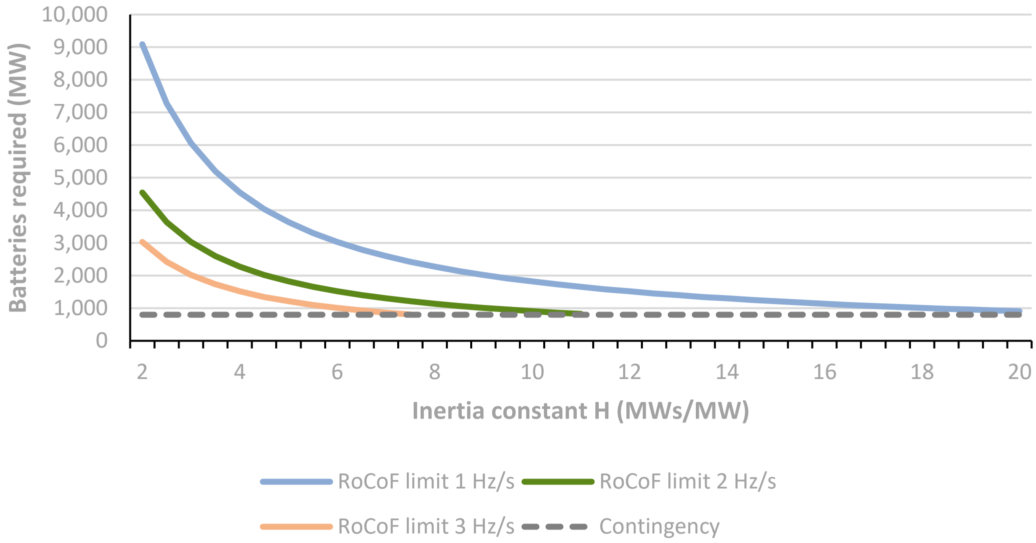
It would be helpful to understand what the future "size of the pie" would look like, and what a least-cost mix would involve. As an indicative example (noting these are only "order of magnitude" figures, rather than what might actually be required) if a grid were to be designed to withstand a 800 MW contingency with a RoCoF of 1.0 Hz/s, approximately 20,000 MWs of inertia would be required based on the swing equation

$$K_{req} = \frac{1}{2} f_0 \frac{\Delta P}{\mathrm{RoCoF_{limit}}}$$

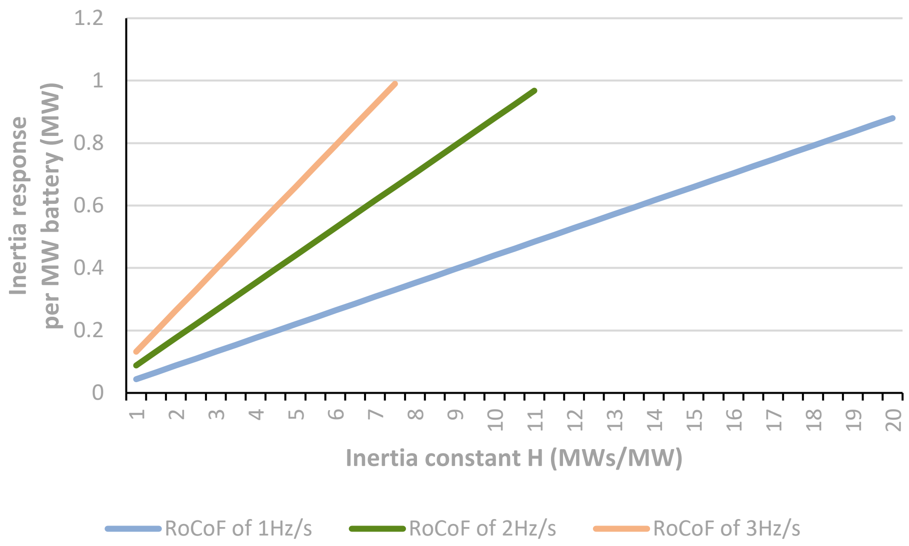
The quantity of batteries required to supply this inertia would depend on the inertia constant, and is given by $S_{\mathrm{total}} = \frac{1}{2} f_0 \frac{\Delta P}{H_{batt}} \times \frac{1}{\mathrm{RoCoF}_{limit}}$

[2] p10, https://www.aemc.gov.au/sites/default/files/2021-06/Tesla.pdf

[3] https://arena.gov.au/assets/2022/03/hornsdale-power-reserve-virtual-machine-mode-testing-summary-report.pdf



The response from an individual battery is again based on the swing equation, and is given by $\frac{\text{MW response}}{\text{MW nameplate}} = \frac{2}{f_0} \times RoCoF_{limit} \times H_{batt}$, adjusted for MVA. For example, at 11 MWs/MVA, around 2000 MW of capacity would be required, and each battery would require approximately 50% of its nameplate capacity as headroom, based on the response to a RoCoF of 1.0.



However, most inverters provide some level of overload capability. Assuming that inertia response would not be required for more than a few seconds, it may be that additional response could be made available above the nameplate capacity. This could allow for additional inertia to be procured from a resource beyond its nameplate rating and/or would provide additional buffer to provide inertial response to (for example) non-credible contingency events.

We also note that it is highly likely that contingency FCAS (cFCAS) and inertia would be provided simultaneously by batteries. That is, both grid forming (automatic response proportional to RoCoF) and grid following (measured response proportional to the change in frequency) control systems would operate in parallel. The inertial response would “hand over” to the cFCAS response once the change in frequency was measured and deadbands exceeded.

This means:

- Batteries that reserve capacity for one service (cFCAS) will be able to simultaneously provide inertia.
- However, this may not be a one-to-one trade off. For example, with a sufficiently fast droop, a battery may provide its entire nameplate to the FFR service. However, depending on the H constant and total quantity of inertia required, the headroom may need to be distributed around more nameplate capacity (to ensure the required response is delivered, as described in the analysis above)
    - It will therefore be important to establish market signals that ensure that headroom is optimally distributed across resources and can be used to deliver both inertial and contingency FCAS
- Similarly, FFR will compensate partially for the need for inertia, and therefore there will be a cooptimisation on the demand side as well. This needs to be articulated quickly by AEMO.
- Batteries are likely to be able to offer varying quantities of inertia by varying their inertia constant, potentially in real time. This provides a further source of optimisation. For example:
    - Rather than enabling 1,800 MW of batteries with H=10 but with ~40% headroom it might be more efficient to enable 3,600 MW of batteries (H=5) with ~20% headroom,
    - This could allow better optimisation across portfolios (for example, if one participant requires the battery to operate in the energy market to meet a hedge position).
- Similarly, it would be appropriate to consider whether the droop coefficient of an IBR (which determines its cFCAS capability, including FFR) should also be dynamic (e.g., allowed to vary between 0.7% and 1.7%). This would maximise the efficient participation of resources across energy, inertia and cFCAS markets.

A similar cooptimisation likely exists in the procurement of synchronous condensors. For example, AEMO estimates[4] that 40 syncons (125 MVA nameplate, 575 MVA fault current contribution) would be sufficient to manage low-demand system strength (SS) needs (in the absence of SS from batteries, etc.) Based on the SA syncons , this would deliver 44,000 MWs of inertia.

ElectraNet reported an additional cost of 3% of capex to deliver the additional inertia. If these syncons were part of the least cost solution to meeting the system strength

[4] https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/2022-inertia-report.pdf?la=en

requirements, it *may* be efficient to procure some additional inertia in conjunction with system strength. However, there may be significant inertia available from IBR at low-cost. This requires further investigation.

Any market design should not preclude this co-optimisation. However, it is important that the TNSPs do not have a monopoly on provision and should seek to contract rather than own-and-operate the appropriate resources.

3. Procurement options

General comments

- The AEMC should consider whether the fundamental service to be procured is an "inertia" service or a "RoCoF" service – that is, whether the fundamental need in the system is some form of inertia or whether the fundamental need is to limit RoCoF. It currently seems likely that these two definitions are interchangeable, but this should be clarified.
- Related, IBR are highly flexible and configurable. The AEMC should not preclude the existence of "better than inertia" services in the future. For example, it could be conceivable that after a low frequency event, a battery's inertia constant in the raise direction (only) is reduced such that it continues to resist further falls in frequency but is "light" for the purposes of restoring frequency (and vice vera for an over-frequency event). This example is not intended to be a proposed feature of a future market, but rather highlighting the need for the AEMC to make a Rule that will provide maximum flexibility (and co-optimisation opportunities) as technology and understanding of engineering control systems continues to improve.
- Cost recovery needs to be transparent and forecastable. We note that significant and unforecastable costs are regularly being placed on participants, for example RERT and the proposed Operational Security Mechanism.
- To the extent that TNSPs contract eligible resources to deliver system strength, inertia procurement should be considered at the same time, but TNSPs should be seeking to contract not build the relevant resources to avoid conflicts.
- It seems likely that a spot market will be required (in some form) to allow for the efficient cooptimisation and dispatch of inertia in real-time. However, there may also be a role for structured procurement (longer-term contracts), particularly initially and particularly if there is uncertainty over the quantity of future resource required.
- We recommend that the final Rule includes obligations on AEMO to publish inertia requirements in the ESOO to ensure that efficient investment signals are available to participants.

Spot markets

We agree that further investigation and design of a spot market is warranted. Unlike system strength, inertia is only weakly locationally specific (similar to other contingency and regulation FCAS requirements) unless there is a risk of islanding of an electrical sub-network. In terms of the AEC's proposal, we note:

- Spot markets provide the natural mechanism for cooptimising inertia with FFR, contingency size, and (if applicable) RoCoF withstand capability.
- Reusing the first bid band as an inertia bid requires further consideration.
  - We see this could be an effective approach for synchronous generators whose inertia is fixed, and it ensures that generators cannot game the inertia market by "financially withholding" inertia that has to be physically delivered to the grid.
  - Alternatively, any synchronous unit that is online for energy provision could simply be considered a price-taker in the inertia spot market as their inertia bid would typically be negative in any case.
- It will likely be efficient for the inertia provision from IBR to vary according to system needs. IBR may therefore offer multiple bids reflecting multiple H constants, and a single price band may not be sufficient
- In general, the quantity of inertia available from IBR may vary according to other conditions (for example, wind speed).
- We note that RoCoF standard to be implemented in the Frequency Operating Standard (FOS) and associated requirements on existing and new entrant generators should be reviewed as quickly as possible. This may involve considering:
  - The required capabilities of new generators
  - Cost recovery of inertia and FFR services proportional to RoCoF withstand capability (i.e., a form of causer pays for inertia)
  - Whether RoCoF withstand capability is appropriately considered in NEMDE. i.e., whether the total cost of dispatch could be lower if a unit that requires a tight RoCoF is not dispatched in favour of a more expensive unit in the bid stack, but which leads to a lower cost of inertia procurement. As noted in our previous submissions, a single fixed RoCoF requirement in the FOS does not allow for this sort of efficient real-time optimisation.

Structured procurement

TNSPs currently are required to contract or procure sufficient system strength resources to facilitate an efficient future grid. Expanding this framework should be given further consideration, noting that the proposed system strength framework has been received positively by stakeholders. Medium to long-term contracts for services will support investment, and may make marginal storage projects more bankable. We emphasise that TNSPs should seek to contract services rather than own and operate assets, which (regardless of inertia procurement method) will allow value stacking to be realised outside of their regulated asset base.

Any contracts for inertia should include an emissions intensity limit (likely zero), to support investment in future resources that can speed up the decarbonisation of the NEM.

It may also be that a hybrid model is required, such that inertia is contracted but then dispatched in a spot market. A real-time spot market would be appropriate, with resources managing their own commitment. We do not support using the proposed OSM framework for the dispatch or procurement of inertia.

Appropriate guidelines for contracting would be required to ensure that bids into the spot market are efficient.

We do not support AEMO procuring inertia contracts over short- or long-timeframes. Except for services such as system restart, AEMO should focus on the operation of the grid and the spot market. There would be no synergies available through AEMO procurement (whereas spot markets or TNSPs may be able to efficient cooptimise procuring inertia with the procurement and operation other generation or network assets).

Shadow price market

We consider that the shadow price approach may have merit; it provides a simpler mechanism for valuing the “discretionary” inertia. Under this model, the marginal value of an additional MWs of inertia would be determined based on constraint equations, and paid to all providers. We expect that this would be zero for the majority of periods in the near-term, given that no immediate inertia shortfall is expected.

Further clarity on exactly what inertia constraints are likely to operate and how the “minimum” inertia requirements could be expressed and priced may be required.

We also caution against windfall payments to thermal generators that might risk increasing NEM emissions. It may not be necessary or efficient to make inertia payments to units whose commitment or closure decisions are unlikely to be contingent on inertia payments (that is, they will be driven by asset lifetimes and emissions limits).

We note however that shadow pricing would rely on participants making inertia available due to expected price signals, rather than receiving an explicit dispatch instruction for provision (as occurs for energy and FCAS). This concern is similar to the material risk of the Mandatory Primary Frequency Response service, where a quantity of headroom will be required but there is no explicit mechanism for procuring it from the market. Iberdrola Australia continues to support direct procurement of services which are needed, including headroom for Primary Frequency Response.

Ahead markets for inertia

Iberdrola Australia does not support ahead market for the NEM, nor the use of the proposed OSM service for procuring inertia. These approaches provide neither the efficiency of a real-time market nor the investment certainty of a longer-term structured procurement mechanism. They also goes against the continued work the AEMC has undertaken to move the market to closer to real-time (e.g., 5 Minute Settlement).

We see there is a material risk of market gaming by large thermal generators, leading to increased costs and emissions, coupled with the inefficiencies of a centrally dispatched market. We encourage AEMO to continue to focus on the technical work required for unbundling of services.

Conclusion

We look forward to continuing to engage with the AEMC on this issue, and would be happy to further discuss the capabilities of inverter based resources. Please do not hesitate to contact me if you have any questions on joel.gilmore@iberdrola.com.au or 0411267044.

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