perthenergy

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Economic Regulation Authority
PO Box 8469
Perth BC WA 6849

Lodged online at http://www.erawa.com.au/consultation

Response to Issues Paper: Margin Values and Cost_LR Ancillary Services parameters for 2020/21

Perth Energy submits this paper in response to the Economic Regulation Authority's (ERA) issues paper on the Australian Energy Market Operator's (AEMO) proposed ancillary service parameters and values for spinning reserve, load rejection reserve and system restart service for 2020/21.

Perth Energy notes that the ERA appears to have commenced this review with a view that Ancillary Services costs are "too high" and there should be an "effort to reduce costs further". In the context of increasing network and reform costs, we consider any genuine decrease in the costs of wholesale electricity to be positive for customers. However, it is clear that AEMO is finding it increasingly difficult to maintain system stability with the current uptake of intermittent generation. The costs associated with any resulting customer supply interruptions due to limiting the Ancillary Services requirement, or improperly remunerating Synergy is likely to quickly overwhelm any short-term savings.

The various modelling assumptions appear reasonable. However, they raise two issues that we recommend are examined further by the ERA:

1. **The inconsistency of the ERA's estimated average price and Synergy's Standard Product prices** - Synergy's Standard Products offered under the Electricity Generation and Retail Corporation transfer pricing scheme are currently priced well above the ERA's estimated average price (even using a $7.00/GJ gas price). Perth Energy considers the ERA should investigate the discrepancy, and determine an appropriate price that should be applied to both market power mitigation mechanisms - the administered price as the last-resort provider of Ancillary Services, and the transfer pricing scheme.
2. **The inclusion of the North Country network constraint in the Spinning Reserve Ancillary Services Requirement –** We appreciate this has been a topic of conversation at multiple Market Advisory Committee meetings and is yet to be resolved. We note that AEMO has included network contingencies (similar to the North Country network constraint) in prior years' reports submitted to the ERA under clause 3.11.6 of the WEM Rules. However, we note that the inclusion of a network-driven contingency in setting the requirement is inconsistent with clause 3.10.2(a) of the Wholesale Electricity Market (WEM) Rules which refers to contingencies of "the generation unit…

with the highest total output". The increase in requirement driven by this new network contingency cannot be included in the requirement until the WEM Rules are amended to allow it.

Our responses to the ERA's specific questions are provided at Attachment A.

Should you have any questions please contact me on (08) 9420 0347 or at e.aitken@perthenergy.com.au.

Regards,

[redacted]

Elizabeth Aitken

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Attachment A: Response to the ERA's specific questions

Perth Energy welcomes the opportunity to provide comment in relation to AEMO's proposed ancillary service parameters and values more broadly, and in response to the ERA's specific questions:

1. Given the reductions in spinning reserve and load rejection reserve costs, do market participants consider the values are still too high?
2. How should the effort to reduce costs further be considered in the remaining two years? Our comments on each are provided in the following sections.
3. Do market participants consider a forecast gas price of $3.50 per GJ (delivered) to be a reasonable assumption? If not, why not? What would be a reasonable basis to determine the forecast price for gas?
4. Do stakeholders consider the modelling approach to identify the load rejection reserve cost is reasonable? If not, please explain why?
5. In what way, if any, are wind and solar farms able to contribute to load rejection reserve? How should their contribution be considered in determining the load rejection reserve value?
6. What barriers do you see to providing system restart services and how could AEMO structure its procurement process to deliver more competitive/lower cost outcomes?
7. Could the system restart service be provided from other areas of the network to encourage participation from more service providers or other existing facilities, for example in North Country, east Country, Eastern goldfields or other areas?

Our comments on each are provided in the following sections.

1. Given the reductions in spinning reserve and load rejection reserve costs, do market participants consider the values are still too high?

2. How should the effort to reduce costs further be considered in the remaining two years?

Perth Energy notes that the cost for these services has been reduced over the past two years and appreciates that this is a real saving that can be passed through to customers. We see this as positive in that it counters, albeit in a small way, the additional costs being faced by customers for network costs and the costs of the reforms under the Energy Transformation Strategy.

While further cost reductions would benefit end-use customers, we do not see this as being a high priority for two reasons. Firstly, nothing should be allowed to take resources away from ensuring that the proposed security constrained dispatch system can be implemented within the proposed timeframe, or earlier if at all possible. The current dispatch system is clearly at the end of its affective life and it is critical that all market participants concentrate on development, installation, testing and implementing the proposed replacement engine. Perth Energy would not want to see the market's limited resources diverted from this work for the sake of what would be relatively minor savings.

Secondly, we consider that any activities to reduce the amount of spinning reserve or load rejection reserve actually provided could be counter-productive. AEMO is clearly struggling to cope with the increased penetration of intermittent generation which is accentuated by long gate closure and the inflexible Synergy generation fleet. The costs associated with any increase in customer supply interruptions due to limiting Ancillary Services is likely to quickly overwhelm any savings.

3. Do market participants consider a forecast gas price of $3.50 per GJ (delivered) to be a reasonable assumption? If not, why not? What would be a reasonable basis to determine the forecast price for gas?

Perth Energy considers that the figure of $3.50/GJ is a reasonable assumption given the DMIRS data and the historical spot price information referred to. We also note that the sensitivity analysis, using a gas price of $7.00, showed a relatively small change in the total costs of Ancillary Services.

As an aside, it is of concern that Synergy's Standard Products required to be provided under the transfer pricing scheme are priced well above the ERA's estimated average price (even based on a $7.00/GJ gas price). It would be appropriate for the ERA to examine this and use the same price for both market power mitigation schemes.

4. Do stakeholders consider the modelling approach to identify the load rejection reserve cost is reasonable? If not, please explain why?

5. In what way, if any, are wind and solar farms able to contribute to load rejection reserve? How should their contribution be considered in determining the load rejection reserve value?

The modelling approach used by the ERA appears to better reflect the actual level of reserve held by AEMO and so is considered to be reasonable.

As noted in the issues paper, wind and solar farms can reduce their output quickly without adverse technical ramifications and it would be appropriate to consider making more use of them for the period until the new dispatch system is implemented. The paper suggests that this reserve would rarely be called upon. Also, it is likely that AEMO would be able to reconfigure the dispatch order relatively quickly so the imposition placed on wind or solar farms should not be high.

6. What barriers do you see to providing system restart services and how could AEMO structure its procurement process to deliver more competitive/lower cost outcomes?

7. Could the system restart service be provided from other areas of the network to encourage participation from more service providers or other existing facilities, for example in North Country, east Country, Eastern goldfields or other areas?

Answering the second question first, there are major technical issues in providing System Restart Services from other areas of the system because of the generation capacity required to charge up transmission lines and deliver energy. Detailed assessment undertaken a couple of years ago showed that Perth Energy's Kwinana Swift facility, even with over 100 MW of capacity available, would struggle to start any generators in the North Metropolitan Area and would not be able to start a generator in the South Country

Region. A very large machine, or group of machines would be required to charge up inter-area transmission lines and this large machine would, in turn, require a substantial black start generator to get it started. The cost of providing black start for a large generator is high as can be seen from the costs associated with the South Country System Restart Services contract.

Existing System Restart Services generators have immense market power because of their location. For this reason a competitive process is unlikely to lead to any cost reductions. It should also be noted that since the contracts moved from Western Power to AEMO the costs which Western Power charge for testing, which it had previously absorbed, are now billed to black start generators.

For these reasons the cost of providing System Restart Services has increased and there is unlikely to be any opportunity to achieve significant contract price reductions.