synergy

Our Ref: DM#21409556
Enquiries: Angelina Cox
Telephone: 08 6282 7459

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Martin Maticka
Group Manager, WA Markets
Australian Electricity Market Operator
Central Park
152 St Georges Terrace
Perth WA 6000

via email: wa.operations@aemo.com.au

Dear Martin

ANCILLARY SERVICES PARAMETERS – 2019 DRAFT METHODOLOGY AND ASSUMPTIONS REPORT

Synergy appreciates the opportunity to provide feedback on the ***2019 Draft Methodology and Assumptions Report (the Report)*** published by AEMO on 18 September 2019. The Report details proposed methods and assumptions for calculating the compensation Synergy requires to recover its costs as the default provider for Load Rejection and Spinning Reserve Services.

Synergy recognises the stakeholder feedback from the *2018 Methodology and Assumptions Report* that AEMO has incorporated in its draft 2019 report. Synergy also recognises the proactive consultation AEMO has undertaken with the industry prior to the publication of this report.

Synergy would like to raise the following issues and proposed resolutions in relation to the 2019 Draft Methodology and Assumptions Report for AEMO's further consideration.

1. Section 3.4 of the Report: Calculation of the Load Rejection Reserve Requirement

Synergy notes that the provision of Load Rejection Reserve (LRR) often requires units to be committed and run out of merit. Synergy considers that the calculation of compensation based on AEMO's proposal to model a dynamic Load Rejection Reserve (LRR) requirement in close to real time risks understating the actual costs Synergy incurs in providing LRR. This is

because Synergy's offer pricing[1] and unit commitment decisions must allow for a maximum likely LRR which may be more that what is utilised in real-time.

Any downward revision in the LRR requirement occurring between Synergy's gate closure and the relevant trading interval arising from a dynamic LRR requirement would result in Synergy's costs being remunerated based on the near-real-time requirement, rather than the quantities reserved (often below cost) in Synergy's offers. Under current market arrangements, Synergy does not have an opportunity to revise its offer near real time to reduce the volume offered at the floor (and, clearly, below cost).

Therefore, Synergy recommends that even if the application of a dynamic LRR requirement is adopted by AEMO, the calculation of compensation should be included that allows for the full recovery of the relevant costs based on quantities required to be reserved at the point of Synergy's gate closure and not on any downward revision of the LRR occurring after.

2. Section 4 of the Report: Modelling of unit commitment and reliance on historical offer information

Start costs, particularly for coal generating units, are significant and can exceed $100,000 per start. When deciding which facilities to commit, generation businesses take a forward view of load forecasts over several days and price to recover start costs accordingly. Hence market participants' offers are intrinsically linked with expectations of future load, and especially with intra-day load shape. Synergy notes that the level and shape of load available for thermal generation will fundamentally shift during 2020/21 due to the entry of several large-scale renewable facilities and incremental installation of rooftop PV.

Synergy considers that unit commitment decisions and the costs associated with them are key factors in determining the cost of SRAS and LRR. This relationship is more pronounced in a small, isolated system such as the SWIS, where facilities' minimum stable operating levels are material relative to the system load available for scheduled generation. To reflect this, Synergy considers the modelling method should demonstrate unit commitment with a forward view of 2-4 days. Synergy notes that some previous reviews incorporated full integer unit commitment modelling, co-optimised for provision of all ancillary services.

In Synergy's view, the assumption that historical offer information can be used to derive likely future offers (in place of unit commitment modelling) is problematic. Generation costs are more complex than can be represented in a series of monotonically increasing price-quantity

[1] which requires quantities to be bid at the floor price up to 10 hours in advance of the relevant trading interval.

pairs, and the process by which market participants prepare their offers necessarily results in a loss of information: costs cannot be re-created from offers.

It is unreasonable to assume that future bidding profiles will reflect past profiles and that the net load profiles will remain constant, given the uptake of distributed solar PV and planned new large-scale non-scheduled generation.

3. Section 4 of the Report: Information required to assess accuracy of the model assumptions and method

Synergy considers that the following information is necessary for stakeholders to assess and provide informed feedback on the accuracy of the assumptions and methods used to forecast Synergy's costs of providing spinning and load rejection reserve:

- Dispatch metrics by facility, such as capacity factors, operating hours and start events.
- Annual plant availability statistics broken down into planned and forced outages.
- Provision of ancillary services by facility.
- A load-duration curve for system load net of non-scheduled generation.
- A forecast balancing price duration curve.

Synergy requests that AEMO provide this information to inform stakeholders' assessments and feedback.

4. Appendix A (A.6) of the Report: Greenough River Stage 2 start date

Synergy notes that it currently expects Greenough River Stage 2 (additional 30MW) to enter commercial operation early Q2 of 2020, not 1 October 2020 as used in the model.

5. Appendix B of the Report: LFAS Assumptions

Synergy notes AEMO forecasts that the off-peak LFAS requirement (7.30 PM to 05:30 AM) will increase to a minimum of 70 MW over the forecast period. Synergy notes that this is very similar to the historic LFAS requirement for this period (72 MW) which applied from market start up to 27 August 2019.

With respect to offer quantities and dispatch priorities in the LFAS up market and LFAS down market for non-Synergy participants (specifically for 21:00 – 05:00 in Table 10 and Table 11, Appendix B), Synergy considers that AEMO's proposal could be improved by referencing non-Synergy participant offer behaviour over a comparable period, being from Alinta's entry into the LFAS market in February 2019 up to when the market LFAS requirement changed from 72 MW on 28 August 2019. Synergy notes that the available market LFAS quantities for this period, and the incentives for non-Synergy participation, align with AEMO's proposed minimum market off-peak time quantity for 2020/21.

Further, Synergy notes that a step change in non-Synergy LFAS participants offer behaviour occurred on 28 August 2019 and for this reason does not believe that the period post 28 August 2019, where the market requirement was 50 MW, is representative of the likely non-Synergy participant participation where the market requirement is 70 MW.

6. Not addressed in the Report: Real-time consumption of LFAS increases market requirement for SRAS or LRR

Synergy notes that, in line with increasing rooftop solar and new large-scale renewables, AEMO recommends an increase in the peak LFAS quantity to 116 MW (up 36%) and an increase in the off-peak LFAS quantity to 70 MW (up 40%). Synergy acknowledges that, with the changing circumstance of the SWIS, actual utilisation of LFAS will increase.

Synergy also notes that real-time consumption of either LFAS up or LFAS down has a consequential impact on the availability of spinning reserve (SRAS) or load rejection (LRR) respectively. As LFAS up is consumed in real-time, the contribution towards SRAS of units which were providing both LFAS up and SRAS diminishes. Similarly, as LFAS down is consumed in real-time, the contribution towards LRAS of units which were providing both LFAS down and LRR diminishes.

Synergy is of a view that even if the measurement of the actual utilisation of LFAS up and LFAS down is difficult, reasonable estimates of this are required to adequately estimate both the quantity required, and cost thereof, SRAS and LRAS. Synergy requests that real-time consumption of LFAS up or LFAS down is considered when determining costs and compensation for SRAS and LRR.

Once again, thank you for the opportunity to provide feedback. Synergy would be pleased to elaborate on the points raised above, if required.

Yours sincerely,

ANGELINA COX
A/MANAGER, ENERGY TRADING