Government of South Australia
Department of the Premier and Cabinet

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Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Frequency Control Frameworks Review – Issues Paper (EPR0059)

Dear Mr Pierce

The Energy and Technical Regulation Division of the Department of the Premier and Cabinet, South Australia (Division) welcomes the opportunity to comment on the Issues Paper for the *Frequency Control Frameworks Review* published by the Australian Energy Market Commission (AEMC or Commission).

South Australia is experiencing a rapid change in the generation mix present in the state, which is presenting new challenges relating to the management of power system security, in particular the management of system frequency. As such, the development of robust frameworks to address the changed market conditions represents a priority for the South Australian Government. The development of national frameworks has not kept pace with the changes taking place in South Australia and, as such, local initiatives – such as the introduction of more robust technical requirements in generation licences – have been necessary to help maintain system security.

The Division considers that the Issues Paper correctly identifies and effectively articulates the frequency management challenges emerging in the National Electricity Market (NEM). The remainder of this submission provides comments relating to a number of the issues identified. The submission also comments on the use of the review as a means of progressing the development of an inertia service, following the AEMC's draft determination for the *Inertia Ancillary Service Market* rule change.

Primary frequency control

The Division finds the recent degradation in frequency performance highlighted in DigSILENT's work for the Australian Energy Market Operator (AEMO), and presented in the Issues Paper, to be deeply concerning. It is difficult to imagine that, when the decision was taken to remove the requirements for mandatory governor response in November 2003, the full consequences of this step were appreciated.

Figure 5.1 in the Issues Paper presents a stark illustration of the flattening and spreading of the frequency distribution since 2001, and foreshadows a further deterioration. While, as shown by Figure 3.6, the requirements of the Frequency Operating Standard are still being met in general, the Division suggests that these requirements would have been set with an implicit assumption being made around the frequency distribution profile. Such an assumption clearly no longer holds.

While the Division agrees with all the risks listed in the Issues Paper associated with deteriorating frequency control performance and the removal of governor response within the normal frequency operating band, it is the impact on contingency events that the Division considers to be of most concern. The further away the frequency is from 50 Hz during normal operation, the greater the risks that will then arise from a given contingency event. The more timely activation of primary frequency control through restoration of the mandatory governor response requirements would lead to a lower Rate of Change of Frequency (RoCoF) and reduced magnitude of frequency deviation following a contingency event than would otherwise be the case.

The Division agrees with the statements in the Issues Paper that: "The removal of the requirement for the requirement for mandatory response was not an inherent result of introducing FCAS [Frequency Control Ancillary Services] markets – the spot markets for enablement simply replaced the previous contracting approach [for headroom]. It would have been possible to continue to impose the mandatory response obligation'.[1]

As such, the Division considers that table 5.1 and the accompanying discussion could have more clearly drawn out the differences between the mandatory provision of energy (i.e. the actual response) and capacity (maintaining headroom) when discussing experience in international markets. The Division notes that mandatory primary frequency response is a default requirement in all US markets.[2] Further, data provided by the Electric Reliability Council of Texas (ERCOT) shows that the total response of governors drops with tighter deadbands.[3] This implies that the reintroduction of mandatory governor requirements in the NEM would likely reduce overall costs.

The Division therefore considers that the Commission should focus its work on how to achieve such an outcome. The Division notes the Commission's view that the reintroduction of mandatory requirements may impact on the accrued rights of generators with pre-existing connection agreements and, as such, may be inconsistent with the provisions of clause 33(1) of Schedule 2 to the National Electricity Law.

Given that the efficacy of mandatory governor response as a solution would be dependent on its application to all generators in the market, the Division suggests that the Commission consider this issue further. The interpretation of clause 33(1) outlined in the paper would imply that the Commission would not have had the power to remove the mandatory governor response requirements had the existing governance arrangements been in place in 2003. In any event, this restriction could ultimately be overcome through legislation, although the Division would be keen for the Commission to identify any potential alternative approaches.

The Division further suggests that the Commission give consideration as to how equivalent requirements could be defined for non-synchronous generating units, which now make up a significant part of the generation fleet in South Australia. The Division

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[1] AEMC, *Frequency Control Frameworks Review*, Issues Paper, 7 November 2017, p.27.

[2] Although there are numerous exemptions, for instance for nuclear generating units.

[3] Nicholas W. Miller, *Frequency Control: A US Centric View*, CEC workshop on FCAS, 20 April 2017, slide 9.

notes that, in the US, the Federal Energy Regulatory Commission (FERC) is currently considering this issue, and has recently consulted on how to apply mandatory primary frequency response requirements to electric storage resources.[4]

Fast Frequency Response

The Division is supportive of the Commission's work to incorporate new, faster responding technologies into contingency and regulation FCAS markets. The Division notes AEMO's analysis that RoCoF levels relating to credible contingency events for the NEM mainland could be in the range of 0.2-0.3 Hz/s for more than 40% of the time by 2021-22, and its conclusion that: "At this level of RoCoF, there is less than two seconds for primary frequency control actions to arrest the frequency decline before frequency leaves the containment band".[5]

Noting that the Commission recently considered it necessary to delay the implementation of a rule change to allow the benefits of new faster responding technologies to be realised in the energy market until mid-2021,[6] the Division suggests that the development of new contingency FCAS markets for fast frequency response (FFR) must therefore be progressed as a priority. By early 2018, two grid-scale batteries will be operational in South Australia, and the inability of the market to access the enhanced services that they could provide represents a major missed opportunity.

The Division recognises that the different technical characteristics of different FFR technologies make it difficult to design a homogenous service specification. However, a one or two second response service that need only be sustained until the existing six second service has responded would appear most consistent with current market arrangements. It would also be well suited to wind inertia-based FFR, which requires no headroom and can be sustained for ~10 seconds.[7]

The Division further suggests that the Commission work with AEMO to unlock the benefits that can be provided by FFR units in providing secondary response through regulation FCAS. Currently, steam units providing regulation FCAS can have a response time of minutes, which would not appear consistent with good frequency management in an increasingly dynamic system. In contrast, FFR would allow for a much more rapid and precise response. AEMO notes that the "pay for performance" approach adopted in PJM has been highly successful in encouraging faster response,[8] and the Division encourages the Commission to consider the application of this concept to regulation FCAS further.

FCAS Cost Recovery

The Division notes that AEMO has been undertaking a review of the causer pays methodology for regulation FCAS, and agrees with the Commission there does not appear to be a clear linkage between behaviour and cost recovery in these

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[4] FERC, *Essential Reliability Services and the Evolving Bulk-Power System – Primary Frequency Response*, Notice of Request for Supplemental Comments, 24 August 2017.

[5] AEMO, *Fast Frequency Response in the NEM*, Future Power System Security Program, Working Paper, August 2017, p. 14.

[6] AEMC, *Five Minute Settlement*, Final Determination, 28 November 2017.

[7] AEMO, *Fast Frequency Response in the NEM*, Future Power System Security Program, Working Paper, August 2017, p. 18.

[8] Ibid, p. 31.

arrangements. The use of backward-looking factors mutes the price signal in any given dispatch interval and may encourage unintended behaviour.

The Division further notes a specific inadequacy in the current causer pays methodology which allows the performance of all participant units to impact a causer pays factor applied to cost recovery for local FCAS requirements, even if those units are outside the region to which the local requirement applies. This is a particular concern in South Australia, which is significantly affected by local regulation FCAS requirements.

To the extent that AEMO's pending draft report and determination do not resolve these issues, the Division would encourage the Commission to consider them further through the review.

The Division also considers that there is a need to reconsider the existing cost recovery arrangements for contingency FCAS. The Commission should consider these arrangements as part of the review ensure the approach captures the amount that a generator contributes to the size of the contingency, and better align generator behaviour with cost recovery.

To require a smaller generator, which may not be contributing to the level of the contingency, to pay the same as a large generator who has a larger impact on the contingency size seems inappropriate. With the cost of market ancillary services increasing, and with the cost of regulation and contingency ancillary services becoming roughly equivalent, there is a case for the cost recovery mechanisms for these services to also be consistent.

A causer pays cost recovery method for contingency FCAS services, with appropriate contribution factors determined for assigning costs of contingency FCAS to those participants who have caused the need for those services, should therefore be considered by the Commission.

Co-optimisation with other markets

Finally, the Division agrees with the Commission that, as levels of inertia decline into the future, any long term market design will need to consider how FCAS can best be co-optimised against inertia, and mechanisms for the provision of an economic level of inertia developed.

Against this background, the Division is disappointed by the Commission's decision not to make a rule in its draft determination for the *Inertia Ancillary Service Market* rule change.[9] However, the Division understands the Commission's reasons, and agrees that there is less urgency associated with introducing a mechanism to facilitate the provision of additional inertia for market benefit following the making of the *Managing the Rate of Change of Power System Frequency* rule change.

Fundamentally, the purpose of a market mechanism for inertia provision would be to price the relevant constraints in in AEMO's NEM Dispatch Engine. The Division understands that AEMO is still working to understand the limits of power system operation with low levels of synchronous capability and is considering how system

[9] AEMC, *Inertia Ancillary Service Market*, Draft Rule Determination, 7 November 2017.

security constraints can be developed.[10] It would not be sensible to seek to develop a mechanism for pricing inertia constraints while there is still uncertainty as to how these constraints would be formulated.

The Division agrees that both operational and market aspects of this issue should be addressed together in a holistic manner, and notes that this is likely to require considerable development work. However, the ability to procure inertia – and co-optimise this against FCAS (including FFR) – will clearly be a fundamental part of the wholesale market of the future.

To this end, the Division would encourage the Commission to consider this throughout its work program. In particular, as the Commission notes, the dispatch of additional inertia can only be achieved by the commitment of extra units (whether generating units or synchronous condensers), which is therefore likely to require day ahead commitment for the provision of an inertia service.[11] As such, this should represent an important consideration in the Commission's assessment of day-ahead market designs in the *Reliability Frameworks Review*.[12]

The Division hopes that this submission is helpful in allowing the AEMC to further progress its work in this important area.

Should you wish to discuss the submission in further detail, please contact Mr Andrew Truswell, Director – Energy Transformation, Energy and Technical Regulation Division on (08) 8226 6554.

Yours sincerely

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[10] Ibid, p. ii.
[11] AEMC, *Frequency Control Frameworks Review*, Issues Paper, 7 November 2017, p. 96.
[12] AEMC, *Reliability Frameworks Review*, Issues Paper, 22 August 2017, p. 66.