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CLEAN ENERGY COUNCIL

5 October 2017

John Pierce, Commissioner
Australian Energy Market Commission
Lodged Electronically

Dear John,

RE: AEMC Consultation on Inertia Ancillary Service Market Rule Change

The Clean Energy Council (CEC) is the peak body for the clean energy industry in Australia. We represent and work with hundreds of leading businesses operating in solar, wind, energy efficiency, hydro, bioenergy, energy storage, geothermal and marine along with more than 4,000 solar installers. We are committed to accelerating the transformation of Australia's energy system to one that is smarter and cleaner.

We welcome the opportunity to provide this submission to the Australian Energy Market Commission (AEMC). As the penetration of renewables and energy storage increases in the NEM, we can appreciate the need to prepare a transition towards a more flexible and adaptive ancillary services market. The CEC understands that the AEMC intends for three levels of 'inertia' to be put in place to support a secure system and the market benefits of inter-regional trade:

1) Minimum Threshold (MT) which permits a stable response in the region following the loss of inertia provided through an 'interconnector' to a sub-network, assuming low power flows.
2) Secure Operating Level (SOL) which would be set at a level to permit the region to withstand the next largest credible contingency following islanding.
3) Market Benefits (MB) level which would permit increased trade between regions by alleviating rate of change of frequency constraints that would otherwise be placed on interconnectors.

The AEMC's recent ruling on the 'Managing the rate of change of power system frequency rule change' determined that Transmission Network Service Providers (TNSPs) will be responsible for the provision of the MT and SOL, with the Australian Energy Market Operator's (AEMO) providing input on where and when the services would be required after

1 July 2019[1]. This present consultation paper is focussing on the Market Benefits or MB component, assuming that the MT and SOL are in place in the sub-network or region. We also refer the AEMC to our submission back to the draft rule change on 'Managing the rate of change of power system frequency'[2] as some of the matters we raised in that submission remain relevant to this rule change.

Overall, we are concerned the proposed solution may be hastily implemented leading to significant unintended consequences. In the first instance, we highlight that the proposed solution is not a market per se, but rather a subsidy provided to synchronous generators. The solution would increase costs to consumers from increased transmission use of system charges and increase opportunities for market power by some generators.

Secondly we highlight that the model is failing to be technology neutral, as it is inconsistent with the decisions and directions made elsewhere by the AEMC in its exclusion of consideration of Fast Frequency Response (FFR). It also appears to be premised on planning for non-credible contingency events, and is only underpinned by a state specific legislative order on AEMO, not a NEM-wide condition. On these matters it is inconsistent with the AEMC's Assessment Criteria.

Third, the recently completed rule changes on system strength, MT and SOL and the initiation of the Frequency Control Frameworks Review are all working on solutions that are closely related to the objective of this rule change. We believe there is a need to delay any further consideration of this rule change until these matters are addressed and implemented. It appears that long-term costs and risks are currently far in excess of undefined benefits. The AEMC should take care to not implement a solution that is not fully considered and holistic.

The key reasons for our concerns are set out below.

Markets should focus on outcomes

As a general rule, markets should focus on the desired outcome, not the means of achieving the outcome. Any market mechanism should be focused on supressing rates of change of frequency (i.e. a "ROCOF suppression service"). Designing markets with technology specific criteria such as 'inertia' can restrict competition and prevent lower cost solutions reducing the overall costs to consumers. Restricting alternative technological solutions from providing a service that can reduce high rates of change of frequency fails to comply with the AEMC's Assessment Framework on technological neutrality[3].

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[1] AEMC, Managing rates of change of power system frequency rule change, Final Determination, June 2017, p. 65.

[2] CEC, Submission to draft determination on Managing rates of change of power system frequency rule change, August 2017.

[3] AEMC, Inertia ancillary services market rule change, Consultation Paper, September 2017, p. 15.

Treatment of Fast Frequency Response

In making the ruling on the 'Managing the rate of change of power system frequency' the AEMC determined that although the MT level could only be provided by mechanical inertia, FFR from non-synchronous plant would be permitted to supplement mechanical inertia to meet the SOL where AEMO agreed. However, in the consultation paper the AEMC appears to be implying that FFR could not substitute inertia to meet the MB component. This direction is inconsistent with the previous rule determination.

The AEMC should clarify why it now has the view that MB levels cannot be met with a combination of FFR and mechanical inertia. Our view is that if this rule change proceeds, it would have to be consistent with the final rule on SOL, in making exactly the same concessions for FFR as a substitute for inertia as with the SOL. This concession is especially important if the MB inertia level is to be delivered through a truly competitive market mechanism.

Planning issues

The development of the MB level of inertia is predicated on the loss of significant interconnector flows (for example, from Victoria to South Australia) being the largest credible contingency event. By nature of their design, interconnectors in the NEM provide redundancy and the loss of a whole interconnector is considered a non-credible contingency[4].

It is worth noting that the credible loss of one interconnector line would reduce power flows, but not reduce inertia provided across the interconnector, so the CEC assumes the proposed market mechanism is effectively planning for non-credible contingency events. This appears to be the case as suggested in the consultation paper[5].

The National Electricity Rules prevent the AEMO from planning for non-credible contingencies so there are presently no ROCOF constraints in place as a result of AEMO's modelling of the system. Similarly, the rules do not contain a system standard that restricts the ROCOF in any part of the NEM.

The NEM's only ROCOF constraint has been put in place by the South Australian government and stated to restrict ROCOF following the non-credible loss of both lines of the Heywood interconnector[6]. This condition is outside of the rules' planning framework.

The AEMC's Assessment Framework for this rule change clearly states that 'regulatory or policy changes should not be implemented to address issues that arise at a specific point in

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[4] With the exception of Basslink which incorporates a special protection scheme in Tasmania to manage system security.
[5] AEMC, Inertia ancillary services market rule change, Consultation Paper, September 2017, p. 11.
[6] AEMO, NEM Constraint Report 2016, June 2017, p 13.

time or in a specific jurisdiction only'[7]. Yet the proposed inertia market mechanism could only be implemented in one jurisdiction, would rely on intervention from a state government and would contravene the rules' planning framework as it is specifically designed to accommodate non-credible contingencies.

Reinforcing the state specific nature of the proposed model is the fact that market network service providers do not receive inter-regional settlement residues through an auction process, so the model must therefore be reconsidered in light of how it is applied to all NEM regions.

The proposed approach is a significant departure from NEM planning, sets a radical precedent for rule changes and cannot work for all NEM regions. It is entirely unclear how the proposed inertia market mechanism complies with the Assessment Framework and the AEMC needs to clarify this prior to moving forward.

Transferring inter-regional settlement residues to generators is a subsidy

Inter-regional settlement residues (IRSR) only accrue as a result of price separation in the presence of constraints that limit inter-regional trade. The AEMC expects that where a ROCOF constraint might be invoked, a market response from synchronous generators in the importing region would increase inertia in this region, which would in turn alleviate the constraint and allow a subsequent increase in the potential flow on the interconnector.

However, alleviating the constraint means that no settlement residues would gather on the interconnector. As a result, the shadow price calculated and paid to synchronous generators would be withdrawn from the general IRSR pool, not specifically from alleviating a ROCOF constraint. In this case the IRSR is reduced twice:

1) For the loss of residues that would have accrued due to the constraint but are not as the constraint has been alleviated.
2) For the payment of a subsidy to the generator at the shadow price equivalent to the loss of residues.

Overall, this has a double impact on the IRSR pool. This outcome highlights that the mechanism is not a market per se as there is no counterparty. Rather it is a redistribution of wealth from the IRSR to synchronous generators in the form of a subsidy.

The AEMC needs to clarify that the proposed solution is not a market at all. Further, the AEMC appears to imply that all synchronous generators online at the time would receive the subsidy[8]. Some would have been generating already so they could not have all dispatched in response to a market signal to alleviate the constraint. This solution creates risk in the form

[7] AEMC, Inertia ancillary services market rule change, Consultation Paper, September 2017, p. 15.

[8] AEMC, Inertia ancillary services market rule change, Consultation Paper, September 2017, p. 19.

inefficient reduction of IRSRs, which are ultimately borne by consumers through increased transmission use of system charges. It is unclear how this outcome fits with the AEMC's Assessment Framework.

Market power issues need further consideration

During the System Security Market Frameworks Review, the AEMC raised serious concerns about the potential for market power to arise when dispatching inertia services alongside energy. In particular in a discussion paper the AEMC notes the following:

> "*Generators provide all of their inertia when they are online or no inertia when they are offline, regardless of energy output. Therefore, any increase in the level of inertia would require the start-up of an additional generating unit. This is different to energy where an incremental increase in the demand for energy can generally be accommodated by an incremental increase in the output of the generating units that are already online. … The relative inflexibility of existing thermal generating plant in terms of start times suggests that care will need to be taken in any market design in order to minimise the ability of generators providing inertia to influence energy price outcomes through rebidding. The integration of inertia in the wholesale energy market may require a unique set of regulations around rebidding activity, such as gate closure to provide time for generating units to come online or possible restrictions on the generating units that are already online to set the spot market price.*"[9]

At that time the AEMC noted that any mechanism that coordinates energy and inertia dispatch would require significant consideration in regards to its potential to facilitate market power for thermal generators[10]. The CEC recognises that this proposal does not specifically coordinate generator dispatch based on price and inertia. Rather it simply subsidises synchronous generation. However, we would expect a similar consideration of potential market power issues.

Constraints invoked in South Australia over the last two years have led to major cost increases. For example AEMO's local sourcing of regulation FCAS has opened up an opportunity for the cost of regulation raise and lower services to reach nearly $100 million in South Australia since the constraint was put in place in October 2015. It is now well documented that despite significant capacity to provide the service, a lack of competition is a key driver behind the increased regulation costs.

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[9] AEMC System Security Market Frameworks Review, Information paper for the system security technical working group, February 2017, p. 14.
[10] Ibid.

Similarly, AEMO's fault level constraint requires a specific number of synchronous generators online alongside 1200 MW of wind generation. The curtailment of wind production in South Australia has already been demonstrated to increase dispatch prices in the region. High wind generation supresses prices significantly. However the dominance of gas generation when the constraint binds leads to higher dispatch prices[11] increasing the costs to consumers.

Rather than rewarding the marginal generator for its actions to alleviate the constraint the AEMC appears to intend that all providers of inertia in a region are paid for the service[12]. The issue with simply paying a subsidy to synchronous generators is that there will be no connection between behaviour in the market and the payment. On the basis of available evidence this outcome would significantly increase wholesale market prices, especially in South Australia which is a concentrated market with high levels of vertical integration and low fuel diversity.

Available experience should serve as a stark warning against hastily implementing a new technology-specific subsidy as proposed. Uncompetitive market outcomes should be expected and analysed in detail prior to proceeding with the proposed solution.

Generator ROCOF withstand capability must be known to provide inertia services

In the draft decision on the 'Managing the rate of change of power system frequency' rule change, the AEMC noted that the ROCOF withstand capability of generating units commissioned prior to 2007 is undocumented and largely assumed based on experience (although operating point influence on ROCOF withstand capability remains unknown). Inertial contribution from these units to contribute in a market requires greater confidence in performance, given the fundamental nature of system security.

It is unacceptable that generating units within unknown or undeclared ROCOF withstand capability might contribute to inertia levels to support a secure power system. The National Electricity Rules must be clear that only a Registered Participants' generating units with clearly stated and confirmed ROCOF withstand capability may register as inertia service providers. Testing must be a requirement register for those units commissioned prior to 2007.

Interfaces with the MT and SOL

In the final determination of the 'Managing rates of change of power system frequency' rule change the AEMC determined that a TNSP can fulfil its obligations for the MT or SOL by contracting with generators. This outcome has not been considered in the consultation paper. Should generators already contracted also expect receive a subsidy from the IRSR, or

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[11] http://www.wattclarity.com.au/2017/09/how-much-wind-powered-electricity-production-has-been-curtailed-in-sa-since-these-new-constraints-were-invoked/

[12] AEMC, Inertia ancillary services market rule change, Consultation Paper, September 2017, p. 19.

would the rule change explicitly exclude this double payment? Would these same generators also expect a payment to tighten their governor deadband settings? These matters require a holistic view of the issues.

Summary

In summary we do not believe this proposal is consistent with the proposed assessment framework, and expect that it will increase costs and open up market power opportunities for generators in South Australia. In light of other recent changes associated with system security and the ongoing work in the AEMC's Frequency Control Frameworks Review (such as mandating governor deadband settings) there is a need to delay any further consideration of this rule change as it appears to present long-term costs and risks far in excess of undefined benefits.

We trust that this submission assists the Commission in its deliberations and welcome continued discussion of important issue. Please contact the undersigned or Emma White (03 9919 4107) for any queries regarding this submission.

Sincerely,

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