13 October 2016

Chris Spangaro
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Australian Energy Market Commission
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Dear Chris

Re: System Security Market Frameworks Review

Thank you for the opportunity to respond to the Australian Energy Market Commission's (AEMC's) System Security Market Frameworks Review Consultation Paper. We understand that the AEMC's Review will identify the changes to market and regulatory frameworks that will be required to deliver the technical solutions identified by the Australian Energy Market Operator (AEMO). These changes may include, but are not necessarily limited to, different mechanisms to competitively procure the required system security services, possible changes to standards or the establishment of new standards, or changes to the roles and responsibilities of market participants.

The importance of the AEMC's work in this area has been heightened by the recent black system event in South Australia on 28th September 2016. After the black system event, the COAG Energy Council held an extraordinary meeting in which they agreed that Government's "primary responsibility is to ensure the security, reliability and affordability of the energy system for all Australians."[1] Stanwell endorses this COAG statement. With respect to the affordability of energy, it is disappointing that Australia has moved from one of the lowest cost electricity nations to one of the highest cost, to the detriment of Australian industry and economic growth.

With respect to security and reliability, renewable energy policies have emphasised "energy" while neglecting to value the other electricity market services which are required to maintain a secure and reliable electricity supply. This has led to the weak system and instability problems in South Australia. The current National Electricity Market (NEM) was designed over 10 years ago with the underlying assumption that electricity market services are provided at no cost by synchronous generators. Now that there is little synchronous generation in South Australia this assumption needs revisiting.

Relationship with other regulatory processes

[1] COAG Energy Council Meeting Communique, 7 October 2016

The AEMC's review is interrelated with other current reform work. This includes the AEMC's five minute settlement proposal, the proposal for demand to bid into dispatch and the AER's approach to compliance with dispatch instructions.

The five minute settlement proposal[2] would incentivise generator response which could be delivered within five minutes ahead of generator response which requires longer lead times. Under normal conditions, most peaking plant require time to synchronise to the grid[3]. Stanwell is concerned that a market design which does not appropriately incentivise peaking generators is unlikely to be sustainable. This is especially concerning as peaking generators are considered to be essential to support the transformation to a renewable energy future.

In addition, if the 5 minute settlement proposal incentivises large amounts of very fast response, this is likely to add to existing difficulties in managing system frequency. The problem will be exacerbated if this fast response is provided in a non transparent, non predictable manner. This is precisely what will happen if large loads and new technologies are not required to bid into dispatch or register as generators.

AEMO has listed visibility of the power system as a high priority challenge requiring increased information from market participants. Stanwell believes that the proposal for large, price responsive demand and non-scheduled generators to bid into central dispatch[4] would assist AEMO to better manage the power system. The proposal would provide AEMO with increased transparency on market participant behaviour and therefore the ability to produce more accurate pre-dispatch forecasts and dispatch outcomes. The proposal would not however assist in providing transparency to AEMO in relation to the behaviour and characteristics of aggregated small loads, storage devices and small generators.

The AER has recently entered into a court enforceable undertaking with CS Energy[5] in relation to compliance with Rule 4.9.8 of the NER. In the undertaking, CS Energy explains that the relevant generators were set to inversely change output level in proportion to system frequency. This occurred automatically notwithstanding that the units had not been instructed by AEMO to provide regulation FCAS.

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[2] http://www.aemc.gov.au/Rule-Changes/Five-Minute-Settlement

[3] For example, Mt Stuart Units are typically offered with a requirement for 18-21 minutes between the receipt of a start signal and the first energy being exported. Some peaking generators are kept synchronised but not exporting in order to provide a fast response, such as Kareeya Power Station. Such a regime is typically not costless and is a commercial decision by the provider.

[4] http://www.aemc.gov.au/Rule-Changes/Non-scheduled-generation-in-central-dispatch

[5] https://www.aer.gov.au/wholesale-markets/enforcement-matters/infringement-notices-issued-to-cs-energy-and-enforceable-undertaking-failure-to-follow-dispatch-instructions-and-offer-obligations

As a result of the settings on CS Energy's units, CS Energy was providing frequency services to the market at no cost to participants. This is the manner in which many synchronous generators operated in the past, both for efficient operation and to minimise FCAS causer pays charges. Since the investigation by the AER, Stanwell understands that multiple generators have now changed their settings so as to prevent automatic deviations in response to changes in system frequency. This action has therefore resulted in less automatic frequency control inherent in the NEM. In this environment, it is important that markets are designed to appropriately value frequency services.

Inertia

It appears from AEMO's work that inertia is the most important characteristic that is missing from non synchronous generators. With adequate system inertia South Australia would not be reliant on the Heywood interconnector for secure operation. With adequate inertia there would not be a need to consider a new "protected" contingency event category and no need for consideration of a fast frequency response market. It appears that policy makers should prioritise regulatory frameworks to incentivise the provision of inertia.

It is Stanwell's understanding that inertia is best provided by synchronous generators and synchronous condensers. "Synthetic inertia" appears to be costly in that it constrains back the energy output of the windfarm in order to be ready to provide a response. In addition it must be used in conjunction with other fast acting responses. AEMO have said "at present, synthetic inertia has not been demonstrated to be an exact substitute for mechanical inertia"[6].

Stanwell notes that there are synchronous generators in the NEM that are currently being retired but, with an appropriate incentive, could continue to be available as synchronous condensers. This would ensure their inertia was not lost, even if their energy was replaced by energy derived from non synchronous renewable energy.

As synchronous condensers could be provided by either a generator or a network, the regulatory framework must ensure that the most efficient solution is implemented. This means that both participant types should be able to compete on an equal basis to the same regulatory funding and/or markets. This proposal would only be effective if the network businesses were subject to appropriate ring fencing of the competitive and regulated parts of their businesses.
With respect to the type of framework that is required to incentivise the provision of inertia, Stanwell believes that long term incentives are required. For a retiring synchronous generator or a network to provide synchronous condensers, a non trivial investment in infrastructure is required. This requires a long term certainty of return. In addition, if inertia was adequately compensated, this may delay the retirement decisions of synchronous generators. This is unlikey to occur if the provision of inertia was only provided with a short term incentive.

[6] Page 25, Future Power System Security Program, AEMO

A long term inertia incentive is best achieved by either a technical obligation on new (or possibly even existing) participants to provide inertia or a long term contracting process run by AEMO. A technical obligation on participants has numerous advantages as the approach:

- appropriately acknowledges that for system security the market needs both energy and inertia - current renewable energy policy focusses only on energy and neglects inertia to the detriment of system security
- appropriately allocates the risk and accountability for investment decisions to those parties who have – or will - cause the "problem" and who are best placed to manage the provision of inertia by incorporating it into their investment decisions. By contrast a centralised planning arrangement means risk is more likely to be borne by customers.
- does not give rise to inefficient signals or cross subsidies compared to an approach where synchronous generators or customers are charged for inertia.
- allows for the efficient provision of inertia - a non synchronous proponent would evaluate the cost of providing inertia itself (through synchronous condensers or synthetic inertia) versus the cost to contract inertia from synchronous generators or others with available inertia
- allows for the long term provision of inertia
- provides solutions on a technology neutral basis
- would continue to be effective through continued changes in technology and market conditions

Protected events

The AEMC is considering whether along with the categories of credible and non-credible contingencies there should be another category of contingency possibly known as "protected" events. These events would cover a subset of non-credible contingencies that, if they occurred, would have a significant impact. Stanwell expects that the Reliability Panel (potentially in consultation with Jurisdictional System Security Coordinators) would define the protected events and would specify a standard to which AEMO must manage the system, should a protected event occur. Initially, Stanwell understands that a protected event is likely to be the double circuit outage of the Heywood interconnector and management could involve constraining the interconnector, procuring local Frequency Control Ancillary Services (FCAS) and/or constraints on certain types of South Australian generation.

This approach appears to broadly sensible, especially as a short term, interim solution. Our preference is for the AEMC to prioritise developing an appropriate framework for inertia which would likely negate the need for the new category. We also note that introducing a new category will lead to increased ongoing costs and may lead to inefficient use of existing generators and networks. The recent cost of local South Australian FCAS requirements demonstrates how expensive this approach could be. Given the potential for significant costs, it will be important to explore and provide clear guidance as to how the costs are to be recovered and from whom.

If a new mezzanine category was introduced, consideration could also be given to reclassifying some credible contingencies as protected events. These may be events that are reasonably likely to occur but that would have a low impact if they did occur.

As an alternative, consideration could be given to whether the existence of multiple risk factors, each one on their own considered non-credible, should constitute a credible contingency. This approach may have helped prevent the recent South Australian blackout when multiple non credible risk factors were present: high winds and lightning, high imports on the interconnector and a large proportion of non-synchronous generation online.

Rate of Change of Frequency (RoCoF) standard

Presumably AEMO can already estimate the potential RoCoF should a contingency occur – indeed if this were not the case then a RoCoF standard would not work. If AEMO can already estimate RoCoF then AEMO can already determine whether a contingency would lead to a breach of the Frequency Operating Standard (FOS). As AEMO already manages the system to stay within the FOS it appears that a RoCoF standard may be a superfluous subset of the FOS.

Thank you for consideration of Stanwell's response to the System Security Market Frameworks Review Consultation Paper. If you would like to discuss any aspect of this submission, please contact Jennifer Tarr on 07 3228 4546.

Regards

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Energy Trading and Commercial Strategy