Hydro Tasmania
The power of natural thinking

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John Pierce
Chairman
Australian Energy Market Commission (AEMC)
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By online submission

Dear Mr Pierce

System Security Market Frameworks Review – Interim Report

Hydro Tasmania welcomes the opportunity to provide a submission on the AEMC's System Security Market Frameworks Review Interim Report.

The energy market is undergoing a significant period of transformation which is bringing a number of challenges for the National Electricity Market (NEM). The AEMC's System Security Market Frameworks Review provides a timely and valuable opportunity to address the current challenges and realign the market for the future. In addressing these challenges, Hydro Tasmania suggests that the AEMC should consider defining a set of criteria which would be used to evaluate the various options that are being considered. These core criteria might include:

- Cost to market/customers.
- Certainty of outcome.
- Adaptability to changing market circumstances.
- Risk to market.
- Technical criteria (relevant to the service).
- Ease of implementation (and timeframe if necessary).
- Administrative simplicity.

It is important also that market frameworks are robust to adapt to changing and new technologies and can adequately accommodate a greater penetration of renewable energy over the long term. In considering ways to address the transition to integrating greater levels of renewable energy, Hydro Tasmania believes that the full range of measures should be considered including the use of System Protection Schemes (SPS) to reduce contingency size to manage selected credible and non-credible network contingencies. SPS offer an enhanced way of managing credible and non-credible contingency events, for example, in the event of an instantaneous tripping of an interconnector and effectively provides for a reduction in in contingency size. A reduction in contingency size can be one of the most cost effective ways to manage system frequency and associated Rate of Change of Frequency (ROCOF). Hydro Tasmania believes consideration should be given to ways in which support for reducing contingency size could be achieved through the existing Network Support

Control Ancillary Services (NSCAS)/network provision framework or as regulated networks assets. This could include use of SPS including for Emergency Frequency Control Schemes (EFCS).

While the Interim Report proposes establishing two separate market mechanisms for inertia and Fast Frequency Response (FFR), Hydro Tasmania suggests that there is merit in the AEMC considering establishing a single market mechanism which incorporates inertia and FFR. As the Interim Report notes, there are some small differences between rotating inertia and FFR including an initial time delay required by FFR to respond to the disturbance. These differences need to be considered in full to understand the potential impact on the market. However, both inertia and FFR are essentially different ways to address the same issue – a frequency disturbance following a system event. The single market mechanism could reward the value the service provides in responding to the frequency disturbance. Inertia for example, is most valuable instantaneously following an event when other control mechanisms have not been activated; however this contribution is limited in time and oscillatory reflecting changes in ROCOF. FFR provides fast response with short delay due to activation outside normal operational frequency band (NOFB) but FFR contribution can be sustained longer than inertia and it could be designed to provide faster recovery. A single market mechanism would provide a platform for all technologies to compete (both rotating generators providing inertia and energy storage devices providing FFR).

The requirement for system inertia/FFR varies over time and between regions. Depending on the system conditions at the time, there may not be a requirement for system security services in addition to those being supplied in the market provided system frequency is being managed within the Frequency Operating Standards (FOS). For example, you would not want to create a requirement for inertia in Victoria, with associated market costs, where there is plentiful inertia already present. The mechanism will need to be flexible to accommodate these variations while still appropriately rewarding provision of these services.

The Interim Report outlines four broad mechanisms for the provision of additional system security services through generator obligations; AEMO contract process; TNSP provision and five-minute dispatch. Hydro Tasmania notes that each of the potential four new mechanisms are potentially feasible with each having both positive and negative attributes. Consistent with the principles outlined above, Hydro Tasmania suggests the AEMC needs to develop a view around the ease of implementation (including timeframes) and likelihood of succeeding – both technically and administrative simplicity. This could include a hybrid approach to some or all of the options outlined in the Interim Report. Based on an initial assessment of the four proposed mechanisms Hydro Tasmania believes that the following prioritised order could be a practical approach to reform:

1. NSCAS network provision: This mechanism currently exists and Hydro Tasmania believes it is not being exploited to its full potential and are predominately backward looking not catering for future system security issues or current operations that enhance the performance of the network. Prior to establishing new regulatory requirements or markets, a detailed examination should be undertaken of the appropriateness of existing NSCAS measures (like calculating the NSCAS gap) to meet system security issues. This mechanism is also suitable to manage the system strength if required.
2. AEMO contract process: It is Hydro Tasmania's view that the proposed AEMO contracting process could be similar to the NSCAS network provision option (and AEMO is the procurer of last resort in any case) with less TNSP involvement. However, the TNSP will most likely have a role to play in developing a solution through the AEMO contract process.
3. Market solution: a market solution may ultimately drive the most efficient outcomes, however this approach would be a medium to long term solution given that technologies

need to be trialled and operated before markets can be developed to support their efficient deployment.

4. Generator Obligation: Hydro Tasmania believes there is merit in emerging technologies being exploited where possible. There may not be current 'market value' in requiring new connecting generators (predominately inverter based) to have enhancements such as fast frequency response. However there may be long term value having this capability available and it will help manage system security upon being implemented. It is also Hydro Tasmania's view that it is much more difficult and costly to retrofit enhancements to already installed infrastructure (existing infrastructure could be grand fathered); while an obligation on new entrants to make minor enhancements may be more manageable and less costly. This option has many dimensions and Hydro Tasmania acknowledges this could be very hard to implement but could be implemented as a partial component of managing overall system frequency and associated ROCOF.

In considering the broad transformation of the energy system that is currently underway, Hydro Tasmania would like to highlight several emerging issues with minor frequency variations with reduction in synchronous generators, traditional governor response and system inertia. These issues may not be specifically in the scope of the AEMC's system security review but will need to be considered over time and potentially through processes such as AEMO's review of the Market Ancillary Service Specification (MASS). These include but are not limited to:

- Delivery of regulation frequency control (FCAS) from new technologies.
- Increased variability of generation in short timeframes and impact on system frequency.
- Load fluctuations with a lighter system and system frequency.
- Less traditional generator governor response.
- Automatic Generation Control (AGC) management, effectiveness and verification/testing including Regulation FCAS.
- Interaction between contingency services (conflict between primary vs. secondary response).
- Deadbands being applied to modern, digital control systems to match specific standards and/or to reduce burden on generating plant while not supporting the power system.
- Requirements for droop characteristics on frequency control systems and the impact of withdrawing governor response.
- Implications to aforementioned issues on 'causer pays' principals.

Please contact John Cooper (john.cooper@hydro.com.au or (03) 6230 5313) if you have any questions

Yours sincerely

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