Government of South Australia
Department of State Development

*In reply please quote #A848633*

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

**System Security Market Frameworks Review – Consultation Papers**

Dear Madam/Sir

The Energy Markets and Programs Division of the Department of State Development, South Australia (Division) welcomes the timely System Security Market Frameworks Review (Review). Please find attached two submissions; a submission on "System Security Market Frameworks Review and related rule change requests" (1st consultation paper) and another submission on "Emergency under frequency control schemes and emergency over frequency control schemes rule change requests" (2nd consultation paper).

As mentioned in several places in both consultation papers, South Australia in particular is experiencing a steady change in generation mix presenting challenges to the management of power system security in the region under certain conditions and at different locations within the region. The characteristics of the increasing levels of non-synchronous intermittent generation and the 'blocked-size' exiting of conventional synchronous generation across the State have already presented challenges that are expected to continue into the foreseeable future.

As a result, the South Australian Government is keen to see the advance of the related four rule change requests it submitted on 18 July 2016. The Division sees a pressing need to have the necessary flexibility in the National Electricity Rules (Rules) for the Australian Market Systems Operator (AEMO) to be able to manage system security challenges in both the short and long terms. In this regard, the Division considers that any proposed immediate solutions should not necessarily overshadow the desired medium and long term outlook for South Australia and the National Electricity Market (NEM) as a whole.

In each submission, the Division addresses the different questions and issues presented in the consultation paper under the relevant project reference code (as per the instructions in the consultation paper). The submission on the 1st consultation paper has a special focus on the two relevant South Australian Government rule change proposals covered by this Review (referred to 'SA A' and 'SA D' in the first consultation paper). The two other rule change requests by the South Australian Government regarding Emergency Frequency Control Schemes (referred to 'SA B' and 'SA C' in the 1st consultation paper) are covered under the submission to the 2nd consultation paper for Emergency Frequency Control. However as discussion topics are often interrelated, some references to the topics related to rule changes in one submission will inevitably be cross-referenced in the other submission.

The Division hopes that its submissions will help the Australian Energy Market Commission (AEMC) facilitate the consultation on the rule change requests and will assist with the progress of its system security work program.

Should you wish to discuss the details of the submissions further, please feel free to call Ms Rebecca Knights, Director - Energy Markets and Programs Division, on (08) 8226 5500.

Yours sincerely

**Vince Duffy**

**EXECUTIVE DIRECTOR**

21 October 2016

# System Security Market Frameworks Review

**Submission to Consultation Paper**

Energy Markets and Programs Division, Department of State Development

South Australia

October 2016

## EPR0053 – System Security Market Frameworks Review

The Division supports the collaborative approach with market agencies that the AEMC is taking in conducting the Review, in particular, as stated in the consultation paper, the identification of the necessary changes to market and regulatory frameworks that will be required to deliver the best available and proven technical solutions recommended by AEMO.

Considering the urgency for South Australia, the Division is encouraged by the statement in the Review that the AEMC will consider the relevant rule change requests alongside undertaking the Review. Within the purpose of the Review, the Division emphasizes the need for practical mechanisms that can be implemented in the immediate future to competitively procure the required system security services, change or establish new standards, or clarify responsibilities, all for the purpose of maintaining relevant system parameters within secure limits.

The Division envisages the outcome of the Review to be a range of options that can be implemented in different timeframes vis-à-vis cost efficiency for each option. This may assist in the assessment of cost-risk tradeoff, especially in the case of South Australia to be able to meet its system security requirements.

### 4.3 Procurement of additional system security services

#### 4.3.1 Procurement options

**Question 5**

Do you consider it beneficial to establish new mechanisms for the procurement of additional systems security services?

What form of mechanism do you consider to be preferable and which services should the mechanism be targeted at?

The three existing procurement mechanisms stated in the consultation paper (technical obligations on market participants, contract tender processes and five-minute procurement through the NEM dispatch engine) are considered adequate to cover all possible means of providing additional system security services in the near future.

Referring to the case presented in the consultation paper, a lowest cost arrangement for the preferred service or a combination of services (whether through one or two mechanisms) to meet the minimum standard for RoCoF would be the ultimate solution. However, system simulation studies and testing of asset capabilities (whether existing or new technologies) to provide the service may be key factors to consider when selecting the most preferred mechanism.

A major concern for the Division is the time frame required before a mechanism is ready for implementation. It is envisaged that some long-term solutions would be optimal. However, it is important for South Australia, given the urgency, that the time factor is also assigned a cost when assessing different procurement mechanisms.

### 4.3.2 Cost recovery

**Question 6**
What form of cost recovery do you consider to be preferable in the design of a mechanism to procure additional system security services?
Should the cost recovery mechanism be designed to create stronger incentives to provide the required services?

Continuing with the case presented in the consultation paper, it is important to consider the cost of procurement of any additional system security service against the cost of the impact of a frequency event that would eventuate if these services are not procured. In this regard, it is essential to consider the nature and likelihood of the event each service is targeting. The cost to the community in the case of emergency services being used to recover from a major security event should also be taken into account when calculating cost. Cost recovery can then be regarded as an insurance premium against incurring major costs if additional services are not procured and a security event occurs.

Traditionally inertia has been provided for free in conventional power systems with plenty of online synchronous generators and some synchronous condensers. With the increase in non-synchronous generation it may be now appropriate to place a value on inertia.

Not providing inertia or fast frequency response (can be thought of as synthetic inertia) can be the basis for equivalence arrangements to purchase such services from elsewhere. Alternatively, each generator can be allocated a responsibility for maintaining RoCoF. The centrally procured inertia or fast frequency response by AEMO can be paid for by all non-contributing or partially contributing generators in proportion to the shortfall by each generator not providing these services using its own assets.

Similarly, with respect to the issues with system strength, localised costs should be apportioned according to the contribution to minimum fault levels in the affected area. Again, as for inertia, fault level contribution was considered a free service in traditional systems. However, now with the scarcity of the resources providing such service, it is may be appropriate to place a value on it to maintain system stability. Depending on nominal bus voltage and the level of contribution to fault level expected by each generator at a connection point, non-contributing or partially contributing generators would be sharing the cost of centrally procured services to meet the required minimum fault level.

### 2.3.1 Managing power system frequency

**Box 2.2 Current frequency issues in South Australia**
Investigations undertaken through AEMO's Future Power System Security Program have shown that the initial challenges of restricting high rates of change of frequency are most acute in South Australia.

**Question 1**
Do you consider that the issues outlined above cover the matters that need to be considered going forward in managing changes in system frequency?

To emphasize the issues mentioned in Box 2.2 of the consultation paper, the Division recognises the challenges resulting from higher rates of change of frequency (RoCoF).

It is important to define the two factors at play that cause the higher values of RoCoF at any time immediately after a contingent event, as follows:

- Decreasing levels of system *inertia* provided by online synchronous generation.
- Increasing size of the *contingency* that would result after the recent upgrade of the Heywood Interconnector, should a failure of the link to Victoria via the interconnector occur.

Looking into the future, AEMO's Electricity Statement of Opportunities published in August 2016 suggests that all of the committed projects, and the majority of proposed projects, in South Australia are all non-synchronous forms of generation. Hence, the system inertia factor is likely to prevail.

The linear relationship between inertia and contingency size, in Box 2.1 of the consultation paper, clearly explains that both factors contribute to the initial RoCoF and could provide some indication on what type of frequency control service that would be required to control RoCoF (a graphic form of this relationship is shown in Figure 1 in the Appendix). For example, for a desired RoCoF of 1 Hz/second and an available inertia of 10,000 MW.sec, the contingency size (or equivalent loss/gain of power) in the region cannot exceed 400 MW. Conversely, a sudden loss/gain of 400 MW of power as a result of a contingency would require a minimum inertia of 10,000 MW.sec so that a limit of 1 Hz/Sec for RoCoF is not to be exceeded.

It is important to note that current levels of inertia in South Australia are adequate to deal with the highest possible contingency size in the state, as long it is still AC-connected to the rest of the National Electricity Market (NEM). A failure of a single line on the Heywood Interconnector, while there is an outage on the other line, is considered as a credible contingent event. Current measures adopted by AEMO to deal with this situation ensure that RoCoF remains within manageable limits.

The sudden and unexpected simultaneous failure of both lines on the Heywood Interconnector is currently considered a non-credible contingency, which is the cause of concern for unmanageably high values of RoCoF. As stated in the consultation paper, there is no provision in the Rules for procuring ancillary services for non-credible contingent events. However as also stated in the consultation paper, the Rules specify that AEMO is obliged to return the power system to a secure operating state following <u>any</u> contingency event, including non-credible contingency events. AEMO relies on emergency measures to comply with such standard as a 'backstop' to prevent a cascaded failure and possible system blackout.

The Division is concerned that emergency measures may not be able to cope with the expected unmanageably higher values of RoCoF, if and when they arise, because:

- In the case of a sudden drop in frequency, AEMO must rely on the operation of the under-frequency load shedding scheme, which studies by AEMO have suggested that it may not be sufficient at higher RoCoF levels. Issues with this scheme are addressed by the Division in a submission to the consultation paper for Emergency Frequency Control in response to the South Australian rule change request regarding Emergency Frequency Control Schemes (generator deficit events) and referred to as 'SA B' in the consultation paper.

- In the case of a sudden rise in frequency, there is currently no coordinated over-frequency generator shedding scheme in place in the case of a non-credible loss of the interconnector that would cause high RoCoF levels. Issues of this nature are addressed by the Division in a submission to the consultation paper for Emergency Frequency Control in response to the South Australian rule change request regarding Emergency Frequency Control Schemes (excess generation events) and referred to as 'SA C' in the consultation paper.

### 4.1 Roles and responsibilities and the establishment of standards

**Question 3**
Do you consider it beneficial to set a standard for RoCoF? What format should this standard take and what factors should be taken into account when setting the standard? Who should set it?
Would the establishment of a new standard trigger significant additional costs to comply?

At present, there are no active mechanisms to steer the power system to operate within the RoCoF limits stated in the access standards for generators. As proposed by the South Australian Government in its rule change request, referred to as 'SA A' in the consultation paper, a system standard for RoCoF may assist in the active management of power system security and can be used to clarify the guidelines for ancillary service providers on how to meet such standard.

Current arrangements in the Rules require generators to comply with certain standards for RoCoF before they can connect to the grid. For the minimum access standard, the Rules require generators to stay connected as long as RoCoF stays within the range of -1 Hz/sec to 1 Hz/sec limits. If this RoCoF limit is exceeded for more than one second, the generator is not obliged to remain connected even if the system frequency is still within the normal operating band or the prescribed tolerance limits (depending on the condition defined in the frequency operating standards). The same applies to the automatic access standard for the +/- 4 Hz/sec limits, but in that case the generator is required to stay connected for only 250 milliseconds.[1]

Similar to the frequency operational standards, the RoCoF standard could have operating ranges within which all assets connected the network are expected to safely operate. Acceptable durations

[1] Rule S5.2.5.3 in The National Electricity Rules, Version 82

of any deviations from the normal operating range would be determined by system studies. It may be desirable to set a different operating range for an islanded region compared to the overall interconnected system. As RoCoF may be affected by transient spikes in frequency measurement when there is no contingent event, it may also be necessary to define in the Rules the method of measurement of RoCoF and the means of measuring compliance.

Factors that can be taken into account when setting a RoCoF standard will largely depend on not just the nature of the current power system, but also on how the future power system would look like, given the rapid changes in the roles played by both generation and load. Examples of such factors could be:

- The configuration of the power system and how that may evolve in the future;
- Capability of assets connected to the electricity network and how new technology may change those capabilities; and
- Adequacy of emergency frequency control schemes (such as UFLS) and the costs of upgrading existing schemes or establishing new schemes to cope with the RoCoF limits set as standard.

As stated in rule change request 'SA A', similar to their current role in setting frequency and other standards, the Reliability Panel would be the appropriate body to establish a RoCoF standard. This standard may have to be changed from time to time to take account of how the power system evolves.

It is acknowledged that compliance cost will be incurred with any new standard. However, asset owners required to meet the new standard are best placed to determine such costs. The total combined cost will need to be taken into account and how the cost is divided between market participants' obligations and centrally procured services.

**4.2 Additional system security services**

**Question 4**
What roles do you consider services such as inertia and fast frequency response should play in maintaining system security in the NEM? How else could RoCoF be managed?

Increasing system inertia or employing devices of fast frequency response to reduce a size of a contingency have a primary role to manage RoCoF. Services available for providing either solution or a combination of both are best determined by system studies on the basis of cost-efficiency trade-off.

Although inertia will always be superior to counteract frequency rise or fall in terms of instantaneous and continuous response, fast frequency response to arrest the initial fall in frequency within the first second of falling will give the synchronous generator governors (6 seconds contingency FCAS) the time to act.

Examples of providing inertia are well known and include synchronous generation at minimum load, synchronous condensers or generators connected to the network spinning in synchronous condenser mode.

In the realms of fast frequency response services, the Division agrees that there are many conceptual local technologies for detecting and responding to frequency deviations, as stated in page 15 of the consultation paper. Some of the applications of such technologies are already operating commercially in some overseas jurisdictions, such as in the New Zealand Fast Instantaneous Reserve market, as follows

- Interruptible load triggered by under frequency relays within one second can play a major role in arresting frequency drops. This application typically uses a large industrial load; and
- Modified speed governor response from partially loaded synchronous generators triggered by a drop in frequency below a minimum frequency threshold to achieve faster response compared to the automatic free governor action. This application is similar to generators operating in a synchronous compensator mode waiting for a trigger to generate power into the grid.

Other applications have been widely discussed in the literature and include:

- Fast action battery storage discharging in response to an under-frequency event from a fitted under frequency relay; and
- Distributed aggregated load shedding with micro-loads tripped in unison by local frequency sensitive relays in response to high RoCoF or a set minimum frequency.

Other measures where high RoCoF can be managed vary depending on the implementation timeframe and cost. One solution is to prevent islanding of a region causing high RoCoF in the first place by having a redundant AC interconnector. Conversely, another solution could be modifying existing or establishing new under frequency load shedding schemes (UFLS) and over frequency generation shedding schemes (OFGS) to be triggered as high RoCoF is detected. Both such measures are not considered within the scope of this review.

### 2.3.2 Managing power system strength

**Question 2**
What do you consider to be the issues associated with low power system strength?

It is important to emphasise the factors affecting system strength. As stated in the consultation paper, the higher the penetration of non-synchronous generation the weaker the system and the less able it is to withstand short-circuit faults. With the proportion of non-synchronous increasing at the expense of synchronous generation, fault currents (also known as fault levels) at certain points in the network will be reduced (traditionally those points are experienced in remote connection points). As stated in the Future Power System security Report published by AEMO in August 2016, synchronous generation contributes typically 3 to 5 times more fault level that non-synchronous generation.

Wind turbines, considered a type of non-synchronous power electronic connected (PEC) generation technology, constitute the bulk of new generation in South Australia. According to the joint AEMO-ElectraNet report on renewable energy integration in South Australia published in February 2016, inherent in this technology is the reaction of wind turbines when a transmission fault occurs. Based on the type of wind turbine, the turbine typically switches to 'fault ride through' mode once it detects a fault. This mode results in the wind turbine reducing its active power output to stay connected during and after the fault. Whilst fast active power recovery is generally desirable when connecting to strong transmission networks, too fast active power recovery can lead to network stability issues and deteriorating voltage recovery when connecting to weaker systems[2]. While active power recovery varies with the type of turbine (the newer the type, the faster it can recover), there is no requirement on wind turbines to maintain pre-fault output during a fault.

In addition to loss of active power, wind turbines traditionally draw a large amount of reactive power from the network to regenerate the field of its induction type generator necessary to convert mechanical to electrical energy. If there is insufficient reactive power available, a localized voltage collapse could occur. Fast reactive power or voltage control can be achieved by using fast acting support plant such as STATCOMS. Newer types of turbines can provide fast turbine-level voltage control independent of the active power control function. Hence, in addition to the problem of active power restoration in the recovery process from fault conditions, there is also the challenge of transient voltage recovery, which requires careful consideration of adjustments needed to manage post-fault active and reactive power recovery strategies.

A combination of poor voltage stability and low Short-Circuit Ratio (SCR)[3] will result in PEC devices struggling to stay connected to the network during a nearby fault. These same factors also make it difficult for such devices to achieve steady state in system normal conditions. AEMO's National Transmission Development Plan, published in November 2015, states that the minimum weighted SCR (as a result of contribution of all wind farms) at a connection point should be 1.5 to 2.5.

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[2] Details of the low voltage ride through capability of different types of wind turbines is detailed in section 5.2 in AEMO's "Wind Turbine Plant Capabilities Report: 2013 Wind Integration Studies", June 2013, p. 5-4.

[3] SCR is defined as the ratio of the power system fault level at the generation connection point (measured in MVA) to the rated generation megawatt.

Maintaining the minimum ratios in points of low synchronous generation will be a limiting factor in the amount of wind generation able to connect to those points on the network.

With regards to current regulatory arrangements relevant to low fault levels, NEM and jurisdictional obligations are summarised, as follows:

- The current Rules (NER S5.2.3(a)(7)) have connection standards in respect of each new and altered generation connection to coordinate fault levels and fault clearance between the Generator and Network Service Provider. It is worth noting that, for embedded generation, the Rules (NER S4.A(a)(5)) state that existing maximum and minimum fault levels of relevant local zone substations are required to be provided by the Distribution Network Service Provider in response to a connection enquiry.
- In addition to the Rules of the NEM, the Essential Services Commission of South Australia (ESCOSA) through the Licence Conditions for Wind Generators[4] has adopted State-specific conditions (mainly focused on fault ride through capability and post disturbance voltage recovery) on wind generating plants in terms of:
    - a more stringent standard (higher than the minimum which could otherwise be negotiated under the NER) to fault ride through capabilities in response to disturbances following contingency events (clause 9 of the Electricity Generation Licence);
    - reactive power capability of continuous operation at a power factor of between 0.93 leading and 0.93 lagging at real power outputs exceeding 5 MW at the connection point, on condition that 50% of this reactive power to be on a dynamically variable basis and the other 50% on a non-dynamic basis (clause 10.2 of the Electricity Generation Licence); and
    - the ability to switch to a fast-acting voltage control system during power system voltage disturbances and automatically revert to set power factor or set reactive power mode after the disturbance has ceased.

Whilst issues with high fault levels are known and are readily managed by well understood means, it is becoming increasingly important to determine what minimum fault levels need to be maintained at connection points and HVDC links to meet system performance requirements. The Division is concerned with the implications of a 'weak' system described in several reports and thus leading to serious consequences summarized as follows:

- Protective relays unable to distinguish between system normal load current and fault current, which may require changes in protection systems or even re-designing and replacing such systems;
- Greater risk of DC/AC converters not remaining operational through network faults as they are no longer able to meet their fault ride through capability;
- Inability to achieve steady-state stability during normal system operation conditions; and
- Slow rate of recovery following network faults with the susceptibility of voltage instability or collapse.

[4] Available at http://www.escosa.sa.gov.au/projects-and-publications/projects/electricity/wind-generation-licensing-2010.

Based on the above information regarding the issues and current mitigating measures, the potential range of solutions need to be considered in terms of two key principles:

- Low fault levels represent a localised problem affecting specific connection points on the network. Thus, the sought after arrangements would need to be flexible enough to address the range of issues associated with this problem. At the same time, the solution will need to be distributed in nature and possibly provided by several market participants, depending on the location of points with poor system strength.
- Fault levels are dynamic in nature, as they depend on the type of generator connected at the time. A wind generator which is compliant at time of connection may not be so later as the surrounding assets connected to the connection point vary in type as a result of synchronous generator withdrawal (or being offline) or another wind generator connecting to the network at a later date.

### 4.1 Roles and responsibilities and the establishment of standards

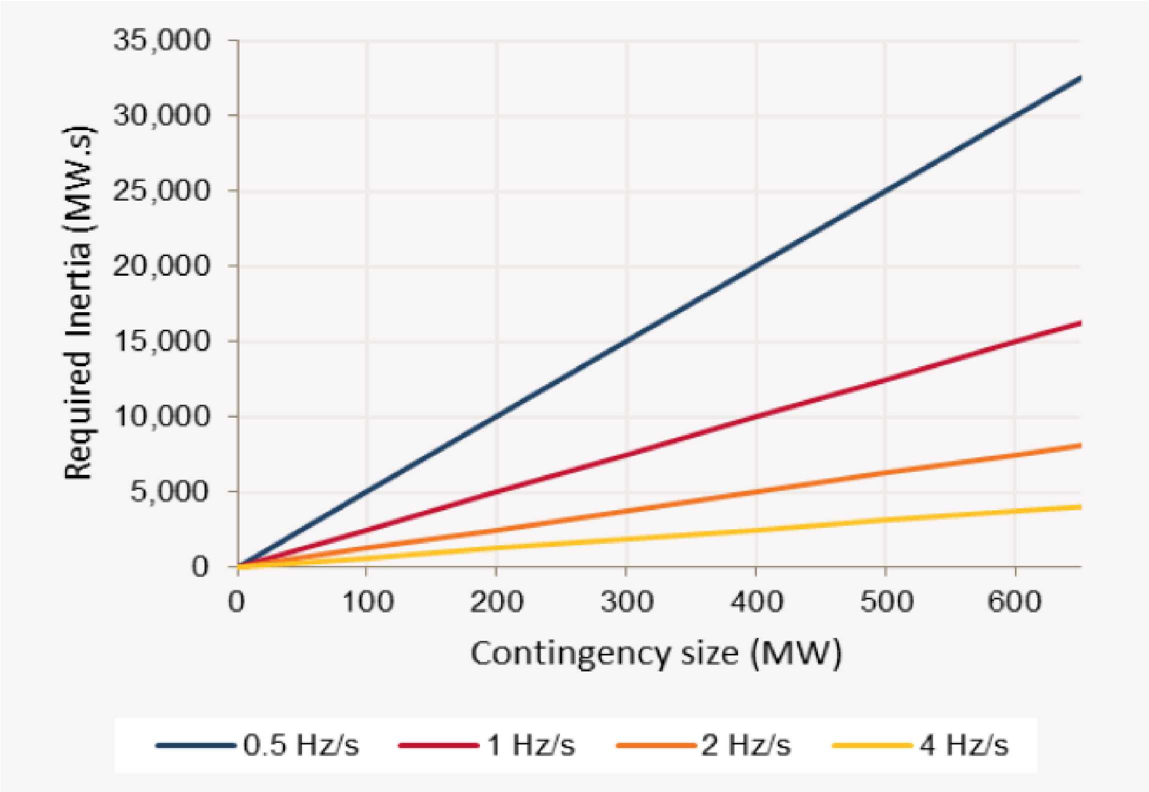
**Question 3**
Do you consider there to be a role for maintaining system strength? Who should be responsible for undertaking this role or how should the responsibility be determined?

Maintaining system strength is a fundamental part of keeping the power system safe and secure at all times or restoring the power system to a secure state after a contingency event. Hence, it is reasonable to consider that mitigating the effects of a weak system aligns with the National Electricity Objective in terms of the safety and security of the national electricity system.

Similar to maintaining bus voltages and power factors at a connection point, connecting parties should be collectively responsible for fault levels on a continuous basis as the generation pattern changes. It is expected that AEMO in its monitoring and operating role of the entire network would have the responsibility of determining minimum fault levels at any point on the network, depending on network simulation studies. In such case, market based solutions or off- market procured services would be the most obvious options for AEMO to manage low power system fault levels. While solutions using the central dispatch process in the form of constraints can be deployed, they may not always provide the sufficient incentives for synchronous generators to remain online. In this case, network support agreements could be used to provide the necessary incentives to ensure minimum fault levels are maintained. This is similar to the example of some hydro generators in the NEM having ancillary service contracts with AEMO to run in synchronous condenser mode for reactive power support services.

**APPENDIX**

**Figure 1:** **Instantaneous RoCoF versus contingency size and power system inertia level**




$$\text{RoCoF} = \frac{50\text{Hz}}{2} \times \frac{\text{Contingency size (MW)}}{\text{System inertia (MW.s)}}$$

*Source: Integrating Renewable Energy - Wind Integration Studies Report (p.7-77), AEMO, September 2013*