Government of South Australia
Department of the Premier and Cabinet

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Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

System Security Market Frameworks Review – Directions Paper

Dear Mr Pierce

The Energy and Technical Regulation Division of the Department of the Premier and Cabinet, South Australia (Division) welcomes the Directions Paper on the System Security Market Frameworks Review (Review) to offer direction on the most suitable regulatory framework to meet current power system challenges in the National Electricity Market.

The Division notes the two-stage approach that the Australian Energy Market Commission (AEMC) is taking in the Directions Paper to deal with the immediate issues for management of power system security in the short term, as well as to optimise the framework to address such issues in the medium to long term. However, the Division is still concerned about the risk of a drawn-out lead time for implementation, as some changes to the National Electricity Rules are still required for implementation of the proposed immediate package. It is also unclear in the immediate package how the Transmission Service Provider (TNSP) procurement framework would be dynamically coordinated with the changing system conditions managed by the Australian Energy Market Operator (AEMO).

Please find attached a submission on the Directions Paper, where the Division is providing feedback to contribute to the discussion on developing pathways to implementation of the necessary regulatory and market frameworks to meet current power system challenges. Apart from general topics in the Review, the submission focusses on how the Directions Paper addresses the requests raised in the related components of the package of rule changes proposed by the South Australian Government in July 2016.

Should you wish to discuss any of the content of the submission, please feel free to call Ms Rebecca Knights, Director - Energy and Technical Regulation Division, on (08) 8226 5500.

Yours sincerely

Vince Duffy
EXECUTIVE DIRECTOR
18 April 2017

System Security Market Frameworks Review

Submission to Directions Paper

Energy and Technical Regulation Division
Department of the Premier and Cabinet, South Australia

April 2017

EPR0053 – System Security Market Frameworks Review

The Energy and Technical Regulation Division of the Premier and Cabinet, South Australia (Division) generally supports the key considerations, procurement mechanisms and proposed approaches outlined in the Directions Paper (Paper) for the System Security Market Frameworks Review (Review).

Key considerations

In chapter 2 of the Paper, an absolute minimum level of inertia is defined to maintain a secure operation of the system. It is understood that this minimum level of inertia would require constraining the region affected to the extent of reducing interconnector flow to a minimum or zero MW prior to separation. It is expected however that this level would allow for the maximum contingency (typically the loss of the largest generating unit or load or loss of high voltage transmission lines) taking into account the maximum Rate of Change of Frequency (RoCoF) the system will tolerate so that the frequency returns to or stays within the frequency operating standard (FOS), with a possibility for the need of load shedding.

Section 4.2.1 in the Paper defines a higher 'required' operating level of inertia that would be prescribed at all times to cover a large percentage of scenarios – for example 90-95%. It is stated in page 14 of the paper that this prescribed approach "would set a level that is sufficient for most generating units and transmission lines to be able to operate at some defined level of their capacity and for the region in which the inertia is procured to operate securely as an island from the rest of the NEM." It is also stated (first paragraph of page 46) that AEMO would model a range of scenarios for which each scenario will require a level of inertia depending on the size of potential contingency and the tolerance of the system to RoCoF. Assuming that all credible scenarios are assessed, it could be implied that a prescribed level would not involve any load shedding for any scenario should it eventuate.

However, it is stated (also in page 46) that a number of scenarios related to protected events would also be modelled by AEMO. This presents a further complication on setting a required level of inertia should AEMO take some ex-ante actions, through the use of Frequency Control Ancillary Services (FCAS) or constraining generation dispatch, or the EFCS scheme associated with that event triggering ex-post load or generation shedding.[1] In this case, it is essential to have a clear relationship between modelled scenarios stated in this Paper and non-credible but plausible events (protected events) when prescribing the required level of inertia.

It is acknowledged that specifications for FFR services (discussed under section 2.2.3) are largely influenced by technologies available today. However, they should be generic enough to capture any existing or future type of technology. As noted in the Directions Paper, the use of FFR services would need to be coordinated with the use of other slower response technologies to manage the control of frequency. Although inertia and FFR are distinct services, FFR may also substitute for some inertia to a certain extent to slow down frequency deviations following system disturbances.

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[1] See Final Rule determination for EFCS at http://www.aemc.gov.au/getattachment/5dad7625-02cd-4b3b-b52d-b70d1b2609ea/Final-Rule-Determination,-Emergency-Frequency-Cont.aspx, page 65

Procurement mechanisms

The Division considers that the four mechanisms outlined in the Paper are conceivable options for procuring inertia and FFR under the National Electricity Rules (NER).

In the case of the mechanism of generator obligation to provide inertia (Box 3.2 in page 24 of the Paper), two approaches are discussed to achieve the provision of inertia from generators either "proportional to their output at any given point in time or, alternatively, as a fixed amount on a continuous basis irrespective of whether or not they are online". With regards to the first approach, this option would defy the concept that inertia being not directly coupled with the instantaneous output of the synchronous machine but rather a function of the mass, diameter and speed at which it rotates or MVA rating of the machine. The second option could probably over-subscribe a level of inertia that the system does not need at times.

The Division would recommend, if an inertia level for each generator is to be prescribed as an obligation, that the level of inertia should be proportional to the MVA rating of the generator. As for any traditional synchronous generator, condenser or motor load, inertia is inherently a defined quantity (expressed in MW.second) that is only incrementally added on a discrete basis to the system when the synchronous machine is connected to the grid. Importantly, the system operator needs to have systems in place to dispatch these quantities of inertia in real time to meet the appropriate level of system inertia, particularly if this process is separate from incremental energy production.

The Division agrees that obligations for non-synchronous generation to provide FFR could be onerous because of the characteristics specific to the technology and the curtailment of energy production required to provide the service. However, an obligation to provide the capability and to register to offer FFR is welcomed as a long term improvement to the management of system security. As a general policy, frequency control should be widened to all types of generation sources injecting power into the grid. To gain the full benefit of such policy, the service should not be confined to just FFR but any type of raise or lower FCAS that the technology is capable of contributing. For example, adding the capability of control systems of HVDC links to respond to frequency deviations is a viable proposition, where speed of response is relatively fast, provided of course that there is spare capacity from the exporting region.

If FFR is to be offered in the market in the proposed subsequent package, it would be more forward-looking to allow any technology to compete to provide FFR and not just non-synchronous generation. Widening the pool of providers is based on the premise that control systems, which are available to offer frequency control services, is or can be made capable of providing FFR regardless of the generation technology. This is demonstrated by synchronous generators having modified governor control systems that would boost power injection into the grid (open-loop response) when frequency falls below a certain threshold or any other trigger (an example already operating in other jurisdictions and some of Tasmania's hydro generators).[2] Allowing all technologies to provide FFR would ensure that all possible resources for arresting frequency fall are captured. It is therefore

[2] See Hydro Tasmania's submission to AEMC's System Security Market Frameworks Review's consultation paper dated 13 October 2016, page 7 of attachment (section 4.3), where a governor boost function is triggered only on high RoCoF.

equally important that the concept of load aggregation to provide FFR in the form of demand response is also brought into the equation when dealing with under-frequency events experiencing high RoCoF.

ERC0214 – Managing Power System Frequency

The following comments are related to Rule change requests made by the South Australian Government to the AEMC in July 2016. These rule changes are covered by the SSMF review.

<u>Rules for a Non-Market Ancillary Service to provide system security services (RoCoF, Low Fault Levels)</u>

The paper presents two options for a TNSP to provide the required level of inertia, whether by directly investing and constructing assets or drawing up contracts with third-party providers for the service.

If the TNSP is not constructing physical assets to provide inertia, it would need to rely on the provision in the NER for a non-market ancillary service (clause 3.11.1(c))

It does not seem that the network support and control ancillary service (NSCAS) framework is sufficient to cover the provision of inertia. Even though a TNSP can use NSCAS as a non-market network support agreement, NSCAS by definition is limited in the means to manage frequency.[3] For example, a synchronous condenser does not control active power into or out of a transmission network to contribute to system inertia, albeit it can inject or absorb reactive power.

In the case of non-market ancillary service (NMAS)[4] other than NSCAS or SRAS, it is unclear if system security services can be procured, as indicated in the original rule change request.

The AEMC should consider if rules need to be changed for TNSPs to be able provide a prescribed operating level of inertia. It would be preferable to amend the NSCAS or NMAS definitions (or develop new rules) to include services other than active or reactive power control to assist in managing system security indicators, such as high RoCoF and low fault levels.

<u>Rules to include guidelines for acquisition of system security services (similar to SRAS)</u>

In section 4.2.1, a required operating level of inertia is determined by AEMO for each region and NEM-wide. On the other hand, section 4.2.1 states that "specific requirements in relation to the content and development of the prescribed process would be set out in the NER and would include the set of system conditions which the required operating level must meet." As the required operating level of inertia is likely to change with the size of contingency at the time, the AEMC needs to consider what level of flexibility is appropriate for AEMO under this process.

In the immediate package, it is understood that TNSPs are required to provide and maintain a defined level of inertia at all times. However, if the required level of inertia has already been met by

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[3] NSCAS is defined in chapter 10 of the NER as "a service with the capability to control the active power or reactive power flow into or out of a transmission network to address an NSCAS need"

[4] NMAS is defined in chapter 10 of the NER as either NSCAS acquired by TNSPs to meet service requirements of schedule 5.1, or in applicable regulatory instruments, or SRAS and NSCAS acquired by AEMO under ancillary service agreements.

the market dispatch process, will the inertia provided by the TNSP be considered as a market benefit? On the other hand, what level of inertia will AEMO have to dispatch whenever the required inertia level is not met? It is unclear how this process is going to run if the most efficient level of inertia is to be procured. The same applies for the contracted FFR service. An efficient procurement of inertia and FFR would need a dynamically coordinated scheme that takes account of the characteristics of online generation and load. In other words, the provision of synchronous inertia and the arming of FFR services will need to be dispatched in coordination with system conditions managed by AEMO.

If AEMO determines the required operating level of inertia for a region using a strictly prescribed process defined in the NER, it is envisaged that in this process the TNSP will be consulted, or will have full freedom, to determine the location of where the inertia is to be supplied for the purpose of contribution to system strength at certain points in the network. This condition is needed so that the synergy between inertia and system strength is maximised.

In response to the discussion of managing a secure system with the required level of inertia , it is questionable, as given as an example in the Paper (page 46), that the limit of RoCoF should be determined by the generator with the lowest withstand capability, which when tripped will impose a need for more inertia from other generators. The level of contribution of such generator to overall frequency control in the region should be taken into account if an optimum or sub-optimal solution is to be achieved. If the inertia (synthetic or natural) it provides is small or zero, that generator should not subsequently determine the amount of system inertia required. In general terms, this is a valid reason to oblige generators to withstand a maximum standard RoCoF in connection standards so that the behaviour of all generators is known beforehand.

It may be possible to deduce a maximum RoCoF based on the tolerance of the system expressed in the form of Automatic Access Standards (AAS) and Minimum Access Standards for generators. However, due to the uncertainty of the behaviour of pre-2007 generators under high RoCoF conditions and also the likely dysfunction of under-frequency load shedding schemes under such conditions, it would be prudent to subtract a margin from the generator tolerance limits when setting a RoCoF standard (see discussion later on RoCoF standard).

For example, in its Project Specification Consultation Report (PSCR) supplementary information paper,[5] ElectraNet presented scenarios for the required level of inertia for a fixed RoCoF profile (currently set at the current regulated 3 Hz/sec for South Australia) based on the AAS of generators (withstanding 4 Hz/sec for 250 ms), by altering the two factors of amount and speed of response of available FFR. This is a more realistic example of calculating the required level of inertia.

In the long run, the Paper mentions that in the subsequent package an incentive framework will be developed to procure additional inertia.

For either the immediate or subsequent package framework, it is deduced that obtaining inertia from generation sources under contract would be problematic (as expressed in page 51 of the Paper). Otherwise, any generation as a by-product of inertia would interfere with the energy

[5] See https://www.electranet.com.au/wp-content/uploads/resource/2017/02/SAET-Supplementary-Information-Paper-Final-13-Feb-2017.pdf, page 13.

market, as expressed in the submissions by Engie and the SA Government on the Interim Report. The Division considers that if this issue is still not resolved, the most likely and straightforward solution is to limit inertia provision to non-generating sources in the interim so that inertia provided by the energy market is not displaced until an efficient integration mechanism with the market can be reached.

Rules to allow Reliability Panel to develop a standard for RoCoF

It is stated in the Paper (page 11) that the level of system inertia determines the size of the initial RoCoF upon the occurrence of a contingency of a given size. The initial RoCoF is one of the three factors that influence the ability to maintain control of the power system frequency following a contingency.[6] Analytically, setting an upper (and sometimes lower limits) for each factor should determine the standards to be adhered to. Achieving compliance with an initial RoCoF standard is by the means of the two levers of altering system inertia and constraining contingency size. The provision of FFR (which is assumed to have a time delay) should reduce the amount of inertia and contingency constraint required so that the RoCoF limits are not breached throughout the contingency event. Hence, putting an upper limit on RoCoF will ensure generators remain online, adequate time for FCAS to respond and emergency frequency control to operate effectively. There is little sense to operate the system at any time when RoCoF is too high knowing for a fact that assets connected to the grid will not be able to stay online or contingency measures to have adequate time to operate effectively.

There is an argument that a RoCoF standard is not required as AEMO already manages the system to stay within, or return to, the limits of the Frequency Operating Standards (FOS) based on an estimate on RoCoF at any time. However, it is precisely the level of RoCoF that determines the deployment of measures to maintain the frequency with the FOS. Being over conservative and limiting RoCoF to low levels may result in over procurement of resources. On the other hand, allowing RoCoF to rise to very high levels might cause cascaded failure. Hence, a RoCoF standard will give the market certainty over the most efficient level of services to be procured to ensure system security.

An example of how to quantify the required level of inertia when altering the RoCoF target is provided by Electranet in its South Australian Energy Transformation project.[7] It is demonstrated in ElectraNet's studies that for a fixed amount and response time of FFR, the required inertia can double between a high RoCoF target (minimum system target) of 3 Hz/sec and a lower RoCoF target (preferred system target) of 1 Hz/sec. It is to be noted here that the difference between a minimum system target and a preferred system target is the ability to increase interconnector transfer as well as operating an islanded system in a secure manner indefinitely (as compared to a satisfactory manner for a limited period of time after a contingency).

Other jurisdictions have implemented a limit for RoCoF, largely on the basis of the level below which generators are able to withstand. For example, Great Britain has found that the loss of its interconnector importing at the 1000MW limit (largest contingency) would cause RoCoF to exceed

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[6] Other factors are capacity to return system to stability and generators withstand capability. See discussion in Interim Report, at http://www.aemc.gov.au/getattachment/d268221e-a8f6-4972-aee2-dd3a6e8ef85c/System-Security-Market-Frameworks-Review-Interim-R.aspx, page 23 - 33

[7] See https://www.electranet.com.au/wp-content/uploads/resource/2017/02/SAET-Supplementary-Information-Paper-Final-13-Feb-2017.pdf, page 15-16.

the 0.5 Hz/sec operational limit by 2025-2030.[8] Although limiting flows on the interconnector can be a mitigation measure, this solution is increasingly costly given the increasing periods of RoCoF limit violation. It was concluded that increased frequency reserves are required around the 1 second and 2-10 seconds timeframes. In 2014, Great Britain imposed higher RoCoF standards on existing and new generators above 5MW capacity (synchronous and non-synchronous) up to 1 Hz/sec.

In the case of the NEM, the Reliability Panel can define in broader terms what level of RoCoF (and the method of its calculation) across the NEM the system can withstand when all interconnections are in place. This level will most likely be much higher than regional limits that need to be defined based on the capability of assets where the region operates as an island. Given that high RoCoF is most likely to occur after non-credible events, it is understood that a level of RoCoF will have to be inherently defined for management of mitigating the consequences of non-credible but plausible events (known as protected events in rule change ERC0212) to arrive to the most feasible post contingency state. A level of target RoCoF in this process that is transparent gives AEMO guidance on what contingency measures should be designed to meet the RoCoF standard and provides market participants the clarity on how the protection systems of their assets would respond within the RoCoF operating range. This limit can be changed from time to time as the characteristics of generation and protection technologies change (as mentioned in page 57 of the Paper).

ERC0211 – Managing Power System Fault Levels

The following comments are related to Rule change requests made by the South Australian Government to the AEMC in July 2016. These rule changes are covered by the SSMF review.

Rules to include standards for low fault levels

The Division supports the proposed rules outlined in the Paper with regards to accommodating issues with fault levels:

- For existing generators, introduction of a new Rule to oblige existing generators and NSPs, in consultation with AEMO, to determine a minimum allowable short circuit ratio at each generating connection point. However, it needs to be clear in the Rules what measures are available for the existing generator to exercise during circumstances when system strength is at its minimum. For example, a range of solutions would depend on either reducing generator output to maintain the minimum agreed SCR level (registered with AEMO) or deploying extra equipment to boost system strength at the connection point, either by the generator or the NSP, at the expense of the generator.
- For new generators, amendment of the existing Rule[9] to include a provision for a minimum fault level at a grid connection point, in addition to the existing maximum fault level clause, as part of the information provided by the NSP to a generation connection applicant. However, it is necessary to place the above obligations in the Rules on respective parties rather than leaving them as conditional on request. For example, Rule S5.2.4(e1) should be amended so that all

[8] See DGA consulting report International Review of Frequency Control Adaptation, presented to AEMO in October 2016, at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/FPSS---International-Review-of-Frequency-Control.pdf, pages 39/-44 .
[9] NER clause S5.2.4(e1)

technical information provided by a NSP must be advised to a new connection applicant rather than just when requested.

- Consideration of imposing an obligation on new inverter-based generators to operate under low short circuit ratios in order to reduce the need to increase system strength by investing in extra services. It is expected that the provision of any new Rule requiring generators to operate under conditions of lower system strength should carefully consider the impact on the ability of the protection systems of transmission and distribution networks to operate correctly, as well as the ability to manage network voltage levels within technical limits and standards.

Rules to allocate responsibility for setting fault levels at network locations

The Division supports the proposed rules outlined in the Paper with regards to clarifying responsibilities for maintaining system fault levels:

- A new Rule to oblige *NSPs* to maintain a minimum system strength at which the generators can meet their registered performance standards, including the minimum SCR. It is noted that new generators, which will potentially degrade system strength for existing generations at a connection point, once connected, will be obliged to meet their minimum SCR.
- An obligation in the performance standards on all *generators* at a connection point to constantly maintain their minimum SCR so that the NSP can ensure a minimum fault level at the connection point.
- An amendment to the existing Rule[10] to place an obligation on *AEMO* to manage system strength in real time, by monitoring locations where minimum SCRs are being breached. It is understood that under these situations, AEMO will take the necessary steps to mitigate the risk to system security when an SCR falls below the registered performance standard, by either constraining the output of the generator, advising the NSP of the low system strength for the NSP to take corrective action or directing either the NSP or the generator to take action to increase system strength at the connection point.

[10] NER clause 4.6.1