Government of South Australia
Department of the Premier and Cabinet

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Reliability Panel
C/o Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235
Attention: Mr Neville Henderson

Review of the Frequency Operating Standard – Issues Paper

Dear Mr Henderson

The Energy and Technical Regulation Division of the Department of the Premier and Cabinet, South Australia (Division) welcomes the timely Review of the Frequency Operating Standard (FOS). The Division takes this opportunity to provide feedback on the Issues Paper (Paper) of the FOS Review.

Since the last review of the FOS, there has been a considerable transition not just in the capability of the current generation stock connected to the electricity grid, but also the type of events that may occur, such as the recently introduced 'protected' event category. South Australia in particular is experiencing a steady change in generation mix, grid-connected and behind-the-meter, requiring a more innovative approach to the management of power system frequency. The characteristics of the increasing levels of non-synchronous intermittent generation are presenting both challenges and opportunities, especially with respect to the power system's sensitivity to operating frequency levels and its rate of change.

The Division agrees in general with the two-staged approach that the Reliability Panel is taking to address the immediate and long-term issues. The first stage of the review is essential, mainly to provide clarity on the regulatory framework stemming from the recent rule changes for the emergency frequency control schemes. The Division acknowledges the complexity of progressing with the second stage of considering the various components of the FOS in light of the current market and regulatory developments.

The Division, however, cautions that too much focus on synchronous generators providing solutions is counter-productive if the number of such generators is declining and becoming less available in the National Electricity Market. Making adjustments to the FOS on this basis would be impractical in some regions, such as the case in South Australia. The settings of the FOS should take into consideration a frequency that is changing at much higher rates. In such a dynamic environment, it may be prudent to consider the settings of the FOS to not just reflect the capability of the equipment connected to the power system, but also the fitness of the traditional monitoring and control tools used in frequency control schemes to meet the FOS.

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Please find attached the submission document providing feedback on the key points raised in the Paper to assist with shaping the approach to the Review. The feedback attempts to answer some of the questions posed within the Paper.

Should you wish to discuss any of the content of the submission, please feel free to call Mr Andrew Manson, A/Director - Energy and Technical Regulation Division, on (08) 8226 5500.

Yours sincerely

Vince Duffy
EXECUTIVE DIRECTOR
17 August 2017

Review of the Frequency Operating Standard

Submission to the Issues Paper

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

August 2017

REL0065 – REVIEW OF THE FREQUENCY OPERATING STANDARD

The Energy and Technical Regulation Division of the Department of the Premier and Cabinet, South Australia (Division) considers that a review of the Frequency Operating Standards (FOS) is highly warranted, considering that the latest reviews were conducted for the mainland of the National Electricity Market (NEM) and Tasmania, in 2001 and 2008 respectively.[1] Since then, the nature of assets comprising electric power systems has diversified considerably, with integrated advanced technologies being used in operating the power system. Changes in power system resources present both challenges and opportunities for the regulatory, market and operational frameworks to define the most efficient range of allowable system frequencies within normal operation and also following contingencies.

The Division considers that the review should consider investigating the appropriateness and fitness of all the elements of the FOS[2] and whether some elements need to be redefined, eliminated or new ones introduced. It is acknowledged that it may not be possible to simultaneously conduct these investigations while work is progressing on the regulatory and operational levels to investigate technical and market-impact issues related to frequency control systems. Hence, the Division agrees with the staged approach that the Reliability Panel is taking to conduct the review of the FOS.

With regards to assessing frequency performance, the changes in power system conditions must be considered in conjunction with regulatory changes over the time span of the assessment of performance. For example, in page 23 of the Issues Paper a comparison is made between the frequency distribution profiles of two days that are 15 years apart. From this comparison a view can be made that the frequency performance of the power system has declined, with consideration of the caveat that one of the days falls on a weekday and the other on the weekend. However, the Issues Paper fails to mention that there were major changes in obligations to meet the FOS between 2001 and 2016 which would definitely shape the behaviour of grid-connected assets and consequently alter the frequency distribution profile. Put simply, the market is responding to new requirements in the most feasible way the market participants see fit.

A more comprehensive approach to study performance is to compare frequency performance over a long period during which it is confirmed that regulatory and market conditions did not change. Following this approach, the increasing trend in instances when frequency fell outside the Normal Operating Frequency Band (NOFB) from January 2016 onwards in the Mainland is a matter of concern.[3] Although the frequency remained within the NOFB for 99% of the time in any 30 day period, there is an upward trend emerging, which may lead to breaching of the current FOS. The Division is looking forward to the findings of the Ancillary Services Technical Advisory Group, as part of the relevant work pursued by the Australian Energy Market Operator (AEMO) within its Future Power System Security program, to explain the causes and the likely future persistence of this trend.

[1] The scope of the FOS review (Mainland NEM) in 2009 is not mentioned here as it was limited in scope to periods of supply scarcity following the bush fires in Victoria on 16 January 2007.
[2] Elements of the FOS are defined as the boundaries of the various frequency bands, the timeframes for restoration of power system frequency following specific classes of contingency events and the accumulated time error.
[3] See AEMO, *Frequency Monitoring – Three Year Historical Trends*, 23 December 2016, p. 4, available at

An exercise of caution is recommended in comparing the FOS with similar standards adopted by other jurisdictions overseas. Power systems around the world vary in configurations and supply and demand mix. Different standards will be needed for heavily-meshed systems with many interconnections to neighbouring power systems, as compared to 'stringy' systems with long-distance interconnections between regions. The same is true for systems that have highly dispatchable synchronous generation and predictable load compared to systems with high penetration of intermittent non-synchronous generation and less predictable load due to uncontrollable embedded behind-the-meter generation (also known as Distributed Energy Resources). Hence, an all-inclusive comparison will require consideration of many aspects.

If frequency standards are compared across jurisdictions on an equal basis, it is also important to have an adequate amount of data of frequency performance (as an outcome of how well the market is meeting the standards) for systems being compared and the context of assessment of performance for each jurisdiction. For example, the tolerance of frequency staying within the NOFB for 1% of the time over a 30 day period may be highly valued in some jurisdictions more than others, depending on the cost put on reliability.

<u>Approach and Assessment Criteria</u>

The Division agrees that the trade-off between the benefits accrued from tighter standards against the costs of delivering those standards should be central to all assessments for any changes to the FOS. Guided by the National Electricity Objective (NEO), any costs imposed on market participants for higher quality will be borne ultimately by consumers and should be offset by tangible benefits translated into added value in terms of price, quality and security of electricity services.

When considering costs and benefits, it is important to take a holistic approach in the assessment, both within the operation of the entire electricity sector and other peripheral markets or regulated services affected by the supply of electricity services. In the latter case, the assessment of dependent markets should be based on economic (and often hidden) costs and benefits, if they amount to be material to the overall economy.

For example, mixed signals can be deduced from the high level analysis presented in pages 27-28 of the benefits and costs of tightening the frequency to be closer to 50 Hz. The incidental cost of the wear and tear on generation equipment from a 'looser' frequency may be negligible compared to the much higher cost of procurement to control frequency within a narrow band. In other words, if the cost of requiring all users (whether as an obligation or a market-based process) to contribute to continuously counter-react frequency deviations from 50 Hz is negligible (because of the spreading of costs on many users), a favourable outcome can actually be a reduction in ancillary service costs for primary frequency control mechanisms that respond on a relatively slower basis. On the other hand, the benefit of having a 'tighter' frequency causing less wear and tear on equipment may actually come at an increased expense for the system operator procuring additional Frequency Control Ancillary Services (FCAS). In effect, depending on the combination of incremental and incidental costs, the perceived outcome of some solutions may be misleading if a particular cost is overestimated at the expense of another and, consequently, the total cost to the consumer is overlooked.

Therefore, all settings in the FOS should be defined under a cost-benefit trade-off framework. As stated in the Paper in page 29, the Division agrees that each component of the FOS needs to be considered in terms of the balance between security benefits and costs.

A more complex task would be to set the criteria in determining and reviewing the settings in the FOS. In terms of determining the settings, there may be an opportunity to eliminate settings, which is discussed in the Paper (pages 14-15) for the element in the FOS of accumulated time error. It may even be reasonable to introduce new elements in the FOS to put more controllability on external factors affecting system security (more on this later in the submission).

With regards to reviewing the current settings, the complexity of two levers is here at play when striking the correct balance of more security benefits at least cost; one is keeping or changing the settings of the elements of the FOS and the other is keeping or changing frequency control mechanisms. Although the former is the subject of the FOS review and the latter is in various stages of development by multiple regulatory and market bodies, the outcomes of both levers are intertwined. Hence, the Division does see the merit of a staged approach, by dealing with the immediate or standalone issues in stage one and deciding on the more complex issues at pace with the frequency control developments currently underway in stage two.

Considering the option of not changing the settings of the FOS standards as the baseline, it may be the case that any solution of changing the FOS settings would not provide any extra benefits regardless of any changes to frequency control mechanisms. Otherwise, it could be proven more feasible that frequency control systems can be adapted to meet the existing FOS at minimum cost. This could be a valid assumption considering that emerging technologies increasingly have the capability of frequency control or centrally managed frequency control schemes can be fitted with newer and better technologies.

On the other hand, the cost-benefit analysis could prove that extra benefits can be accrued from changing the settings in the FOS. One scenario could be the assumption that relaxing the settings could reduce costs by accepting that the design of market mechanisms requires wider deadbands or longer restoration timeframes, as long as system security is not compromised. The second scenario could be that altering frequency control systems would be the best option to accommodate changes in the settings. Examples of both such scenarios have been clearly demonstrated in the Paper.

Apart from the baseline scenario (no changes to the FOS), the Division agrees that it is prudent to ascertain firmness in market frameworks established in the National Electricity Rules (NER) by seeking clarity on the nature of market and regulatory arrangements relevant to frequency control before stage 2 of the FOS review can proceed. It may be the case that a more effective solution can be achieved if the objectives of the different work programs related to the FOS review are coordinated with the aim of the FOS review. If the FOS review has to consider the outcome of frequency control developments at a certain point in time as a given or, alternatively, the frequency control work programs assume fixed settings in the FOS, then either approach may be considered as sub-optimum in terms of finding an efficient solution that makes the best use of all resources simultaneously.

With regards to other programs underway that may have an impact on the FOS review, the Reliability Panel may want to consider the recommendations of the Distribution Market Model review by the Australian Energy Market Commission.[4] Considering the high growth rate of Distributed Energy Resources (DER), the expected dominance of DER on the generation landscape presents some technical impacts on frequency standards, as well as some valuable technical capabilities if their potential is harnessed appropriately.

Considerations for Stage One

Protected Events

The incorporation of the newly defined protected events requires careful consideration of the likelihood and impact of such events, and hence the FOS that should apply for those events. As protected events are classified as non-credible but plausible, they sit in a category somewhere in between credible and non-credible events. The cost-benefit analysis for such relatively rare events will clearly depend on the cost saving of avoiding the consequence of a major disturbance that would have otherwise been dealt with (successfully or unsuccessfully) through the non-credible contingency event emergency control scheme. A protected event control scheme is considered a viable alternative to the indiscriminate under or over frequency automatic load/generation shedding schemes in place, being the back-stop mechanism designed to avoid cascaded failure.

Following the Emergency Frequency Control Schemes recent rule changes, transitional arrangements[5] requiring the frequency to be contained within the extreme frequency excursion tolerance band may provide a practical starting point to consideration of a special FOS for a protected event. Clearly the size of the contingency causing the event as well as the inertia of the system at the time of and immediately after the event are the two main factors determining how far the frequency will drop or rise. In the case of an under-frequency event, the frequency nadir may or may not trigger the under-frequency load shedding (UFLS) scheme, depending on the rate of change of frequency (RoCoF) fall. Triggering the UFLS may or may not be successful to avoid cascaded failure depending on the RoCoF at the time, which signifies the emergency measure taken for any non-credible contingency event where load shedding is activated as a last resort.

Assuming that the range of megawatts lost or gained from a contingency is predictable, it is a matter of discretion of how far the frequency would be allowed to drop before being arrested (then eventually stabilised and recovered under a prescribed maximum timeframe) and this will largely be determined by the cost of the frequency control procured to control the initial RoCoF (by adding more 'synchronous or 'synthetic' inertia or applying system constraints to reduce the potential contingency in the first place). An uncontrolled RoCoF may result in cascaded failure and a system black event.

One option is for AEMO to consider the security benefit and cost trade-off to determine the likely RoCoF on a case-by-case basis, depending on how often the event is likely to happen and what would be the impact. Another option is to have a standard for RoCoF, where a maximum or desired limit is set. A discussion on setting a RoCoF standard as an element of the FOS by the Reliability Panel can be found in the last section of this submission under issues that may be considered for stage two of the FOS review.

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[4] The final report of the Distribution Market Model review is expected to be published on 15 August 2017.
[5] AEMC, *Emergency frequency control schemes, Rule Determination*, 30 March 2017, pp. 74-75.

The Division considers that the South Australian region is the most likely to take account of protected events mainly because of its single synchronous interconnection with the rest of the NEM and the high proportion of clusters of non-synchronous generation in the State. In the absence of any additional security operating requirements,[6] it is clear that the transitional FOS arrangements will not likely be adequate if some protected events are declared in South Australia, as it is questionable that the current UFLS scheme or generation equipment can cope with an uncontrollably high RoCoF following a regional separation form the rest of the NEM during high interconnector flows.

Multiple Contingency Events

Removing the obligation to return the power system to a satisfactory operating state for all events other than credible contingency or protected events means that there is no obligation on the EFCS to operate according to any specifications as a catch-all mechanism for unaccounted for events. As stated in the Issues Paper, a reasonable and prudent system operator may be required to act to prevent the system from collapsing in extreme events. It may be the case that the EFCS is designed to account for a proportion of non-credible events. This proportion of events will depend on the appetite to the level of costs to be borne by the electricity market (and ultimately by the consumers) up to the point that there is little economic benefit to do so.

The introduction of protected events will help in covering some non-credible events. The main reason for defining protected events was for contingency events that are plausible to occur, but not reasonably likely to occur, and most likely have severe consequences. Such events can cause cascaded failure in some regions, such as Tasmania and South Australia, where single points of failure with the interconnection to the core of the power system are expected. Thus, it can be concluded that if protected events are declared largely to cover specific issues in certain regions, there would be little reason to consider a region-specific element of the FOS related to multiple contingency events.

Definition of an electrical island

The Division agrees with the proposed definition by the Reliability Panel in the Issues Paper (page 42) of a viable electrical island. It is reasonable to expect, for a separation event that is accounted for, the power system forming a viable island in a secure operating state, albeit after a short period of a satisfactory operating state. In broad terms, such a state should be able to maintain all the characteristics of a functional AC system until such time it is reconnected to the rest of the NEM.

Definition of a generator event

The Division shares the concerns of the Reliability Panel on the limited applicability of the definition of the generation event in the FOS. The main area that is likely to be critical to this definition is the fleet of non-synchronous generation, having less well-known characteristics as compared to synchronous generators. A sudden loss of generation can occur in the same location or can be

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[6] Examples of current security operating requirement is the Government regulation introduced in October 2016 for limiting flow on the Heywood interconnector so that RoCoF does not exceed 3 Hz/sec on tripping and the direction by AEMO in July 2017 to require a minimum of 3 or 4 synchronous generation (depending on certain conditions) to be running at all times support system strength.

widespread across a region. For example, the sudden drop of power or tripping of a windfarm or a cluster of windfarms in the same area can be a result of a nearby fault. Although all the wind turbines may be able ride through the fault, they may all also experience (for sharing similar characteristics) an active or reactive recovery period where they draw power from the grid coupled with low wind speed at the time of the fault.

Assuming that the pace of adopting new generation technology is fairly consistent in all jurisdictions and that the characteristics of such technologies are fairly similar, the Division agrees that the definition of generation events should be standardised across all jurisdictions. In this regard, a new definition should account for all types of generators and any single points of failure for generation infeed to the grid, similar to the clause of a "transmission element solely providing a connection to a single generating unit" for Tasmania.

Approach to Stage Two of the FOS Review

Apart the discussion earlier in this submission on the approach to changing some elements of the FOS, the Division cautions that too much focus on synchronous generators providing solutions for making adjustments to the FOS is counter-productive if the number of such generators is declining and becoming less available, such as the case in South Australia.

Within a package of rule change requests submitted to the Australian Energy Market Commission (Commission) in July 2016, the South Australian Government addressed the management of high RoCoF so that RoCoF stays below acceptable limits, beyond which power system security may be compromised. This component of the rule change request was proposed to prescribe a process for the Reliability Panel to develop and maintain a system standard for RoCoF in order to guide the procurement of the necessary services and to clarify responsibilities of AEMO, Transmission Network service Providers and market participants.

It is stated in the Issues paper in page 49 that the RoCoF following a disturbance is a factor other than the FOS that may also impact on actually achieving increased power system security. This does not need to be the case if a maximum RoCoF can be defined where it is proven that key generation systems or emergency frequency control schemes will operate correctly and not fail. An element of the FOS placing limits on the RoCoF following contingency events would act as controlling the timeframe for the frequency to reach the containment frequency band, similar to the timeframe to restore frequency to a desired frequency band, albeit on a much faster timescale. Considering the maximum allowable RoCoF alongside the traditional parameters of frequency bands and timeframes to restore frequency following events will be a prudent measure to provide certainty to the market. Hence, putting an upper limit on RoCoF will ensure generators remain online, giving adequate time for FCAS to respond and emergency frequency control schemes to operate effectively.

In the absence of any standard for RoCoF, there will always be a question on what maximum level of RoCoF should be allowed for each credible contingency or protected event. 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.

Given the nature of the current generation mix and the gradual withdrawal of synchronous resources from the power system, the Division urges the Reliability Panel to consider introducing a range of allowable RoCoF limits following contingency events.