PacificHydro

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Con Carellas
Essential Services Commission
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ADELAIDE
SA 5001

Dear Con

Inquiry into the licensing arrangements for generators in South Australia

Pacific Hydro is please to submit the attached document to the inquiry and apologises for the brief delay in this submission.

Yours sincerely

K-P Sum

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Pacific Hydro welcomes the opportunity to submit the following with respect to the proposed licence changes.

This submission will focus on the characteristics necessary to provide, maintain and control a reliable power system. As it seems South Australia is exposed to separation from the NEM more frequently than ever before, it is important that the region maintains the power system control tools necessary to keep the lights on. This requires the restoration of self-sufficiency that has been stripped away through the progression of the market. While it is important to acknowledge that the power system is changing, it is critical that the control of the existing plant be appropriately controlled in conjunction with the new technologies to avoid undesirable failures. The current approach proposed by AEMO does not fully describe how the proposed licence requirements will achieve this outcome, while requiring primary control capability on plant; it fails to address the critical component regarding frequency control.

Despite recent discussions regarding the primary control objective, the advice from AEMO is restricted by the existing market structure and fails to address the serious and obvious primary control problem in SA. The advice is hamstrung by what would appear to be a belief that the current market framework will remain in place. Ultimately the behaviour of generators must be brought back to conform to the obligations in the existing technical standards.

To help dissect the problem a return to fundamental power system control is required.

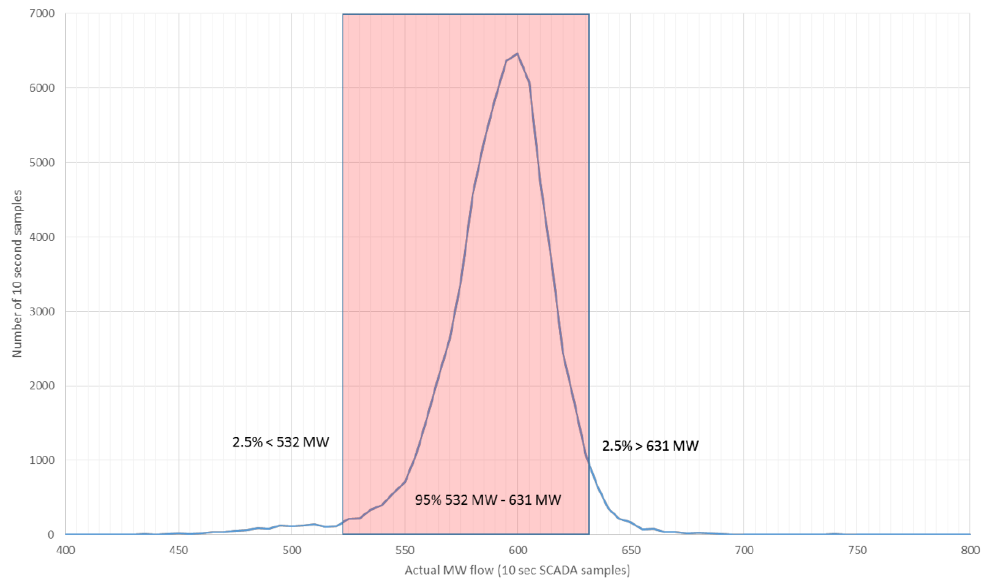
System Stability and Loss of Synchronism

The definition of power system stability is restated from AEMO's Power System Stability Guidelines:
"*Power system* stability is the ability of the electric *power system*, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical or electrical disturbance, with system variables bounded so that practically the entire *power system* remains intact.[i]"

This lays the foundation for how the power system must be operated and gives guidance to those setting transfer limits between regions. Note that the definition above is not subject to whether the disturbance is defined as being "probable" or "credible" it is simply a "disturbance" which means from an engineering point of view the worst case disturbance must be identified and studied.
An examination of the Final System Black Report on page 217 shows that there is a discussion on the results for various interconnector flows between 580MW to 680 MW flows.

Serious control problems are evident when AEMO illustrates the lack of interconnector flow control in the system black report. The analysis in Appendix X of the report shows a "natural" drift of up to 30 MW compared to the target (95% of the time) and greater flow changes for the remaining 5%. The report goes on to say that in order to account for the "natural drift" in actual flows, the modelling was adjusted to test the higher flows – and at the higher values (630 and 680 MW) the studies showed that SA could be separated for a single credible contingency even when the 3 Hz/s RoCoF is binding.

Figure 148 Actual Heywood Interconnector flows with a dispatch target of 600 MW



This information clearly illustrates that the System Stability Guidelines are not being correctly invoked for flows of above 580MW, and if the interconnector flows cannot be adequately controlled then there is a very high risk that limits are being exceeded frequently. The report goes on to state that a credible contingency can cause separation for flows above 580MW, (ie: 630MW and 680MW caused separation). But more concerning than the lack of control is the interpretation of the flows on the interconnector being "natural drift". In electrical systems there is always a reason for a change in MW flow, in this case the "natural drift" or the increased flow in MW must come from units that are providing frequency control, they are increasing their MW output to provide the energy that is being taken from the system. The failure to increase power output within South Australia on the units within South Australia means that load changes are provided over the interconnector. This is not "natural drift" it is control action being taken by units outside of the state.

This raises the question of whether the current operating philosophy for the NEM is adequate to maintain the secure operation of SA.

Having laid out some of these larger issues, with respect to the macro control of the power system, the licence requirements must be pragmatic. The physical response of all the connected plant must be taken into account when setting the system limits. Regardless of the technology type, the recovery or performance of plant has to be taken into account when setting the interregional limits. The licence advice is almost threatening that, due to the "slow recovery" of wind turbines, they could cause loss of synchronism and separation! This is inappropriate as the limits should be calculated taking into account the transient behaviour of all plant connected to the system and limits should never be set so close as to cause separation.

Active Power Response, Inertia OR Frequency Control?

A requirement to provide "fast" active power recovery is asking the wind turbine to extract active power from the energy in the rotating mass. This is the only energy that is available in the 100 ms post fault recovery. It is an inertial response without calling it that. Calling the wind turbine response a slow recovery has to be placed into the context of poor, slow, or no frequency control response from the synchronous units.

There is a clear reluctance to set a technical obligation on synchronous units to meet the current minimum standard for RoCoF (s5.2.5.3), a problem that translates as a cost to the entire region through constraints. The majority of the cost for the inability of gas turbines to ride through 1 Hz/s rates of change is being borne by the renewable sector and SA customers in the form of constraints. The current S5.2.5.3 minimum standard of 1 Hz/s represents a "do no harm" standard. Connecting any generator that cannot operate through higher rate of change is placing the risk and cost of the poor performance on to the rest of the market. The inability of these units to ride through events is compounded by the "loose" governor settings. Correcting the governor settings on a synchronous unit so that it injects energy to its drive shaft early will aid the frequency response and actually help reduce the RoCoF.

Steady State Control
In order to achieve a stable supply of quality electricity, a power system must provide three characteristics: constant voltage, constant frequency and reliability.

In power system control, constant voltage is managed by dynamically controlling the provision of reactive power at both the generator and at various locations throughout a network with reactive devices. The means by which constant frequency is managed is by <u>dynamically controlling</u> the provision of active power to the network.

To state that again – control of reactive power controls voltage, the control of active power controls frequency. This fundamental cannot be altered by the market; it is the physical requirement of the power system.

The fragmented 5 minute market dispatch of active power has no relationship to frequency, so dispatch is often contradictory to frequency, i.e.: send units down when frequency is low and up when frequency is high. This presents a dilemma for the market participant, to follow the dispatch target, in accordance with chapter 3 requirements, or obey the technical standards under chapter 5. The technical standards are clear and requirements for generating units are set out in S5.2.5.11 Automatic standard, which states:

The *automatic access standard* is:

(1) a *generating system's active power* transfer to the *power system* **<u>must not</u>**:

(i) increase in response to a rise in system frequency; or

(ii) decrease in response to a fall in system frequency;

The Minimum access standard states:

(c) The *minimum access standard* is a *generating system* under relatively stable input energy, *active power* transfer to the *power system* **<u>must not</u>**:

(1) increase in response to a rise in system frequency; and

(2) decrease more than 2% per Hz in response to a fall in system frequency.

Dispatch can and does contradict this requirement There is no provision to interpret this technical standard as being "in the absence of a changing target" – the target changes every 5 minutes. Units and regulators must ensure that this technical requirement is obeyed. In law the "MUST NOT" represents a definite requirement so it is difficult to see why the economic dispatch target is taking precedence over the technical requirement.

There is therefore some confusion between requiring "active power control", being managed to fit some sort of adjustable ramp control and the requirement to provide "droop" control for frequency response. Dynamically varying the active power output in accordance with a proportional droop control will provide continuous modulation of active power to contribute to maintaining the frequency. It cannot be divided up into "active power control" in isolation from the frequency control, to do so is illogical. Furthermore, dealing with these topcis in isolation leads to regulators focussing in on one area of control in accordance with rules, which leads to "non-compliance" if the regulator fails to understand how the control action must work for the power system versus a market obligation. This has led to poor control of the power system.

Constant Frequency Control

In contrast to the requirements for reactive power control, the advice on frequency control will not solve the control problem. The advice does not enable the control. The proposed requirement to ensure that new generators have the "capability" to provide FCAS market services, means that units or generating systems have no automatic dynamically variable means of continuous modulation of active power.

"AEMO recommends that all new generators in SA have active power control facilities with the capability to provide the following services:

- Automatic active power response to frequency changes.
- Automatic generation control.
- Controlled rate of change of active power.
- Remote monitoring requirements.

These recommendations would not require the active power control capabilities listed above to be made continuously active, or bid into existing markets for frequency control services, ***but they must be continuously available for service.*** They may be used voluntarily by the generation operator, when directed to do so by AEMO, or when required to do so under other arrangements with the local NSP."

Frequency on the power system is controlled by means of "continuous modulation of active power". The proposed control requirements are flawed and confused in this sense as there is no requirement for an "automatic change over" provision to make active power available for frequency control during a frequency disturbance. An automatic provision of active power to respond to frequency disturbances would be synonymous with the existing reactive power obligation.

The advice stating above that the services would **not** require the services to be continuously active, but must be continuously available is contrary to good engineering control practice.

The required capability may or may not be active depending on whether a) a participant engages in the market and is enabled by that market, or b) AEMO is directing the participant. Neither of these concepts provides the guarantee that the frequency response to a disturbance will be automatic or adequate for the following reason: the market does not know the size of a contingency and may or may not have sufficient service enabled and AEMO rarely knows when an event is about to occur and so is unlikely to be directing a participant prior to an event. (AEMO have made it clear in recent reports that they expect others to inform them of the risk to the power system).

To solve the frequency control conundrum, ALL plant that can, must automatically contribute active power to arrest the change in frequency that occurs during a frequency disturbance. This has to be done during the disturbance and cannot be by means of enablement or direction. It has to be in place all the time and automatically active when required. To do otherwise is to risk market failure/system collapse and human error.

Relying on operator action to "direct" for frequency control services is a flawed control practise and highly unlikely to deliver the services required. Power systems work because automatic control action is taken in sub second timing in response to changes in the power system. Humans cannot detect and act in time to manage events on the power system.

It would be illogical, costly and inefficient to require new generators to be "capable of providing FCAS services" when the existing FCAS services are failing to provide constant frequency control. The primary controls specified must be active to contribute to frequency control, as they should be across the NEM. Conforming to the existing Market Ancillary Services Specification would be costly, inefficient and inadequate when frequency control requires continuous modulation of active power.

Large movements of frequency on the power system are driven by bulk movement in the synchronous fleet. Wind farms and solar farms have a much smaller capability to provide control of such large movement and should not be expected to correct the frequency when the synchronous fleet is hunting or oscillating. Tightening the system frequency will mean that all generators move around less, the contribution from individual generators or generating systems would be smaller. It does mean constant smaller movement but this is preferred to the larger movement given the wandering frequency at the moment.

In AEMO's advice regarding disturbance ride through criteria there is a statement on page 27 section 3.3.1 that says: "These performance requirements have been specified to ensure that **all generating systems** act in a co-ordinated manner to support the network insofar as possible during a contingency event, and ensure that in the period following a contingency event, **all available resources** can be used to stabilise and secure the power system." This statement will not be true if unit “capability” is not enabled. The recent system black event and the provision given to the synchronous units that they can "disable their governors" in accordance with the market dispatch, illustrate a market failure. Frequency control cannot be “dispatched”, regulation services, being from the AGC system, cannot adequately control frequency in isolation. Primary control with appropriate settings on all synchronous units is required, a similar form of control (droop) can be enacted through the park controllers of wind farms and solar farms.

AEMO’s advice is setting control obligations on new technology while failing to address the existing weaknesses in the market. The market is meant to provide a security constrained dispatch of the scheduled generators. This is not true if the governors are disabled / or defeated by unit controllers and units are following their market dispatch target or AGC signal in contradiction to system frequency. And as described earlier, the lack of governor response contributes to the inability to control the interconnector.

Governor response was mandatory prior to the market, and the FCAS market was understood to be an enablement market, that meant the controls were in and active. The payment was to those who were market enabled but it did not mean that only those enabled provided the contingency service because that could be insufficient for unplanned non-credible contingency events. The responsibility of the system operator who is responsible for system security must be to operate the system to withstand not just credible events but also to position the system such that it has the best chance to withstand worst case events. While it is difficult to design for all such events, the robustness of the system controls is extremely important to give the system best chance of survival.

The experimental nature of the FCAS market is now playing out on the South Australian system. The Commission time should consider a requirement on the synchronous units to provide tighter governor response and that it be enabled at all times to provide frequency control. It would contribute to removing the “natural drift” on the interconnector, and help maintain the interconnector within safe operating limits. If the system frequency were tightened up, wind farms and solar farms could enable frequency droop control and there would a minor impact on active power production rather than a major one. In other words the control action required when the frequency is tight would be smaller than that required when the frequency is wildly meandering such as it does now.

Pacific Hydro acknowledges that as an owner of wind farms it has not provided (nor been required to provide) frequency control from the wind turbines that it owns in SA. However, as the frequency response in the power system was still very strong when the wind farm was built it was not possible to foresee the deterioration of system frequency at the time the standards were negotiated for the wind farm. While some controls are possible, it is unlikely to be "continuous modulation" as the turbine type is ill suited for this type of control. Newer turbines, however, can provide suitable continuous controls.

The requirement to have “Automatic generation control” is illogical. If all units implement connection point droop control and the frequency standard is tightened back up the need for regulation (AGC) control is reduced. This should be the aim. Requiring all units (regardless of size) to implement this expensive response which can be contradictory to good frequency control due to time delays will not resolve the actual control problem. It feeds into a narrative that is about “market services” but does not look at the root cause of the issues in SA.

It is an oxymoron to state that the control capability does not have to be continuously active but that they must be continuously available for service. This is market ideology that leaves SA in the situation that is today. To control frequency, active power must be continuously modulated.

Recommendation Frequency Control:
That scheduled generating units must have the capability to control frequency at their terminals by means of appropriate deadband and droop controls and have it active all the time to conform with the first part of the current technical standard. The existing opening statement of the technical standard S5.2.5.11 must take precedence over economic dispatch.

That semi-scheduled generating systems must have the capability to control frequency at their connection points by means of appropriate deadband and droop controls, and have it active to conform to the agreed level of S5.2.5.11 technical standard.

That semi-scheduled generating systems be capable of providing frequency controls that can extract energy from the drive train for a step change on the terminals of the individual generating units. This is acceptable but how it is intended to work must be related to frequency control. A semi scheduled unit should not be penalised after the event as it has to recover its active power after extracting energy from the driveshaft. AEMO’s concern about “procuring” fast frequency response should be set aside; the active power injection is obviously a desirable characteristic and should be physically available to the network.

The control specification requirements from AEMO are acceptable, but the confusion over “active power control” versus frequency control is problematic. These are essentially the same thing and active power control must be related to frequency control not just for market dispatch as the economic dispatch does not conform to frequency control.

Constant Voltage
Examination of the existing licence condition provides an insight as to whether constant voltage will be achieved.

10. Reactive Power Capability

10.1 The electricity generating plant operated by the licensee must at all times be capable 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.

10.2 The electricity generating plant operated by the licensee <u>must at all times be capable</u> of providing:

(a) subject to clause 4(b), at least 50 per cent of the reactive power required to meet the power factor referred to in clause 10.1 <u>on a dynamically variable basis</u>; and

(b) the balance of the reactive power required to meet the power factor referred to in clause 10.1 on a non-dynamic basis.

10.3 At generation levels below full rated output the electricity generating plant operated by the licensee must be capable of:

(a) absorbing reactive power at a level at least pro-rata to that of full output; and

(b) delivering reactive power at a level at least pro-rata to that of full output.

10.4 For the purposes of clause 10.2(a):

(a) <u>dynamically variable means continuous modulation of the reactive power output over its range, with an initial response time or dead time of less than 200 milliseconds and a rise time (as defined in clause S5.2.5.13 of the NER) of less than 1 second following a voltage disturbance on the network;</u> and

(b) for a period of not more than 2 seconds on any single occasion, a short-term overload capability may be used to meet the 50 per cent requirement, provided that use of that short-term overload does not cause a breach of any other licence condition.

10.5 The reactive power capability of the electricity generating plant operated by the licensee must be capable of control by a fast-acting, continuously variable, voltage control system which is able to receive a local and remote voltage set point.

10.6 The electricity generating plant operated by the licensee must be able to operate at either a set reactive power, or a set power factor, which is able to be set locally or remotely at any time.

10.7 The power factor or reactive power control mode of the electricity generating plant operated by the licensee must be capable of:

(a) <u>being overridden by voltage support mode during power system voltage disturbances</u>; and

(b) automatically reverting to power factor or reactive power mode when the disturbance has ceased.

The reactive requirement in the existing licence in clause 10.2 sets a requirement for reactive power amount that "<u>must at all times be capable</u>" "<u>on a dynamically varying basis</u>". To "dynamically vary" an amount of reactive power means that it must be controlled all the time. To think that this is just a "capability" that will be called on from time to time is not logical given the wording in the licence. The provisions describe whether the control is for power factor control or voltage control, but under 10.7(a) it is clear that voltage control must be active during system disturbances.

Clause 10.4 defines delay time, the rise time and settling requirements of the control system for reactive power in response to a disturbance (step change). The requirement to automatically change over to dynamic voltage control during a disturbance and then change back to power factor or reactive control defines the active control mode that <u>must</u> occur during a disturbance.

Similar requirements should be in place to the control of active power for frequency control.

Recommendation

The Commission should consider simplifying the obligation so that generating systems that can, do remain connected in voltage control at all times

System Strength
Not that long ago, NSPs were worried about too much fault current and that connecting parties would have to pay to upgrade the network for the additional fault current that was being contributed. Here we are less than a decade later and suddenly "weak in feed" is being treated as a problem. Some clear obligations need to be set on the NSP's obligation as it would be easy for an NSP to use the connecting party's fault current contribution in a manner that would force additional cost onto the connection. Once upon a time the argument was about "who's ampere?" was the one that caused the need for an upgrade? Now it would appear to be "who's lack of an ampere?" will cause the need for additional cost? Provided that the setting of the minimum fault levels is open and transparent and NSPs must publish the existing fault level (actual) and the maximum and minimum for each location in the network the proposal will be workable. Any lack of transparency will lead to manipulation in commercial negotiations.

Detailed Models
Providing detailed model requirements on future projects is possible. Obtaining detailed models on existing plant is highly problematic and costly. Protection settings are not normally included in dynamic models. This is because the engineer undertaking the studies should be examining where the system is taking the model, in order to know the limits of both the system and the generators. Given that studies are normally undertaken for contingent events – that include a credible fault and an auto reclosure onto a persistent fault, it is unlikely that system studies would have done anything to avoid the system collapse as the abnormal fault event would not have been anticipated or studied.

Limits for the interconnector have not been set using greater than N-1 on prior outage studies. Studies that require using multiple faults must be applied to synchronous units in the same manner that AEMO intend to apply them to wind turbines. This might lead to a truer understanding of the limits of stability.

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[i] Adapted from the IEEE definition, in "Definition and Classification of Power System Stability", IEEE/CIGRE Joint Task Force on Stability Terms and Definitions", 2004 IEEE AEMO Power System Stability Guidelines