PacificHydro

Submission

Independent Review into the Future Security of the National Electricity Market

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1. Introduction

Pacific Hydro welcomes the opportunity to provide a submission to this review. Pacific Hydro develops owns and operates renewable energy power stations in Australia, Chile and Brazil. In the NEM Pacific Hydro owns and operates wind farms and several small hydro plants, along with the Ord Hydro and associated transmission system in Western Australia. Pacific Hydro's participation in the commercial delivery of energy in Australia pre-dates the NEM.

This submission will focus mainly on section 4 consultation questions as there is an immediate and obvious problem with frequency control under the current market framework and it is the single greatest threat to power system security. Pacific Hydro has submitted the attached paper on frequency control which places into context the history of the FCAS market and why there is a significant problem with the control of the synchronous generating units which constitute 94% of the power system.

This threat to the power system calls for an in depth system dynamics control engineering analysis to be undertaken. The recent South Australian black out presents a key question that has not been asked, which is, "why does a region collapse when two separate relatively small generation contingencies (such as 130MW then a further 200 MW) occur?" From a power system control point of view this should not occur and, with appropriate controls, does not occur.

Before the consultation questions are addressed, this submission provides some commentary around the events of 10 February 2017 in NSW.

2. Incident on 10 February 2017

a. Further questions arise from the operation of the power system on both the 8th and 10th of February 2017. In particular, an examination of the 10th February incident illustrates a very poor operating condition.

b. At around 16:25 to 16:30 on the afternoon of the 10th February the two interconnectors (from Vic and QLD) into NSW were being operated beyond their exports limits, to provide power to NSW which had a peak demand, but not a record peak demand. There were heat issues that had developed at Vales Point which the system operator (AEMO) was informed about, and in this period a gas fired turbine at Tarawalla (400MW) tripped off.

c. Following the loss of this unit there was a period of 7 minutes in which there was a slow lightly damped power system oscillation in which the frequency oscillated between 49.85 and 49.75 Hz with a period of 22 – 24 seconds. It is evident that units were hunting and the oscillation did not dampen or recover until the frequency was returned into the normal operating band after a dispatch interval.

d. The oscillation was reflected throughout the NEM including into Tasmania through the Basslink controls. It is unlikely that the real time system dynamics monitoring system in the control rooms of AEMO would identify this peculiar mode.

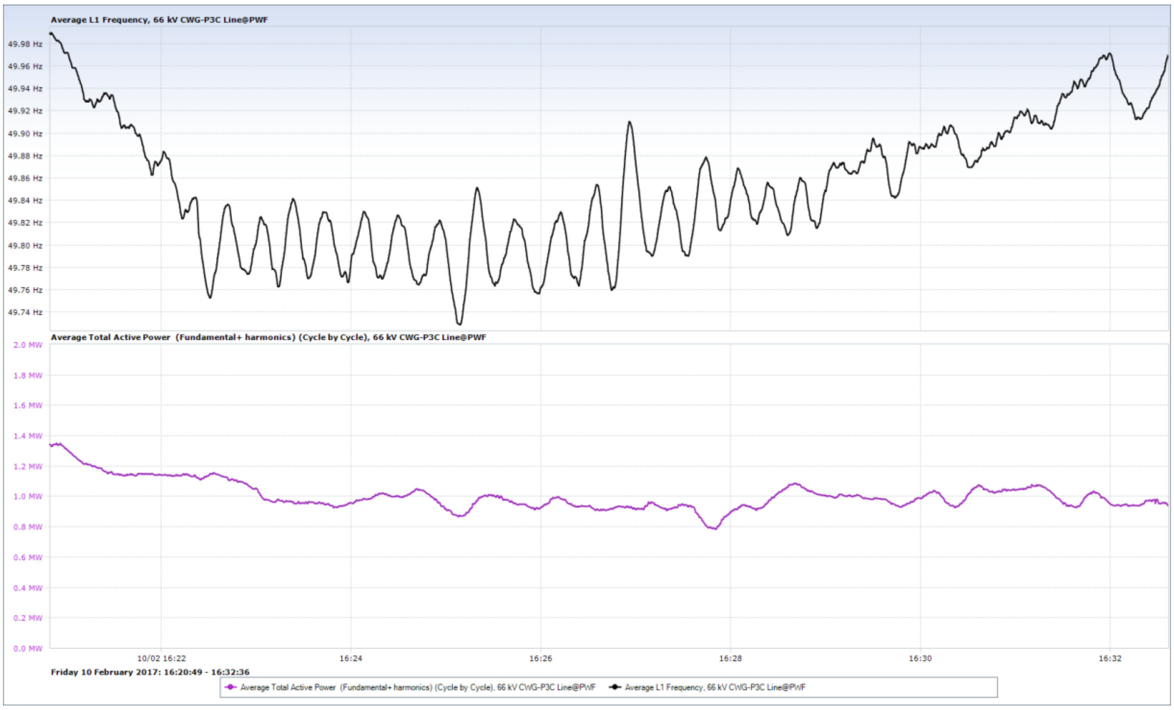
e. During these dispatch intervals there were no contingency raise services enabled within NSW. This is a similar scenario to September 28 2016 in South Australia, albeit with greater interconnection.

f. It is reasonable to think that NSW was a contingency away from collapse, whether that be for voltage collapse, due to lack of internal support and overloading of the interconnectors, or otherwise due to the frequency instability. Studies would need to be undertaken to examine this in detail.

g. Figure 1 below illustrates the system frequency that occurred in this period (in blue) and in purple the response of an "asynchronous" wind turbine to the changes in frequency. Clearly the asynchronous remains stable through this disturbance and does not oscillate with the frequency.

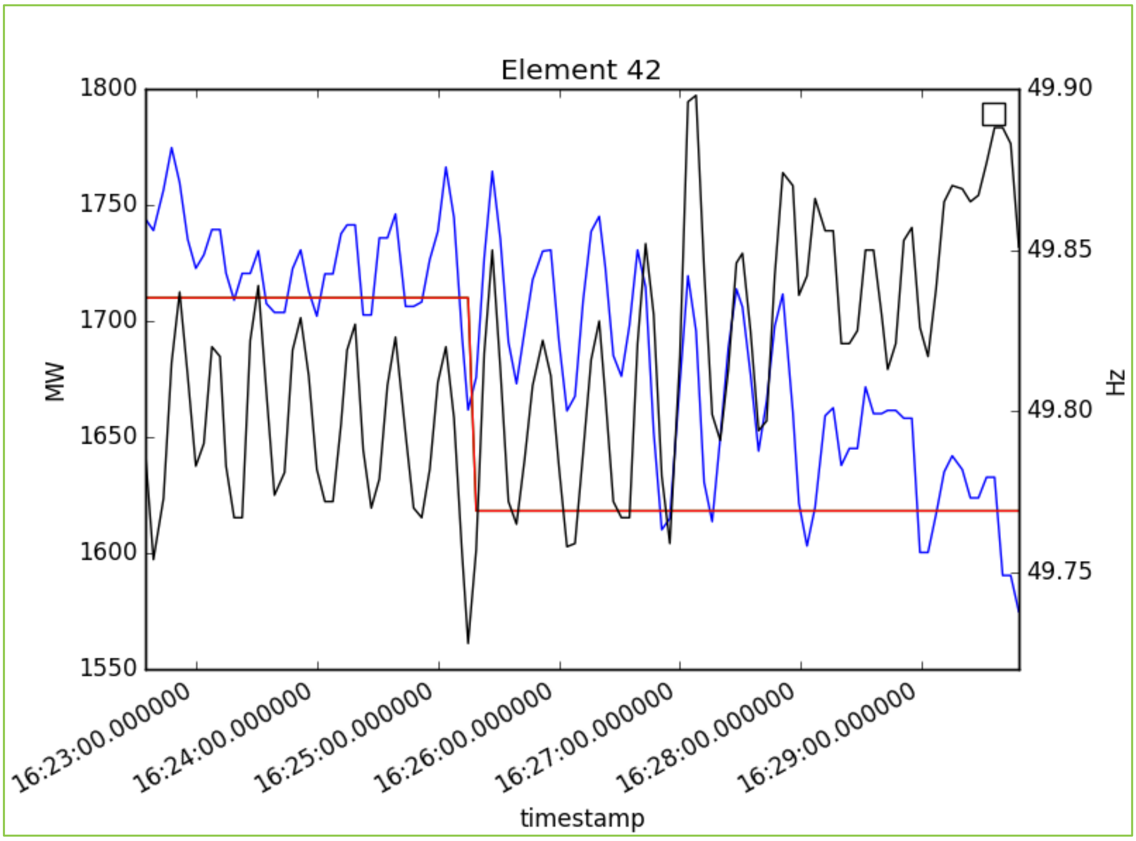
h. Figure 2 is taken from the 4 second data used for the allocation of frequency control costs. This trace shows frequency in black and the MW output of a large synchronous unit. This unit is clearly being "excited" by the mode of oscillation. The unit was not enabled for frequency control but it would appear that the natural frequency of this oscillation is exciting the unit. No frequency control services were enabled in NSW, all control was being provided by units in Queensland, Victoria and SA. A large number of units were actively being excited by this mode, although it is hard to say which units were providing damping and which ones were not due to the data sampling.

Figure 1 Frequency oscillation on 10 Feb 2017



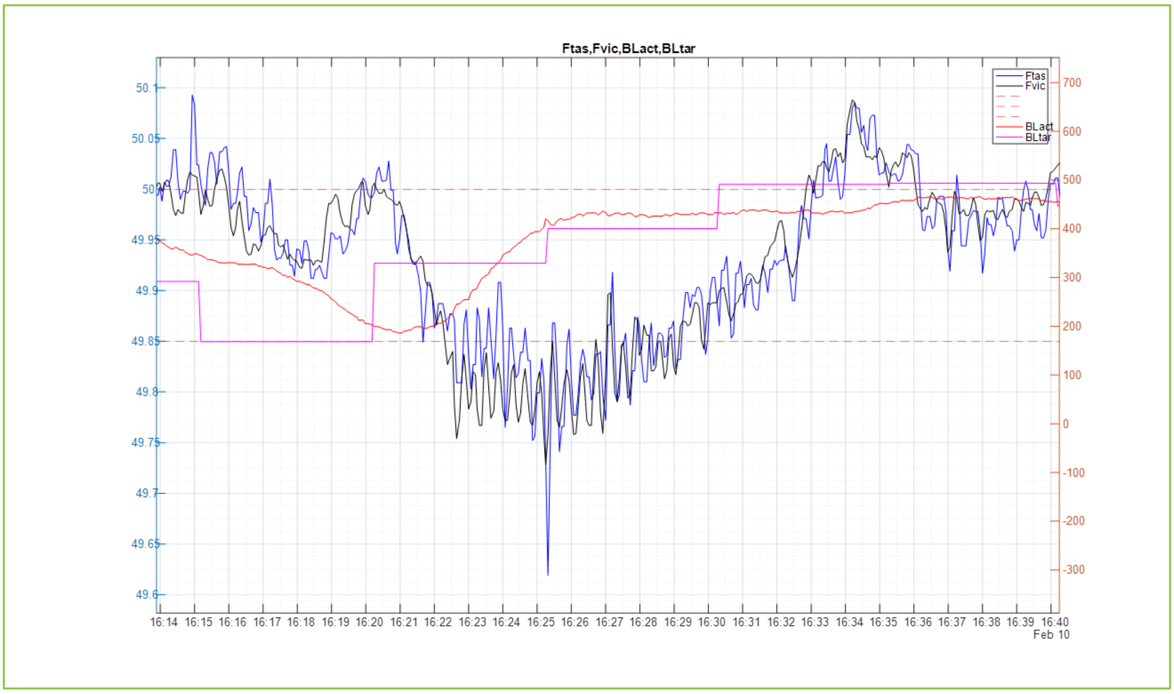
Black –System Frequency,
Purple – Asynchronous unit MW output (variation less than 0.6MW)
Source: High speed data measured at Portland Wind Farm 66kV

Figure 2 Synchronous unit response during frequency oscillation



Black – System Frequency
Blue – Synchronous unit MW output, excited by the mode (variation > 120 MW)
Source: AEMO 4 s data

Figure 3 Tasmanian and Mainland Frequency 10 Feb 17



Black: Mainland frequency
Blue: Tasmanian frequency
Source of Data:Dr M Peikutowski Hydro Tasmania.

i. Due to the controls on the Basslink interconnector, oscillatory behaviour on the mainland is reflected and amplified into Tasmania.

j. It is critical that these issues be examined in depth by engineers with the correct specialised knowledge regarding power system dynamics and control. The deterioration of frequency control illustrated above and within the attached paper provides insights into why the NEM no longer has tight and well dampened frequency control. Delaying the frequency response of the synchronous units on a long power system such as the NEM contributes to reduced damping and the risk of oscillatory behaviour which can damage synchronous units.

k. Australia is one of only a few countries in the world where frequency control is purchased via market mechanisms, and the design of the frequency control market pre-dates the introduction of large scale renewable energy. The attached paper illustrates the history of why we are where we are, and how the frequency control of the power system has deteriorated slowly over the last 15 years, how this deterioration is supported by the Rules and how the Rules have penalised good frequency control.

l. Larger generation contingency events than those experienced on 28 September 2016 have occurred in South Australia. The loss of Northern Power station has caused larger swings against the interconnector, the difference between the events in 2004 and 2005 to 2016 are greater wind power and <u>changed control systems on the synchronous units</u>. The preliminary report into the future security of the National Electricity Market describes on page 26 that synchronous generators have inertia "because of their large rotating mass". This is true, however all rotating mass has inertia. The distinction between a synchronous unit and an asynchronous unit is the direct electrical coupling of the synchronous unit. A sudden step change of load on the terminals of a synchronous unit extracts immediately an inertial contribution, that is the electrical energy is drawn from the kinetic energy in the rotating field of the unit. An asynchronous unit has inertia, but it does not contribute an increase in electrical output unless controlled to do so.

m. The control systems which enable wind turbines to provide an inertial response were developed around 2010 in response to a tender requirement from Hydro Quebec. The technical rules for generator performance standards in the NEM were implemented in March 2007, and there has been no review formal of the technical standards since that time.

n. Not all wind turbines have this control feature and many Australian wind turbines predate this control feature. New wind farm developments are not required to provide it, however, with the costs of frequency control being exorbitant many are investigating implementing the controls where possible.

o. With respect to the inertial contribution of synchronous units, it is illogical to separate an inertial contribution from the requirement to control frequency as the extraction of electrical energy from the rotating field decelerates the unit, and if no additional energy is put into the synchronous unit it slows down and the frequency will continue to fall. In the NEM the removal of primary governor control from actively controlling the energy into the synchronous generating (unless paid under the FCAS market) has resulted in a significant deterioration of the frequency control. Apart from extremely poor frequency control, the FCAS markets are now causing excessive cost on all participants (save those being enabled), it is an inefficient and expensive experiment in market management of frequency and requires a full engineering investigation to reset the performance of the power system.

p. On the 28 September 2016 South Australia was operating without any primary governor control enabled which has been dismissed in the formal analysis as "when a generator is not participating in the FCAS market, the governor may be disabled altogether[1]". This disablement of governors appears to be a recent phenomenon as the contingency services were undertaken as an enablement market only, that is you were paid if you were enabled but the controls were in place all the time.

[1] Page 42 AEMO: Third Preliminary Report "Black System South Australia 28 September 2016"

q. On the 10th February 2017 NSW was operated without any FCAS Raise services enabled within the region. This raises questions as it is unclear which units have governors that provide frequency response regardless of the market enablement.

r. It is important to note that wind turbines are not at risk of damage when oscillatory behaviour occurs on the power system, but the synchronous units are. The oscillatory behaviour would appear to stem from the control settings that have been enacted under the FCAS market.

4.1 What immediate actions could be taken to reduce the emerging risks around grid security and reliability with respect to frequency control, reduced system strength, or distributed energy resources?

Immediate action that is required:

1: Reinstate appropriately designed primary governing control within the normal operating band and develop an incentive for the provision of good frequency control. This can be done quickly on the existing synchronous generation fleet as the capability exists already within their control systems. A significant proportion of units should be incentivised to re-establish good frequency control settings in their governors (and unit controllers) to ensure adequate available frequency response.

Newer technologies can and will provide fast acting frequency control but there is insufficient weight in these technologies currently connected to the power system with the capability. Fast acting frequency control is readily available from thermal units with excess steam within their boilers and has always been relied on to act to arrest the fall in frequency for large contingencies. Power systems depend on being able to control the input power to match the demand which is a function that synchronous machines can easily provide, however, the market has penalised units for this action.

2. Remove the regulatory penalties for good frequency response. The disincentive created by ideal “energy market linear ramp model” does not anticipate the need for primary governor control within the normal operating band. Primary governor control is a far more stable method of controlling the power system than secondary AGC or regulation services. Remove the causer pays regime for the recovery of the regulation services as it is a flawed calculation. It is costing participants and customers millions of dollars for a system that does not measure actual frequency response and is designed in manner such that participants cannot provide a control system to mitigate the risk.

3. Undertake a review of the frequency standards and then decrease the size of the normal operating band. Alter the market framework (or remove it), and reintroduce primary governor response into the normal operating band without penalty. Re-examine the “causer pays” regime, including the charging triggers under that regime and the effect it may be having on good frequency response practices..

4. Undertake an appropriate technical standards review with network, and power and control engineers working through what sort of controls are required. Recent technical reviews have been undertaken without broad engineering input, creating decisions by stakeholders who may or may not be participants in the actual market, and may or may not have engineering knowledge of the power system. Include a full review of the control philosophy of the power system to ensure that the hierarchy of control is reset. This means the primary controls of the generating units (all types of generators) is placed at the forefront of managing the power system – the market is an economic overlay and should not be expected to provide the primary control! The market systems must always take a secondary position behind the power system control, currently this is not the case and the effect is detrimental.

4.2 Should the level of variable renewable electricity generation be curtailed in each region until new measures to ensure grid security are implemented?

No, this is incorrectly allocating blame for the problems in the system operations and market management onto the new technologies. Renewable energy such as wind power does not “de-stabilise” the grid.

Figure1 and Figure 2 set out above illustrate the different frequency performance during the NSW peak demand period on 10th Feb 2017. Oscillations of over 100MW can be observed on the synchronous unit.

Asynchronous units do not oscillate with frequency - synchronous units do. Control of frequency is a fundamental requirement for the good operation of synchronous units, without it they are at risk of loss of synchronism which can cause catastrophic damage to them.

Synchronous units are at risk of pole slipping or/ and shaft damage when significant power oscillations occur within the system. This is why Good Electricity Industry Practise requires sensible tight control of frequency. The current rules surrounding the frequency control on the power system have made this control feature a commercial choice not as a physical mandatory requirement. While it is possible to operate the power system without all units providing frequency control, it is necessary to ensure that there is always sufficient and adequate frequency response in all regions at all times. The market does not guarantee that this is the case.

Contingencies occur in all power systems and it is the role of the system operator (AEMO) to prepare the system for the expected conditions that may arise on the power system. “Monitoring” is not sufficient and should not be accepted as a reasonable position to take. In a gas market, the operator has days to monitor a situation due to pressure in pipelines. In contrast, in an electrical power system events happen in seconds and there is no time monitor! The system must be operated in a manner that it can withstand events. This includes abnormal weather events, such as lightning, cyclones, and peak load conditions.

The new technologies, such as wind and solar, when correctly controlled provide a stabilising effect to the power. They do not respond or contribute to oscillations such as the ones that occurred on 10th February 2017. This is because they can operate with a variable frequency. A synchronous unit, on the other hand, requires tight frequency control to remain synchronous, and failure to stabilise the frequency translates directly to the speed of the shaft of these units. The system black analysis has included analysis of the “transient response of wind turbines”, but it has failed to analyse the transient behaviour of the synchronous units. The analysis is dismissive[2], it accepts the behaviour because the market lets the units behave that way. The synchronous units had the head room to provide for the contingent losses from the wind farms but the control systems were not active and even if they had of been, the control action would have been too late because of the market settings.

This was not always the case and the units in SA have in the past successfully responded to much larger events - the difference is the control settings.

4.3 Is there a need to introduce new planning and technical frameworks to complement current market operations?

The current market framework has created regulatory penalties on generators for providing good frequency control. It is the existing market operations that require reform, further overlays of “new services” will complicate the problems unless the fundamental control situation is corrected.

[2] Page 42 AEMO third preliminary report.

A review of both the market and the technical rules for frequency control is required but such reviews must be undertaken with technically competent engineers and rules must be appropriately evaluated for their effect on the power system. Rules negotiation and submissions are often heavily influenced by commercial interests as if this will suit the power system. Unintended consequences and deterioration of actual control are difficult to predict but must be identified and corrected.

In the USA there is a Federal Energy Reliability Council (FERC) with a complementary body North American Electricity Reliability Corporation (NERC). These bodies set the technical rules for what generators can and cannot do on power systems. The USA has retained a strong engineering focus. In contrast, Australia tends to make rule changes with limited power system engineering analysis or input.

It would be better if Australia established an independent overarching technical engineering body that focusses on the control of the power system and provide the limits to the commercially driven aspects of the market. The role of the independent system operator combined with the role of the independent market operator was intended to perform this function.

The function of AEMO under the NEL and the NER includes the responsibilities for power system control function and the market operator function. Since the merger of VENCorp with NEMMCO to create AEMO it would appear that the "market operator" function is taking precedence over the power system control functions. Since market inception, the NEM by design placed the system operator function in the same room as the dispatch function in order to ensure that the market did not overwrite good control practice. In the USA, the functions are often operated out of different locations, and this was not considered good practice in Australia. However, it would appear now that the influence of market control has become dominant and power control has taken a back seat.

The co-ordination of the power system control and the specialised engineering that focussed on the power system control has been systematically fragmented. This cannot continue. The transition to the clean energy future through the market will not guarantee the co-ordination necessary to maintain system stability unless appropriate engineers and engineering principles are restored.

4.3.1 Should there be new rules for generator connection and disconnections?

The decommissioning of large power stations in Australia was once under the central planning of the public utility. This is no longer the case. The decommissioning of Hazelwood power station in Victoria raises interesting questions that illustrate the complexities caused when a private operator is able to take such a decision. First, there has been much media commentary around the step change in wholesale electricity prices in Victoria following the announcement of the closure. The owner making such a decision may experience a different commercial impact to the rest of the market. Faced with escalating operating costs, the owner is in a unique position to anticipate the impact on market prices of the announcement of the closure on the remainder of the owner's generating assets.

Secondly, the owner is able to take this decision regardless of the size of the power station being closed. In the example of Hazelwood, the largest single unit in the region is 520MW and yet the market is facing the potential removal of 1600MW all at once. This is a significant potential step change, both in terms of impact to the power system and the consequent loss of inertia, and in terms of the financial impact to customers. Given the possible impact on the whole market, there is an argument for the introduction of some rules to govern such disconnections.

While the open access arrangements on the transmission and distribution systems have enabled much new investment in the power system, there is the possibility of large generation projects in limited grid areas affecting all connected parties and undermining the business case of existing generators. It may be time for the Rules to set some limits to the impact that new projects can have on transmission constraints (and neighbouring generation). At this point in time there is no limit, although originally the Rules did place an obligation on network service providers to consider the impact on other generators.

4.3.2 Should all generators be required to provide system security services or should such services continue to be procured separately by the power system operator?

It is difficult to know exactly what is intended by “system security services” as the words “system security” are held up and used to justify all manner of action in the market, sometimes without sound engineering reasons. Perhaps the question is “should all generators provide grid support services”, in which case the answer is ”yes”. How else will energy be transported to market? In most energy markets, the ancillary services necessary to support the trade in energy are not acquired through a market mechanism.

The minimum performance standard in the NER is designed as a “do no harm” standard and as such the operation of any generator should never do harm. The automatic standard is the highest level of performance that can be asked of a generator and the system operator cannot and should not require a higher standard. Within this framework it is possible to right-size the performance of the units, the capability and requirements exist in the Rules, the problem is that the market allows capability (control systems) to be disabled!

If we want a strong efficient power system, then all generating units should actively contribute to supporting the grid, just as network service providers should ensure adequate voltage control capability is within their networks to support the load. This would mean providing frequency control and voltage control to the extent that is suitable for the plant and its location on the network.

Large generators on the backbone of the transmission system should provide more of the control action and smaller generators in weaker parts of the grid should provide lesser control which need not be as much as those on the back bone. All control should be damped and stable. Recent events illustrate that the frequency control of the synchronous units is not stable, damped or well controlled and indications are the units are hunting against one another. This is a greater risk to the “system security” than any amount of renewable energy.

4.4 What role can new technologies located on consumers’ premises have in improving energy security and reliability outcomes?

All behind the meter generation, such as co-generation or locally installed solar panels, are only a risk to the power system if they act collectively instantaneously in either direction. Given the dispersed manner and non-uniform types, this is unlikely to occur. Some practical suggestions regarding response to frequency events would be to ensure that local generation with over and under frequency settings, should have some logic in combination with the local load. That would ensure retention of load (trip of generation) for over frequency events and to the contrary retention of generation (trip of load) for under frequency events.

4.4.1 How can the regulatory framework best enable and incentivise the efficient orchestration of distributed energy resources?

There is a significant push to engage customer “action” in the market; this is acceptable when everything on the power system is normal. However, when power system events occur, the prices often change dramatically, and a market response during an event to price changes may not be consistent with ensuring system stability. It can cause unwanted deviations in a region which can exacerbate the control of the power system, risking security. This happens at the macro level now and will be repeated in the micro level if distributed resources only respond to price. When significant events occur in the power system, market responses that may exacerbate the event should not be permitted.

Otherwise encouraging small distributed solutions that are the right size for local loads is ideal. The current market contains incentives to do this although it is currently at the wholesale market level.

4.5 What other non-market focus areas, such as cybersecurity, are priorities for power system security?

Cyber security must not be ignored as all new digital control systems are often supported through supposedly secure communication networks.

4.6 How could high speed communications and sensor technology be deployed to better detect and mitigate grid problems?

High speed communications and monitoring is deployed on the power system - this is the SCADA system. What is failing is the primary control systems which must be enabled locally on the units. Given that electrical charge travels a little below the speed of light, remote control (such as market dispatch) will never be able to replace local control systems on units (which can respond much faster than remote control systems)and it should not be expected. Communication systems are prone to congestion and failure particularly when a system event occurs. Local dual redundant controls are good electricity industry practice. It is disappointing that good controls have been abandoned without proper analysis of the impact on the system.

4.7 Should the rules for AEMO to elevate a situation from non-credible to credible be revised?

The market has operated since 1998 through to around 2013 without problems over the “reclassification”. The need and the authority of the control rooms to act to protect the power system has been a constant since the start of the NEM. The only thing that appears to have changed is interpretation and re-writing of procedures which have had a limiting effect on when such reclassification can take place. Such limits should not exist as no one can predict catastrophic events, for example when an airplane crashes into lines, or a system transformer faults.

There are an infinite number of contingencies which cannot be predicted or covered in a procedure. The system operator should not be expected to have limitations on reclassification. The ability to manage the power system for any abnormal condition is via the reclassification. This method is based on the premise that something that is outside the normal planning envelope for the power system is now considered possible, therefore, the system operator has to do something abnormal in order to manage it. Any action taken must be necessary to secure the system and it should be possible to show this after the event.

On September 28 2016 it has been said that there was no requirement to reclassify the interconnector as there were no “vulnerable” transmission lines in SA. Such statements illustrate a lack of understanding of system dynamics. Interconnectors are at risk of dual circuit tripping if large contingencies (such as the loss of the whole of Northern Power Station (as occurred in March 2004 and 2005) or when contingencies cause angular separation between the states. Extreme storms always cause multiple contingencies.

When events occur in a power system, control systems must be active and the control operator must have already acted to protect the system. Failure to prepare the system for possible events given an extreme weather forecast, a bushfire, a storm, or a flood, is not an option. Appropriately trained system operators who can think and act ahead of the event are vital to maintaining the security of the system. Loss of experience or lack of training or any reduction in the authority of the control rooms to act to protect the power system must be avoided. Well trained operational engineers in combination with experienced system operators cannot be replaced by automated systems if abnormal conditions are to be managed. Cost cutting exercises replacing staff in the control room is false economy as additional trained operators are always required in abnormal conditions.

Finally

Please consider the training of electrical engineers to ensure appropriate skills are being taught in the universities. Since the mid-nineties, power systems and control engineering, has not been a widely available course and very few students are being provided the opportunity to study this discipline within Australia.

3. Attachment