Fast Frequency Service – Treating the symptom not the cause?

This paper will raise questions regarding the FCAS[1] market structure and its influence on the deterioration in the frequency control of the power system with respect to regulation and in response to fast events.

There have been recent discussions in various public forums relating to the Australian National Electricity market about introducing a fast frequency ancillary service and/or an inertia service market additional to the existing 6-second, 60 second and 5 minute markets.

This paper will demonstrate that good frequency response has been penalised under both the Causer Pays cost allocation regime for regulation service and the energy dispatch requirement for generators to ramp in a linear fashion between dispatch targets within the NEM[2]. The culmination of fifteen years of economic decisions combined with control system upgrades and compliance obligations have reduced the frequency response of the power system.

The lack of fast acting arresting energy represents a significant deviation from Good Electricity Industry Practice and fails to meet the National Electricity Objective requiring more services to be dispatched than would otherwise be required if the systems services were re-designed. The real time market management of frequency services has downgraded the safety nets that were designed to avoid system collapse and may mean that existing system constraint limits are incorrectly calculated.

An appropriate reassessment of the market framework for frequency control within the NEM should be undertaken to address the significant loss of performance and power system control.

Introduction

Australia is unusual in that it has created a real time market for the provision of all of its frequency control. The decision taken in 1999 to introduce markets for Ancillary Services to manage the provision of frequency control within the NEM is in contrast to other electrical power systems where frequency control is managed through fixed services with a level of mandated requirements.
A re-assessment of the NEM frequency control ancillary services (FCAS) markets should be undertaken. The governor control that was required prior to the start of the ancillary services (FCAS) markets illustrates why there appears to be a serious decline in the ability of the power system to withstand significant events. The introduction of a market structure and the separation of various ancillary services has brought with it a level of risk which has been highlighted by the system black that occurred in South Australia on 28th September 2016.

It is time to re-examine the technical risk and inefficiencies introduced by a culmination of more than a decade of decision making (and flow-on regulatory changes) which have led to a significant decline in the primary frequency control systems on the synchronous units within the NEM. Many other markets treat ancillary services that are necessary to support the energy trade as part of the mandatory requirements, this is in contrast to the NEM in which the frequency control is optional and economically sourced[i].

[1] FCAS – Frequency control ancillary services
[2] NEM- National Energy Market

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Brief Overview of the FCAS Market design

The current FCAS markets are designed to deliver regulation services only within a defined normal operating band ranging between 49.85 to 50.15 Hz. Regulation control is a relatively slow control loop designed to correct small frequency deviations and time error. On the mainland interconnected system, the contingency services are designed to ensure that for a single contingency (loss of generation), the excursion is arrested before the frequency reaches 49.5Hz, (or for load rejections) 50.5Hz. When the FCAS markets were introduced the principle that frequency services were to be obtained on an economic basis, meant that mandatory requirements were removed from the rules, and wording was introduced to the NECA[3] code that structured the services in a manner consistent with the understanding of service type. The NEMMCO[4] paper on the Optimisation of Regulation and Delayed FCAS (Oct 2002) summarises the service types that were introduced in Oct 2001:

> "There are four types of FCAS, each with a raise and lower component, depending on whether the service is required to raise or lower the frequency of the power system:
>
> - regulating raise / lower, used to contain routine frequency fluctuations on the electrical system within a frequency band centred on 50 Hz;
> - fast raise / lower, <u>used to arrest a sudden change</u> in power system frequency <u>within six seconds</u> following a major contingency, such as the failure of a generating unit or transmission line;
> - slow raise / lower, used within sixty seconds following a major contingency to stabilise the power system frequency around the arrested frequency level; and
> - delayed raise / lower, used to restore the power system frequency to normal operating levels within five minutes following a major contingency. "

Cost recovery for regional frequency control services for contingency response was introduced during 2003, and later the regional cost recovery of regulation services was introduced to deal specifically with the introduction of Tasmania to the NEM. The recovery of regulation costs follow a "causer pays" principle with an allocation of some costs to generators to, "give a <u>significant incentive to better and more smoothly follow despatch instructions</u>. Whilst in principle this approach is supported as providing efficient price signals[ii]".

The underlining in the quoted section of text above is done to highlight two points, the 6 second service was intended to provide arresting energy to the system – that is the fast acting insertion (or extraction) of energy that contributes to arrest the fall in frequency, and the causer pays regime was introduced as a cost to generators to provide an incentive to "better and more smoothly follow their despatch targets".

Market decisions in the NEM are frequently undertaken by consultation which can be strongly influenced by seeking outcomes driven by an economic imperative.

Power system control specialists may or may not been have been involved in the decisions and as such the risks to the power system may not have been fully assessed prior to allowing control changes to occur under the new rules.

It would appear that some side effects of the FCAS decisions have taken more than a decade to manifest. Warnings that the removal of the mandatory deadband requirement would lead to generators disabling governors were not heeded in 2001, possibly due to the strength of the frequency control and the stable and abundant control that was inherent in the system at the time.

Thus, the decisions taken by NEMMCO following the work by the Ancillary Services Reference Group in 1999[iii] to remove the mandatory governor response requirement at the introduction of the FCAS market in combination with the code wording that divided the services into neat categories has resulted in a progressive removal of primary governing response from the normal operating band.

The FCAS market has resulted in a system that accepts only regulation control within the normal operating band and somewhat artificially divides up the contingency response into discrete services.

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[3] NECA – National Electricity Code Administrator, which was a forerunner to the AEMC (Australian Energy Market commission)
[4] NEMMCO – National Electricity Market Management Company, which was a forerunner to AEMO (Australian Energy Market Organisation)

In control hierarchy, the regulation service is a secondary service which is controlled by the centralised Energy Management System (EMS) via the Automatic Generation Control (AGC). It is a slow control loop that is affected by time delays in communications, and works off an error calculation of frequency measurements to send signals to units to increase or decrease their outputs. It is much slower than a first order primary control which is normally performed by unit governors.

The contingency services are designed into the governor settings which define when primary speed control of the generators will start and stop. The implementation of this design has meant that in many cases governing control is switching in and out, when originally this was meant to be a continuous control action.

The market design makes the assumption that the contingency service only BEGINS when the frequency deviates outside the normal operating band. This assumption along with the associated Code wording has allowed (over time) the governor deadbands to be moved from the original less than 0.1Hz out to 0.3Hz or larger. While it may look like a small change, in electrical terms this is a significant change in the timing and response of the synchronous units to contingency events. It means that more contingency service is required to arrest a fall in frequency than if the service began within the normal operating band.

The NECA Code at the start of the market contained the following section (S5.2.6.4) on governor control for scheduled generating units, (the entire section is available in the Appendix 1 to this paper).

> The deadband of a *generating unit* (being the sum of the increase and the decrease in *system frequency* before a measurable *change* in the *generating unit's active power* output occurs) must be less than 0.1 Hz.

And,

> When a *generating unit* is operating in a mode such that it is insensitive to *frequency* variations (including pressure control or turbine follower for a thermal generator), the *Generator* must apply a deadband of not greater than 0.25 Hz to ensure that the *generating unit* will respond for *frequency* excursions outside the *normal operating frequency band.*

The FCAS market introduced the following code wording deleting S.5.2.6.4 completely (see Appendix) and replacing it with clauseS5.2.5.11, which states in (c) and (d) that:

(c) A *Generator* must ensure that each of its *scheduled generating units* is capable of automatically reducing its output:

(1) whenever the *system frequency* exceeds the upper limit of the *normal operating frequency band*;

(d) A *Generator* must ensure that each of its *scheduled generating units* is capable of automatically increasing its output:

(1) whenever the *system frequency* falls below the lower limit of the *normal operating frequency band*;

Co-incident with these decisions, the Reliability Panel increased the bandwidth of the normal operating band arguing that this would be more economic. The band was changed from a normal operating band (49.9Hz to 50.1Hz) to a wider band of (49.85Hz to 50.15Hz). These changes allowed the control systems to be adjusted such that the primary governing response only started after the frequency had fallen below 49.85Hz.

The removal of primary governing response from within the normal operating band means that there is no primary governor control available for smaller contingent events such as a 100 MW loss of generation as these events do not cause the frequency to fall low enough to trigger governor action, the response to these events is purely inertial and then second order regulation response only. This is a significant departure from the pre-market control philosophy, and it leaves the power system exposed when several smaller contingent events occur in quick succession such as occurred in South Australia on 28 September 2016.

This is permitted by the rules that apply, but as recent monitoring reports show this is now failing to provide efficient frequency control of the power system and due to the deadband changes has increased the risk to system security causing impairment to the fast acting frequency response. As a side issue it also has detrimental effects on some system loads.

Pre-FCAS vs Now

The combined effect of these decisions has culminated in an undesirable loss of primary governor control within the normal operating band. The following chart provides the frequency distribution comparison for the same day fifteen years apart. The Reliability Panel referred to the frequency distribution on the 8th May 2001 when they were re-setting the frequency standards. Using the 4 second systems frequency data for the 8th May 2016 and overlaying the original chart, the results highlight a significant change in the frequency distribution.

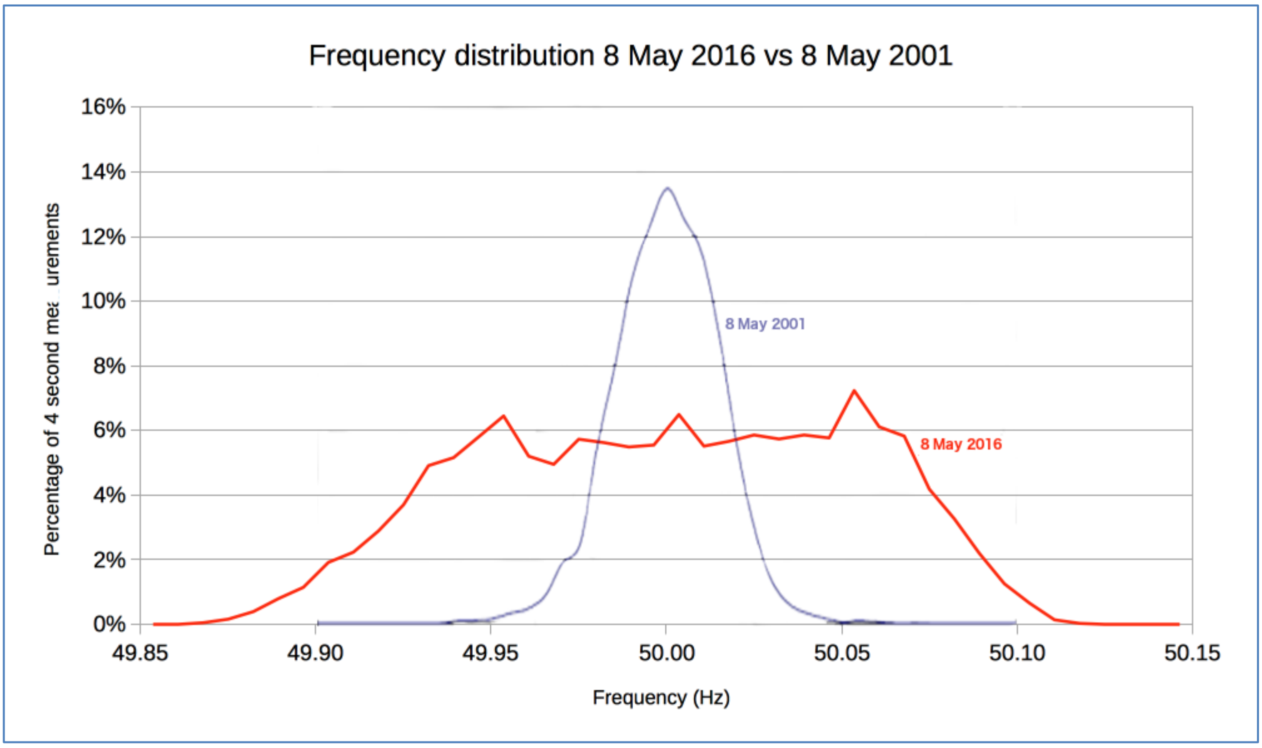

Figure 1: 4 second data Frequency Distribution for 8 May 2001 versus 8 May 2016*

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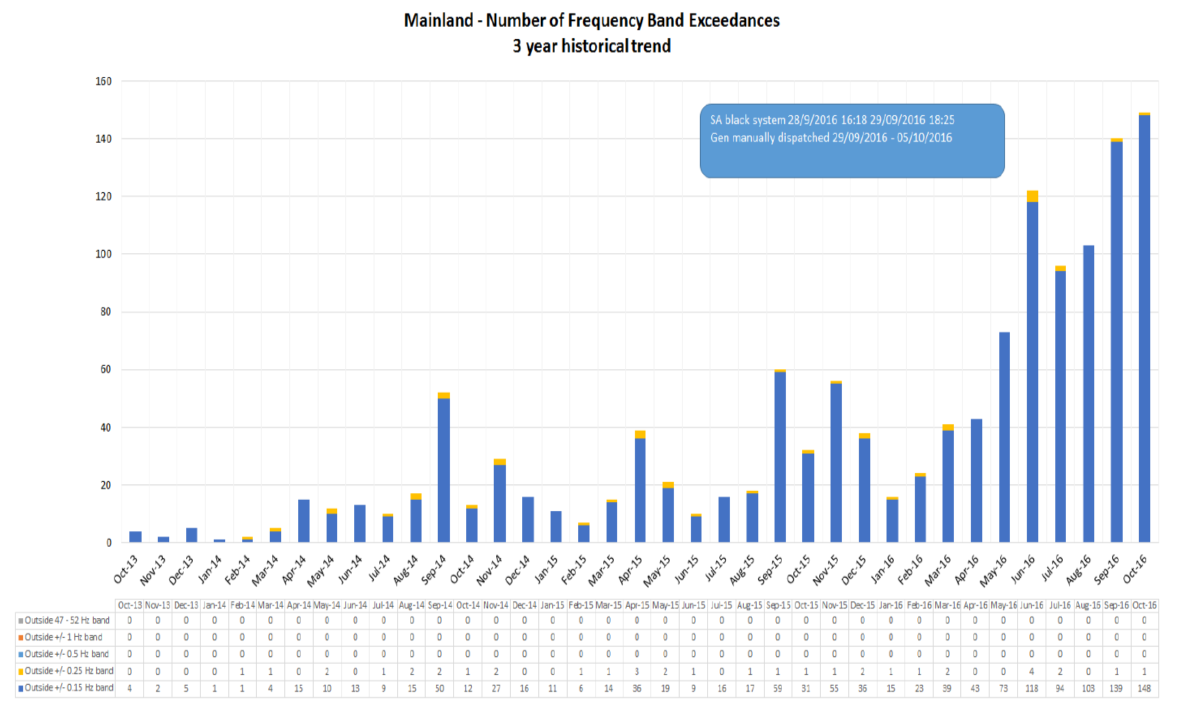
The change to the governor deadbands in clearly evident in the frequency distribution, it is further illustrated by AEMO's Frequency Monitoring - Three Year Historical Trends report figure 2.2. This chart shows the deterioration that is occurring in the number of times the frequency is exceeding the normal operating band. It illustrates an alarming growth in operating band exceedance events.



	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15
Outside 47 - 52 Hz band	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside +/- 1 Hz band	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside +/- 0.5 Hz band	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside +/- 0.25 Hz band	0	0	0	0	1	1	0	2	0	1	2	2	1	2	0	0	1	1
Outside +/- 0.15 Hz band	4	2	5	1	1	4	15	10	13	9	15	50	12	27	16	11	6	14

	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16
Outside 47 - 52 Hz band	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside +/- 1 Hz band	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside +/- 0.5 Hz band	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside +/- 0.25 Hz band	3	2	1	0	1	1	1	1	2	1	1	2	0	0	4	2	0	1	1
Outside +/- 0.15 Hz band	36	19	9	16	17	59	31	55	36	15	23	39	43	73	118	94	103	139	148

Figure 2-2 Mainland – Number of frequency band exceedances

Figure 2: Mainland – Number of Frequency Band Exceedances[iv]

Integration of renewable energy has increased during this time, and the deterioration of the frequency control is often blamed on asynchronous machines associated with wind farm generation. To highlight why this casual factor is not solely responsible for the deterioration, consider the example of frequency control on 1 November 2015 in South Australia. The wind power outputs remain stable and hence are not responsible for the changes in frequency that occurred for this event.

Figure 1: South Australian frequency

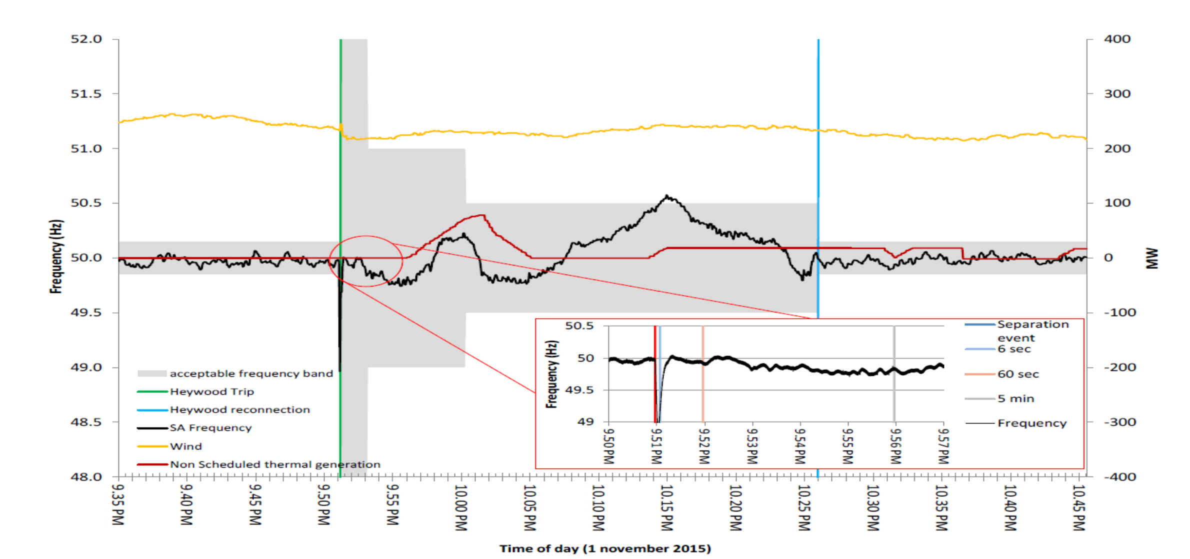


Figure 3 AER: South Australian Frequency during separation

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Generator owners have found that maintaining the original governor bandwidths that were mandated at the start of the market have caused costs and penalties within the current regime. Before these are discussed in detail, it is worthwhile understanding what good frequency control involves. The pre-FCAS market performance provides an insight into how frequency was managed.

Prior to the introduction of the FCAS markets, the NEM had mandatory governing requirements which were based on the power system control requirements of the participating jurisdictions in the NEM. The frequency control bands were tight with the original normal operating band defined as being 49.9 to 50.1 Hz. (This was changed on 30 September 2001 to 49.85 to 50.15 Hz with a probabilistic tolerance for the band of 99 % of time. When setting the change in the standard the Reliability Panel acknowledged that the setting of the standards represented a trade-off between quality, security and cost[v].)

In the same document the Reliability Panel also stated:

"Keeping the frequency so close to 50 Hz has several benefits:

- _it provides reasonable certainty for the starting point for any disturbance, allowing the amount of contingency services to be determined on the assumption that frequency is close to 50 Hz prior to the incident;
- it minimises the chance that frequency will exceed the normal band for simultaneous occurrence of minor load and generation changes;
- time error is much easier to keep within specified limits if it is not usually being accumulated; and
- keeping the frequency close to 50 Hz and within the governor deadband permitted by the Code (+/- 0.05 Hz) minimises wear of governor systems and therefore generation costs."

The Reliability Panel acknowledged the function of keeping the frequency tight, but they failed to state that it is established power system control practise for governing control action to start quickly at the beginning of a frequency fall. Due to the time taken for actuators, servos and other controlling devices that enable a unit to increase its energy input, it has been industry practice for the control settings to be set close to 50 Hz in order for the arresting energy to be quickly available to assist in the event of rapidly falling frequency. If governor action is delayed for any reason, then a larger amount of contingency service must be enabled in order to arrest the fall in frequency.

The comparison chart below shows that at the start of the NEM, the governors had tight deadbands, the Code made it mandatory to have a deadband even when on turbine follower (or in any other mode that was insensitive to system frequency), and that tight frequency control was required.

Comparison of Pre and Post FCAS

The table below summarises the changes that have occurred in the regulatory environment as the FCAS market was introduced and evolved to the current arrangements.

Pre FCAS at start of the NEM:	**Post FCAS Market**
The normal operating band was 50.1 to 49.9 Hz	Widened the normal operating band to 50.15 to 49.85 Hz
Normal operating band was wider than the governor deadbands (deadband < 0.1 Hz),	Shifted the deadbands to outside the normal operating band,
The primary frequency response of the units commenced before the frequency deviated outside the normal operating band.	Removal of primary governing response from within the normal operating band, in many cases.
Mandatory to have a deadband of 0.1 Hz (+/- 0.05 Hz)	Removed the mandatory deadbands
Mandatory in a mode that was insensitive to frequency to have a deadband of 0.25 Hz (+/- 0.125 Hz)	Removed mandatory deadband on governor response when in a mode that is insensitive to frequency

Pre FCAS at start of the NEM:	Post FCAS Market
Primary governing response was available within the normal operating band assisting with reducing the amount of regulation service (AGC) required.	Primary governing only commences outside the normal operating band, only AGC – Regulation service act within the normal operating band. (This increases the amount required and decreases overall efficiency.
Governors were tuned to provide a fast step change that was adequately damped and proportional to frequency, (frequency was not driven off 50 Hz)	Governing response is only required to be sustained in accordance with the MASS.
Unit overload capability available to the system.	Loss of unit overload capability, slowed response caused by the implementation of the FCAS trapezoid using digital control methods.
Droop governor control active in normal operating band	Droop governor action penalised when taking units off dispatch target.

The following Figure 4 illustrates the changes that have been enacted by moving the deadbands to outside the normal operating band. This makes the primary governor action slower and can make it ineffective when large contingencies occur and is non-existent for small contingencies. Requiring a unit's performance to match a fixed FCAS offer may also reduce the response of a unit to an event. This may be deteriorating the management of large events on the system. As system inertia is reduced and the system becomes lighter, the speed with which frequency can change increases. Delaying the governor action with wide dead bands greatly increases the risk to the system.

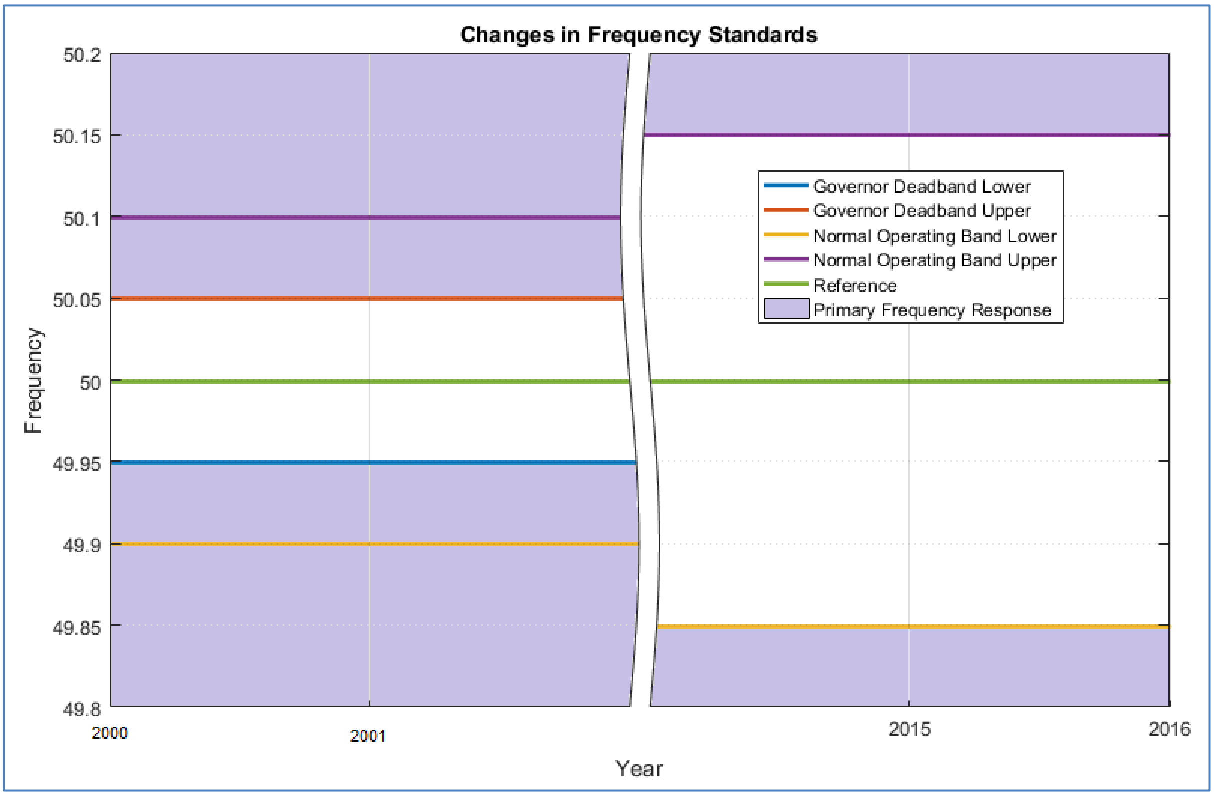


Figure 4: An illustration of the changes to the Operating Band and the Governor Settings.

The benefits of tight frequency control

When the governor on a synchronous unit senses a reduction of rotational shaft speed, the governor control system will act to increase the energy into the unit to speed it up again. To the governor the speed deviation from 50 Hz indicates that the power out of the unit is higher than the mechanical power in, so it is acting to correct the balance of the unit. Tight governor deadbands ensure that the unit's action starts early, and is more effective. In addition to delays resulting from the governor deadbands, there are delays associated with the actuators which must operate to increase energy to the unit's turbine. If a deceleration commences and sets in prior to the unit starting this action then it is much harder to arrest the deceleration as some of the machine's momentum has been lost.

An analogy to this would be a truck requiring a run up to maintain its speed as it goes up a hill, it must accelerate (or increase its energy input) early enough to maintain the momentum, once the truck slows down it cannot easily regain its speed and can only change gears down and crawl up the hill, or worse stall.

A tight deadband on a synchronous unit means that the fast acting arresting energy against a sudden step change of load on the unit's terminals will occur before the deceleration sets in. Widening the deadband means that the arresting energy will come later or may not be triggered at all in which case the frequency correction is only controlled by slow acting regulation services. Removing the deadband and disabling the governor action would mean that the unit is non-responsive to system frequency. In effect, this removes spinning reserve from the system as any head room on the unit cannot be provided in real time.

To be clear, the governor action provides the primary frequency control of the system, the Reliability Panel in 2001 recognised that "Frequency must be managed on a second by second basis, far faster than any market mechanisms can deliver." Recent market publications highlight the current operational philosophy which has the market controlling the frequency response through inertia[vi]. All rotating machines have inertia due to their rotating mass. The kinetic energy in the rotor of a synchronous machine can be extracted through the electromagnetic coupling of the machine to the grid. A sudden increase of load on the unit creates an inertial energy contribution, however, extracting electrical energy out of the rotating mass results in the rotational mass slowing down. This is caused by an unbalance between the electrical energy out and the mechanical energy into the unit. (ie: load on the terminals is greater than power into the unit). When there is no primary governor action to increase the mechanical energy into the rotating mass the deceleration will continue as there is nothing correcting the unbalance. On an isolated system this would lead to collapse. Governor action that commences early contributes to ensuring the frequency nadir is not unreasonably lower than expected.

Frequency control cannot be achieved using inertia, because inertia only changes the rate of change of frequency it has no effect whatsoever on the control of frequency.

The AEMO discussions on inertia markets in 2016 appear to be without any consideration as to whether the synchronous units have appropriate governor settings, whether there is any governing action enabled and available at all times and in all regions. It is also critical to understand the impact of removing the mandatory deadband settings from synchronous units that are on turbine follow mode (or otherwise insensitive to frequency), these units become dependent on the external system fixing the unbalance for them. The original Code contained a mandatory requirement for a wider deadband on these units, to make them respond to frequency for larger deviations. The removal of the mandatory deadband could be equated to removing the UFLS obligation on load. It is the safety net provision from generators, without it, the only safety net is load shedding. This exposes customers to unnecessary risk loss of supply.

6 second FCAS, switched or continuous control?

In a number of recent public reports it is stated frequently that the "The minimum time for FCAS service to act is six seconds[vii]" – this indicates that the current understanding of the 6 seconds service is that it takes 6 seconds to commence, whereas in 2001 the understanding was (and should be) that the 6 second service has to be provided "within 6 seconds". While it is true that the full delivery of the service can take 6 seconds, the speed and timing of when the action begins with respect to sudden change in frequency is important. Units that have provided fast acting services increasing their energy in proportion to the frequency deviations have progressively detuned their controls so that they are not found to be non-compliant with their dispatch instructions[viii]. Loss of governor droop control removes an important primary control action from the system, while the switched controllers for the different FCAS services can fight against each other. This has come about because the market considers frequency events to be discrete when frequency is in fact continuous and dynamic. It should be noted that loss of governor droop control has implications for system restart, as units on speed control will hunt against each other without it. Droop control with a mandatory deadband is common electrical industry practise and further references will be given later in the paper.

Control System Changes – Digital Controllers and Market Enablement

Developments in control system technology means that newer digital governor controllers are now able to receive external control signals that can alter the mode of control of the unit in accordance with market dispatch. This was not a feature that was common at the time the FCAS market was designed. Governors and unit controllers in 2001 were still mainly analogue controllers that were not connected to the internet or local area networks (LAN), as such it was not possible to alter in real time the mode of control of a unit.

The large synchronous units were permanently operated in accordance with the tuned governor settings provide by system control engineers. Upgrades to the governors over the last decade now mean that the units can have their mode of operation altered between providing frequency control and not. As the rules fail to prescribe a mandatory deadband for the units that are not enabled for frequency control then the contingency response of those units may no longer be available to support the system. Without mandatory governor deadbands it is no longer possible for system planners to rely on the response of the synchronous units as the response (and location) will depend on the market enablement.

Contingency Response and Transfer Limit Calculations

Planning and design of the contingency response of the power system uses the dynamic models which in most cases include the governor response. Transfer limits between regions rely on identifying the limit of transfer that can be achieved without loss of stability or synchronism between regions. These calculations rely on accurate control system modelling, if the market enablement is altering the control system modes of the synchronous units and moving the location of where the primary frequency response is available within the system then the constraint equations that control the network flows are unlikely to be within a safe operating margin. Evidence that this is occurring is illustrated in Appendix 2

Risk to the Safety Net

The original deadbands for unit responses were included in the model used for the design of the load blocks for the under frequency load shedding (UFLS) schemes. Changes to the deadbands of the units would result in nullifying the mathematics underpinning the design and increase the risk that the Automatic UFLS safety net could fail to operate. Recent reviews of UFLS would have had to have taken into account the loss of primary governor response within any region and in particular for low inertia regions. This is because widening the deadbands delays the injection of arresting energy allowing the synchronous units to lose momentum and for the frequency to decline rapidly in a manner not considered when frequency setting and the time delays of the load blocks were set.

At the time the Jurisdictional Security Co-ordinator in South Australia made the determination regarding the use of automatic UFLS in lieu of raise contingency services, the units all had mandated deadbands and were required to respond to contingency events in accordance with those deadbands. The operation of the UFLS was rare and only occurred for non-credible contingencies. Widening of the deadband and disabling governor response, significantly alters the depth of the frequency nadir, and relies on all contingency responses being provided over the interconnector, greatly increasing the use of UFLS. November 1 2015 was the first time UFLS had been triggered for a credible contingency.[ix].

Penalties for good frequency control

There are two disincentives created by the current market regimes which work against tight governor control, these are the causer pays calculation and the expectation that a unit should ramp in a linear fashion between dispatch targets.

Causer Pays Factor

The causer pays regime is intended to allocate the cost of the FCAS regulation services to loads and generators. The reason it was applied to generators was to provide incentive "to better and more smoothly follow their despatch targets" as described earlier. The causer pays factor (CPF) calculates a factor based on figures that are derived from the market enablement for regulation services to assess whether a unit is acting in a positive or negative fashion against the Frequency Indicator "FI" figure. The FI factor equates to a calculation associated with the Area Control Error and the integral of that within the AGC system (see Appendix 3). It is not a measurement that is readily available to participants, and so it cannot be used in a real time control system on a generating unit to eliminate or minimise a unit's causer pays factor. This is fundamentally flawed as the performance of a unit to frequency should be the primary objective of frequency control.

A unit's performance is assessed using 4 second SCADA data measurements of the output of the plant. Such measurements are unable to measure correctly a unit's actual frequency response. SCADA data is delayed by communication paths and is often delayed by many seconds, this has been independently measured to be anywhere from about 15 to 40 seconds. An actual frequency response would require a faster sampling rate and compare the unit's response against actual measured frequency. Synchronous units with tight deadbands have found that they were being penalised with poor CPFs even though they were actually supporting good frequency regulation. When providing primary frequency control within the normal operating band, the 4 second measurement (and associated poor communications) fails to measure the frequency response correctly and has allocated cost to the units that are actually responding to frequency changes.

Energy Market Dispatch, a pure ramp?

Another penalty occurs due to the energy market assumption that units would ramp between one dispatch interval to the next in a <u>linear fashion</u> and be accurate to their dispatch targets. This has inadvertently penalised units for providing <u>primary governing response</u> within the normal operating band and the 5 minute dispatch interval. A unit with a tight deadband would respond to correct the system frequency, meaning that it is necessary to deviate from the energy ramp to correct for load changes and forecast errors that made the system frequency exceed the deadband. To fix this compliance problem, synchronous units have progressively disabled their governors and widened their deadbands so that they simply follow a prescribed ramp. Hence a unit that is enabled for contingency service will provide no primary governing until the frequency has exceeded the normal operating band and within the normal operating band it will follow its dispatch target.

Suggested New markets

Implementing another market for fast frequency response will result in similar issues described in this paper unless the market and the regulations are altered to incorporate good frequency control into the normal operating band. This approach appears to be ad-hoc and likely to lead to further complications.

As a general principal the authors believe that Frequency services should not be switched between services but be continuous just as frequency is dynamic. Other countries do not allow the disablement of governor deadbands or droop settings. The USA PJM has a mandated deadband of +/- 36mHz[x]. The UK Grid Code has the same normal operating band as the NEM but mandates a deadband of 30mHz (for avoidance of doubt +/- 0.015 Hz)[xi] and a Droop setting of between 3% and 5%. Further research of grid codes would produce similar results. The NEM has droop requirements specified in the technical standards, it is a required capability, but it would appear that the market has progressively pushed out this control function due to the simplified expectation that market dispatch is correct.

It is time the frequency response was reviewed and controls returned to Good Electricity Industry Practise as the monitoring evidence reveals the deterioration and the technically poor control philosophy that has been adopted.

Recommendations

It is important in a lightly meshed and long network such as the NEM to maintain tight frequency control and that frequency response is available throughout the network.

- The return of mandatory deadbands to the rules such that units that are insensitive to frequency control must provide a safety net response just as load is required to.

It is critical for system stability that sufficient frequency response is available within all regions and particularly in regions with less inertia. Operating a region without primary governor control enabled on units within that region means the region is being operated without any spinning reserve, because fast generator re-dispatch in response to system frequency changes is provided by primary governor control action. Spinning reserve is not provided via the market dispatch system or by the AGC – this is too slow and unlikely to correctly allocate the reserve if the dispatch is based on economic modelling alone.

(Note: the inertial response of a unit occurs in the first swing of an event, and within several seconds the change of power must be picked up by increasing the mechanical energy into the generators without this the frequency continues to decline).

- The system stability guidelines must be understood and market mechanism must not be allowed to contradict the requirement for maintaining stable regions even when they island.
- A sufficient proportion of regional primary governing control is not optional and should not be turned off, to do so significantly alters the response of the units within a region for the purpose of calculating the transfer limits.

Reconsider the inadvertent market penalties caused by the Causer Pays Regime and the Energy market despatch requirements.

- The current causer pays methodology leads to undesirable outcomes with respect to measuring the actual frequency performance of plant. It ought to be removed or replaced with a mathematically correct assessment of a unit's actual frequency response. Under existing arrangements, a participant cannot implement a control system to eliminate their unit's causer pays factor as the unit is not directly measured against the reference frequency of the system. The generator can only measure and respond to the local frequency.
- Units that provide primary frequency control within the normal operating band are performing a necessary frequency control action that reduces the amount of regulation service required. There should be no penalty for units that provide this primary control function. The separation of services between frequency standard bands should be discarded as primary response must commence within the normal operating in order for the arresting energy to contribute to reducing the rate of change of frequency.

- To ensure good system behaviour, Fast primary control action should be valued not penalised. The faster the frequency is controlled the more efficient the overall system.

Conclusion

In conclusion, the electricity market requires a well-functioning technical framework in which to operate. If technical features are dismantled without due consideration of the implications, the market will ultimately fail in its primary purpose of supplying an essential service. Just as safety observations give an indication of how a company is tracking with respect to occupational safety, the chart provided in **Figure 2** should be a wakeup call that there is something seriously wrong in the NEM. Given that a region has suffered a system black and the analysis to date has failed to question the logic of allowing local governors to be disabled or detuned to be made unresponsive, is a sign that the prior emphasis on control philosophy has been lost. Disablement of governors within a region means spinning reserve is being held in the other regions and the security becomes more dependent on the interconnection. When the deadbands are wide, successive small contingencies which were once easily controlled are able to cause an interconnector to exceed the protection settings for angular stability. For these and other reasons the FCAS markets require considerable redesign so that primary control can be re-instated within a safer and up until recently a more normal operating band.

Appendix 1 – Underlining by Author

The NECA Code governor control requirements at the start of the market:

S.5.2.6.4 Governor System

Each *scheduled generating unit* must have a *governor system* and each *scheduled generating unit* with a rating of 100 MW and above must have a *governor system* which includes *facilities* for both speed and *load* control except where approved by *NEMMCO*. *Scheduled generating units* with ratings below 100 MW may use speed based governors where the performance with those governors is acceptable to *NEMMCO* and the *Network Service Provider*.

The remaining paragraphs of this sub-clause apply to *governor systems* of *scheduled generating units.*

A *Generator* must normally operate each *generating unit* in a mode (eg "boiler-follow" or "*load* control" mode for thermal units) in which it will respond with a change in loading for changes in *power system frequency* according to the performance requirements set out in the following paragraphs.

The *Generator* must notify *NEMMCO* whenever any *generating unit* is operated in a mode (e.g. "turbine-follow" mode) where the *generating unit* is unable to respond as set out in the following paragraphs.

<u>Overall response of a *generating unit* for *system frequency* excursions must be settable and be capable of achieving an increase in the *generating unit's active power* output of 2% per 0.1 Hz reduction in *system frequency* for any initial output up to 85% of rated output</u> and a reduction in the *generating unit's active power* output of 2% per 0.1 Hz increase in *system frequency* provided the latter does not require operation below technical minimum. For initial outputs above 85% of rated output response capability must be able to achieve a linear reduction in response down to zero response at rated output, and the *Generator* must use reasonable endeavours to ensure that the *generating unit* responds in accordance with this requirement.

Generating units must be capable of achieving an increase in output of at least 5% of their rating for operation below 85% of output. For operation above 85% of rated *load*, the required increase will be reduced linearly with *generating unit* output from 5% to zero at rated *load*. The *generating unit* will not be required to increase output above rated *load.*

Generating units must be capable of achieving a decrease in output of at least 10% of their rating for operation at all levels above their technical minimum *loading* level as advised in the *registered bid and offer data*.

<u>The deadband of a *generating unit* (being the sum of the increase and the decrease in *system frequency* before a measurable *change* in the *generating unit's active power* output occurs) must be less than 0.1 Hz</u>.

The *frequency* response and deadband values may be varied by the *Generator* with the approval of the *Network Service Provider* under the *connection agreement*. The *Network Service Provider* must consult *NEMMCO* before approving any such variations.

For any *frequency* disturbance a *generating unit* must achieve at least 90% of the maximum response to power *generation* expected according to the droop characteristic within 60 seconds and sustain the response for a minimum of 30 seconds.

<u>When a *generating unit* is operating in a mode such that it is insensitive to *frequency* variations (including pressure control or turbine follower for a thermal generator), the *Generator* must apply a deadband of not greater than 0.25 Hz to ensure that the *generating unit* will respond for *frequency* excursions outside the *normal operating frequency band.*</u>

A *Generator* must adjust the *governor system* of a *generating unit* to ensure stable performance under all operating conditions with adequate damping. The criterion for adequate damping is that following a step change in the governor speed feedback signal the *load* change transient oscillations have a minimum damping ratio of 0.4 and the steady state response is within plus or minus 20 per cent of the ideal response having regard to loading rates and deadband.

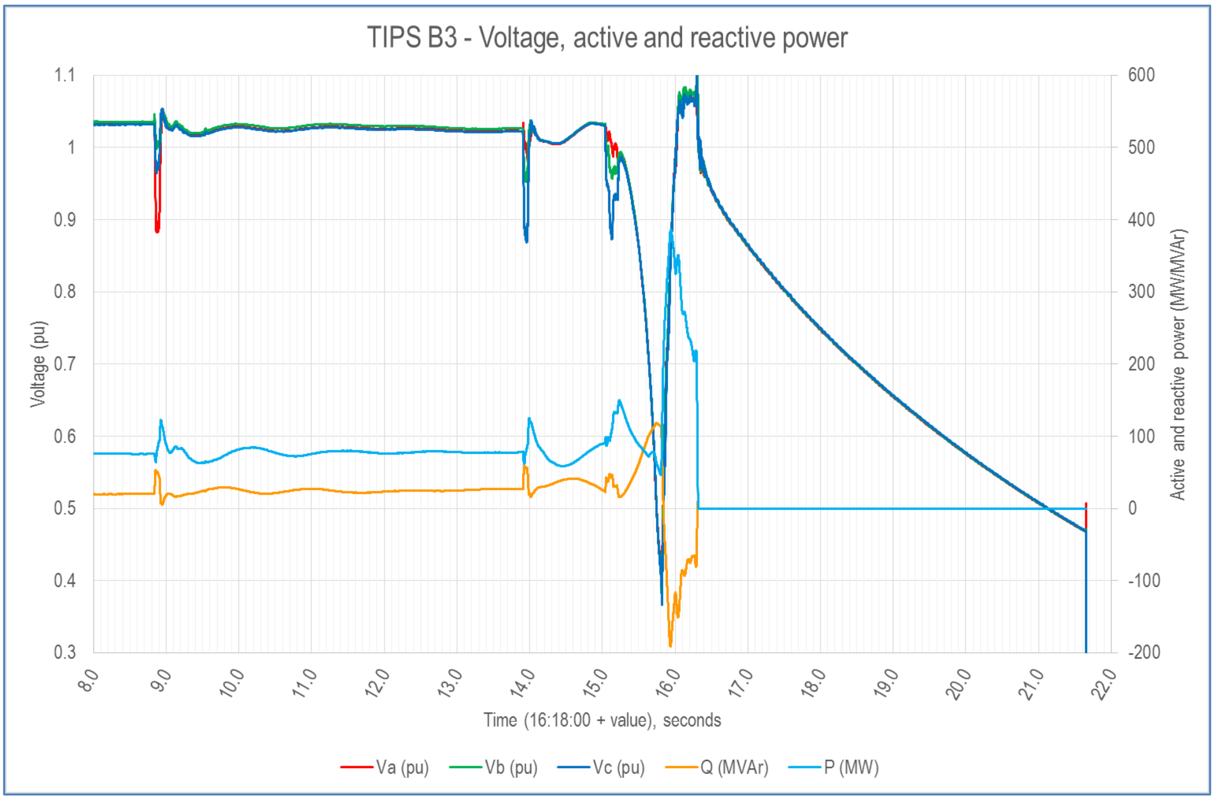
The *Generator* must advise the *Network Service Provider* of data regarding the structure and parameter settings of all components of the governor control equipment, including the speed/*load* controller, actuators (for example hydraulic valve positioning systems), valve flow characteristics, limiters, valve operating sequences and steam tables for steam turbine (as appropriate) in sufficient detail to enable the *Network Service Provider* to characterise the dynamic response of these components for short and long term simulation studies. These data must include a control block diagram in suitable form and proposed settings for the *governor system* for all expected modes of governor operation. These parameter settings must not be varied without prior approval of the *Network Service Provider*.

Appendix 2 – Model Responses versus Actual - What is Spinning Reserve – (otherwise contingency response?)

Given the recent collapse of the system in South Australia serious questions have to be asked regarding the setting of transfer limits and the market control of contingency services. While this is allowed under the rules, the implications for power system security and system studies have to be examined particularly the disablement of governors. AEMO states:

"The rapid decline in system frequency did not allow any substantial governor response from these units. This is because it takes up to six seconds for these generating units to increase their active power output by 35 MW when they participate in the Contingency FCAS market. However, when a generator is not participating in the FCAS market, the governor may be disabled altogether.[2]"

Examine T=9s and 14s the response of the unit to the event is defeated within a second the unit has returned to its pre-contingent loading, that is it provides no response to the step changes. The governors are disabled. Even during the collapse the unit is reducing its output in accordance with the market design. This illustrates that there was no spinning reserve was being held within South Australia, it was only available on the east side of the interconnector. The dynamic model provided to participants does not behave in this manner, results cannot be published due to confidential requirements.



Appendix 3: Calculation FI provided by AEMO

The FI number is a measure of the amount of regulation FCAS being deployed in a particular 4 second period. The AGC works out the total regulation number using the following logic (noting that the gains and thresholds are derived during tuning of the AGC, and can be changed by the control room if necessary due to emerging system conditions):

- FI = (ACE * ACE_Gain) + (ACE_Integral * Integral_Gain).

Where

- ACE is the area control error – and is the measured frequency error of the system expressed as MW.
  - ACE = 10 x BIAS x ($F-F_S-F_O$)
    - BIAS = area frequency bias and is tuned, but typically 6MW/0.1 Hz
    - F = current measured frequency (Hz)
    - F_S = scheduled frequency (Hz); normally 50.0Hz
    - F_O = frequency offset for system wide time error correction (Hz)
    - Expressed as an energy term in MW.

- ACE_Integral is the integral of the frequency error – i.e. the accumulated drift from where the system would have been under perfect 50Hz.
  - ACE INTEGRAL(t_n) = ACE INTEGRAL(t_{n-1}) + ACE(t_n) x (t_n - t_{n-1}) / (60 x 60)
    - Where t_n and t_{n-1} are 4 seconds apart.
    - i.e. it is the previous integral, plus the current error, weighted by the proportion of 4 second samples in an hour.

- Gains are tuned values, and change between four states in real time depending on the value of ACE itself – at very high error values, the AGC scales up the amount of regulation it deploys in response.
  - Deadband (ASE < 28) – 0.0 and 0.0 are the gains.
  - Normal (ASE > 28) – generally 1.25 and 0.8 are the gains.
  - Assist (ASE > 140) – generally 1.6 and 0.6 are the gains.
  - Emergency (ASE > 280) – generally 3.0 and 0.6 are the gains.

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Kate Summers is an experienced power systems engineer with over twenty years experience in the electricity markets of Australia. Her career covers time in transmission planning (dynamic modeling, power system control) and system operations for Victoria and later with the National Electricity Market Management Company (NEMMCO). She works now in renewable energy and has been the technical director for the Australian Wind Energy Association and the Chair of the Grid Directorate for the Clean Energy Council. Her work covers connection works for new projects, performance and compliance of operating assets including control and protection upgrades for the East Kimberley Power System. She combines this with a broad practical knowledge of the power system, synchronous generation, wind and solar power plants.

Peer Review and Editorial Advice

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Bruce Miller is an experienced Principal Consultant, experienced in providing detailed, and high level, technical solutions to both government and private clients from around the world. He has over 30 years' experience in power system analysis and is the leader for the Melbourne based power system study team.

- Commercial/Technical studies relating to the interaction of commercial and technical issues associated with Electricity markets
- Computer simulation and analysis of complex power transmission and distribution systems
- Energy and Power Modelling
- HVDC, SVC, Statcom and Power Electronics
- Modelling Railway Power Traction systems
- Power Station Design
- Power Station Commissioning
- Project Management and Engineering
- Software Application development
- Substation Design

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[i] CIGRE WG C5.06 TB 435: Ancillary Services: an overview of International Practices
[ii] NECA Review of Market Ancillary Services - Final Report June 2004 page 7
[iii] NEMMCO Ancillary Service Review – Recommendations Final Report 15 Oct 1999 page ii
[iv] AEMO: 2016-10 Frequency Monitoring - Three Year Historical Trends.pdf page 7
[v] Reliability Panel Frequency Operating Standards Determination September 2001 page 5
[vi] AEMO Future Power System Security Program. P 19
[vii] AEMO Integrated Third Report SA Black System 28 September 2016 page 42, and footnote 44 and p 80 footnote 75
[viii] AER CSE Enforceable Undertaking
[ix] See AEMO Power System event report for 1 November 2015
[x] PJM Manual 14D Generator Operational Requirements section 7.1.1
[xi] UK Grid Code: Connection Conditions CC.6.3.7 (c) (ii) and (iii)