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Chair, Australian Energy Market Commission
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31 October 2019

(Lodged electronically)
Attention: Ben Hiron

AEMC Primary Frequency Response Rule Changes (Ref. ERC0274, ERC0263 and ERC0277) Consultation Paper 19 September 2019

Delta Electricity operates the Vales Point Power Station situated at the southern end of Lake Macquarie in NSW. The power station consists of two 660MW conventional coal-fired steam turbo-generators. Delta Electricity appreciates the opportunity to comment on the proposed rule changes.

Delta Electricity does not support the proposed rule changes. Knowledge of the present state of frequency performance from records collected at Vales Point, combined with detailed understanding of how steam-fired turbo-generators provide frequency support, lead us to conclude that a market-based solution is possible and is a superior solution to the mandatory procurement approach proposed in these rule changes. Delta respects the experience and knowledge of the proponents but considers that neither has arrived at their proposed solutions after a rigorous analysis of all that has changed in the NEM to produce the observed deterioration of frequency control or a thorough understanding of the impact of the proposed changes on the NEM and its participants. Delta would like to see the AEMC undertake these pieces of work in conjunction with AEMO prior to implementing any mandatory service provision.

If the current market arrangements are demonstrated by adequate, reliable data and steadfast conclusions to present a material risk to system security, Delta Electricity supports temporary direct action that limits the risk. Delta understands that groups of synchronous generators are willing to offer and put in place arrangements to operate large generation capacity with tighter primary frequency response (PFR) deadband control in order to mitigate a real risk to system security and permit more time for the development of a more appropriate solution. It is Delta's view that this more permanent solution should be market-based so that the most efficient outcomes from relevant service providers are procured at least cost and so that innovation is encouraged. If measures to mandate PFR are urgently required to mitigate system security risks, Delta also recommends they have a limited duration, more appropriately set deadbands that consider Australian experience and plant specifications associated with pre-NEM regional standards, and that the interim measures are removed once a market solution has been developed.

Delta does not accept that the observed deterioration in frequency outcomes is primarily caused by deliberate removal by participants of PFR or, at least, daily performance records that demonstrate dates and times when PFR reduction contributed to trended deterioration have not been produced. The single most significant factor that appears to correlate to daily fluctuations in performance is the percentage dispatch, relative to total generation, of intermittent generation capacity. Charts in Attachment 3 are provided for information to support this observation. AEMO's own assessment of Regulation FCAS Contribution Factors, utilised to apportion expenses for the Regulation FCAS services, demonstrate that Intermittent Generation produces five times more causation per MW of installed capacity than conventional generation. When tracking daily records of frequency event counts outside the normal operating frequency band (NOFB) and time outside the NOFB, there appears to be a correlation of daily performance with the percentage dispatch of intermittent generation.

Delta is concerned that the AEMO proposal will disincentivise some participants from closely following dispatch targets due to the distortion in causer-pays calculations. Delta considers that as a result the AEMO mandatory PFR proposal, and the specific exclusion of stored energy headroom, potentially represents a greater risk to system security than currently exists.

Delta has been participating in discussions of frequency control through AEMO's ancillary services technical advisory group and frequency control working group and derived significant value from the exchange of ideas that they facilitated. Unfortunately, these groups have met less frequently in 2019 than in the two preceding years. An unintended consequence of less frequent meetings is a wider disconnect in participant viewpoints and understanding of the issues relating to frequency control. This is particularly true of the significant contributory factors to frequency variation besides locally delivered primary frequency control. Delta encourages the AEMC and AEMO to reestablish processes that facilitate more regular discussion and that seek collaboration in developing market solutions to controlling frequency variations.

Delta Electricity strongly supports market solutions to frequency control issues. Any market solution must appropriately recognise the full cost of providing stored energy headroom and its necessity in providing both PFR raise services and the existing Fast FCAS (6s) service. This would provide the most efficient, effective, fair and appropriate solution that supports the NEO and incentivises investors and participants to innovate new solutions as further conventional providers retire during the continued transition to a reduced carbon future. In Attachment 4, Delta Electricity offers an example road-map towards an alternative solution that Delta Electricity considers could deliver a market solution adequately preparing for the required stored energy headroom and encourage new entrants in the provision of PFR. Delta interprets the reduced level of consultations in 2019 as indicative of reluctance by the market operator to consider, facilitate and cooperate with market participants in the development of a market-based solution as a first-choice measure but hopes this interpretation is incorrect. Only after reasonable efforts to develop and implement a market-based solution are demonstrated by market events and data to be unable to meet appropriate control standards would Delta Electricity support a mandatory solution with such a tight deadband of control as proposed.

To discuss this submission and any issues that it raises, please contact Simon Bolt on (02) 4352 6315 or simon.bolt@de.com.au.

Yours sincerely

Simon Bolt

Simon Bolt
Marketing – Technical Compliance

Attachments:

1. **PFR Rule Change Discussion**
2. **AEMC Consultation Questions – Delta Electricity answers**
3. **Charts of Significant Causation of Frequency Instability outside FOS NOFB apparently correlating to Intermittent Generation Dispatch percentages**
4. **Road Map (example) to a Market Solution**

Attachment 1 – PFR Rule Changes Discussion

Introduction

In 2001, +/- 150mHz variation in frequency maintained 99% of the time statistically deviating in a standard bell-shaped distribution around 50Hz, with no required tighter definition for any other period of time, was considered accurate by the system operator to be representative of a nominal 50Hz. AEMO no longer believes this to be the case and argues that, statistically, frequency is found less often at 50Hz than was the case previously, yet still inside the NOFB 99% of the time. Presumably, AEMO now believes variations of +/- 150mHz, or at least less time found precisely at or near 50Hz on some previously unspecified tighter deadband, is no longer providing accuracy for them to allow for adequate predictions of system behavior and the possible impacts on system security from poor behaviour. The question of quality of frequency performance ought to be one that has calculated engineering risks associated with it and these risks ought to be central to the FOS.

Recent History

Delta Electricity has compiled significant frequency performance data over the last decade, including counts of frequency outside the Normal Operating Frequency Band (NOFB), frequency histogram performance and other factors relevant to the Frequency Operating Standards (FOS). Whilst frequency performance has noticeably extended more often towards the extremities of the FOS NOFB, this is the determined standard participants are engaged to meet and no consequences in power station plant performance are obvious to Delta Electricity either in operational difficulties or operational costs as a result of the present frequency conditions.

Over 2018/19 and in recent previous years, frequency control in the NEM was noticeably trending towards a breach in the defined expectations of the FOS for operating time within the NOFB. What has not been clear is whether or not the trends represent real risks to system security. However, it is understood that AEMO believes the risk to be real and that prudence would require this risk to be mitigated. It is also clear that over the last two quarters actions by AEMO increasing Regulation FCAS volumes and adjusting load relief assumptions have stabilised the frequency trends and prevented a breach of the FOS. Charts presenting this information are provided in Attachment 3. This would seem to represent a level of adequacy in the existing controls at AEMOs disposal.

It is considered to be a recent development (over 2019) in the monitoring of frequency performance that AEMO and consulted experts have become concerned about the oscillatory nature frequency information sometimes displayed in data records for levels inside the NOFB. AEMO believes these observations are evidence of uncontrolled frequency movements within the NOFB. However, it is also expected that oscillatory frequency fluctuations within a tighter deadband of +-15mHz will also exist.

What is perhaps more important is that for effective control to exist the randomness of movement should be controlled to produce, over appropriate assessment periods, a statistical distribution of records that demonstrate a bell-curve distribution rather than a “table-topped” or a “sharp spike” distribution. “Table-topped” shaped histograms might truly present evidence of lack of control. Spiked distribution would demonstrate inefficient overcontrol inside the NOFB. It is suggested that mandatory deadbands at +-15mHz will result in spiked distribution when presented on the FOS +- 150mHz NOFB. However, tight deadbands without headroom may produce an oddly shaped distribution because lower response will be universally applied while raise response will only be delivered by those enabled to deliver the Fast (6s) FCAS service.

Causes of Frequency Performance Deterioration

In the Rule change proposals, the proponents assert that frequency control has deteriorated primarily due to a reduction in primary frequency control by the large synchronous generators. However, contained in this response[1] is evidence of other significant causation that Delta Electricity believes has equal or greater impact on the present day to day trends. Without fully addressing these other contributing factors, tighter frequency control may only mask and delay an inevitable need to revisit frequency control again in the future after any establishment of tighter frequency deadbands either mandated or market provided.

Reduction in primary frequency response has occurred in five ways in the NEM in order of importance as considered by Delta Electricity:

1. Retirement of conventional synchronous generation.
2. Increasing installed capacity and dispatch of asynchronous generation, with consequential difficulty in predicting minute to minute capability and without inclusion in designs for reserving energy in storage for second to second delivery of raise PFR and, in some cases, no ability to adjust output for frequency changes.
3. Reduction by some participants of stored energy headroom in synchronous generators required for providing rapid second to second raise support.
4. Replacements of mechanical governors on some synchronous generators with computer-controlled devices that have selectable and controllable droop within the NOFB and operated for periods with no governing response within the NOFB
5. Adjustment of deadbands on secondary local controllers of synchronous generators often associated with delivery of FCAS

Scheduled Intermittent Generating sources, by AEMO's own assessments in the published FCAS contribution factors, produce five times causation per MW[1] than synchronous machines. Coupled with this observation, a trend in observed daily event numbers and time outside the NOFB charted alongside percentage intermittent generation in the NEM and NSW demonstrates a correlation in activity. Days with higher events numbers and time outside the NOFB appear to regularly follow changes in percentage dispatch of intermittent generation. The Tasmanian trial performed by AEMO[2] and Hydro TAS also made observations specifically upon wind generation. It appears that large scale solar generation has even greater impact than wind generation. Charts of these observations are included as attachment 3.

Problems with the Rules proposed

Both the AEMO mandatory Rule change and the Rule change proposed by Dr Sokolowski report that the reduction in primary frequency response, in general, is the significant cause of deteriorating frequency conditions but neither Rule change proposal addresses the cause Delta Electricity demonstrates in this response attributable to percentage increase in dispatch of intermittent sources relative to overall dispatch.

Both of the mandatory Rule change proposals have not adequately delved into and subsequently addressed in the proposed solutions the variations in PFR delivery systems that at many power stations consists of a combination of controllers working in coordinated fashion. Successful outcomes depend on equitable and comparable services delivered by competing services. Many stations, such as Vales Pt,

[1]See attachment 3
[2] AEMOs Frequency-Control/Trials/Tasmanian-Frequency-Control-Tests-Summary-Report.pdf pages vi,8,9,16

already the proposed +- 15mHz deadband established on a mechanical governor ready to deliver PFR. However, by design these devices neither monitor electrical frequency nor continuously deliver a MW response until frequency returns to an absolute 50Hz condition. The device monitors turbine speed on a turbine that, coupled to the generator rotor, is some 30 metres in length. The detector, a set of spinning weights, reacts to speed changes to adjust unit output via mechanical hydraulic action in proportion to the speed change detected in accordance with the mechanical droop lever ratio (commonly 4%). If the system frequency stabilises to a value other than 50Hz after this immediate reactionary response, this controller has completed its purpose. A secondary controller of a completely separate controller monitors an instrument that delivers a representation of electrical frequency as experienced on the generator and provides the FCAS service delivery the MASS requires. This coordinated DCS and mechanical governor system is largely unchanged since market start except for the deadband on the DCS portion which is now matching that required by the FOS and the AEMO MASS specifications whilst the mechanical controller deadband remains unaltered do to the complexity of doing so. It is easier, but more expensive, to replace it completely which some stations have done. Accordingly, some stations will have a third or more controllers all trying to coordinate the overall reaction of a single Unit. If the various different systems are not detecting and controlling to the same feedback of frequency, it will not be expected that when set to similar deadbands, the controls will be coordinated. NSW has never had deadbands on local power station secondary PFR controllers set to any lower than a 50mHz deadband. Assignment of deadbands to levels lower than 50mHz in NSW is expected to warrant the introduction of further “grandfathering” interim provisions if imposed upon machines unaltered since market commencement as these machines may not be able to obtain appropriate support from original equipment manufacturers (OEMs) for the tight control or adequate insurance against damage if the control has such impacts.

Neither of the two proposed mandatory Rules, propose to address the loss of stored energy headroom. In contrast, AEMOs proposed Rule and its associated PFR Requirements (PFRR) will potentially further reduce the headroom that is still provided by some NEM participants even when not enabled in the Contingency FCAS markets[3]. It is this potential for further reduction in headroom that represents a risk that a greater system security condition will arise if the proposed Rules are implemented unaltered.

There appears to be a contradiction between AEMO’s assertion that mandatory primary frequency control is urgently required to address a growing system security risk and its solution which specifically excludes mandating the preparation of stored energy (headroom). With no fast-delivery stored energy mandated in the PFR rule and its supporting PFRR, the initial PFR raise operation in the NEM will make demands only on the 6s contingency FCAS market providers instead of on all generating units. If the 6s market ancillary service dispatch represents the stored energy source providing the PFR raise effort, the Rule change represents a distortion of the fast raise market service. Units with no headroom will, eventually, after raising more slowly produced energy to provide raise support, respond in PFR support but, if this energy is not prearranged as stored energy ready for rapid delivery, the delayed response can be as long as several minutes and be inappropriately timed to provide effective PFR. In the meantime, the stored energy for 6s FCAS will be utilised by PFR and if later needed will result in a less effective contingency response. Hence, by not mandating stored energy in its PFRR as support for its proposed Rule change, the AEMO solution is not mandating raise responses from all Units but, instead, only from enabled 6s FCAS providers and subsequently weakening the 6s FCAS delivery. If a market service will actually be the only service providing the raise support, modifying the market services to recognise this expectation and prepare equations to secure sufficient stored energy headroom from a modified market process is a better solution.

[3] Contingency FCAS markets are currently the only way stored energy ready for fast Frequency response is acquired. Some participants still maintain headroom when not enabled to provide contingency FCAS but tighter deadbands will provide an incentive to minimise headroom if it is not required or otherwise such Units risk being more erratic in normal energy dispatch due to an increase in delivery of rapid primary frequency response.

The AEMO proposed Rule to incentivise participants (ERC 0263) by reducing to zero the FCAS contribution factor in return for the provision of tighter deadband control will disrupt the purpose of compiling FCAS Contribution factors (formally known as "causer pays" information). Generators with tight deadbands without stored energy headroom to rapidly provide raise services and those that have plant conditions and more inaccurate predictive outputs and which therefore regularly cause the need for frequency support from others, will, after engaging some form of tighter deadband frequency control, no longer be adequately monitored for causation or compensating the market for actual lack of response, off target performance or unit interruptions. This Rule change, if adopted, will render the contribution factor redundant. If the causation factors no longer capture causation from all participants, they become inappropriate in application and should be withdrawn. The Regulation FCAS market expense settlements process should then revert to Generator/Customer assignments applied for the settlements of Contingency services expenses. Whilst Delta Electricity might benefit from the change as proposed in that it might avoid significant expenses in the Regulation FCAS market, the market will no longer be obtaining payment from all causing Units and will therefore not provide the proper incentives to exposed participants.

Alternative Solutions

To support the National Electricity Objective, the required level of frequency control should be:

- Defined by standards proposed and determined by the AEMC Reliability Panel;
- Implemented in the first instance by clearly specified market services designed to be technically capable without being economically unreasonable;
- Subjected to rigorous routine performance monitoring and reporting; and
- Subjected to mandated security controls upon all Units after exhausting possible market solutions. Evidence for this requirement would be demonstrated by detailed performance trends, including measured impacts of market adjustments and operating conditions upon frequency performance.

Standards

It is Delta Electricity's view that the AEMC Reliability Panel, through consultation with all stakeholders, should determine the quality of frequency control that is appropriate in the NEM and that it should be documented as an amendment to the Frequency Operating Standard. If further quality of frequency control is required within the NOFB, without which a system security concern is considered by AEMO and agreed by the AEMC to exist currently, then Delta Electricity considers the FOS requires amendments to fully document the nature of a required standard and the engineering reasoning for its requirement. Stakeholder consultation processes are crucial to the success of these amendments.

While comparisons with other energy markets are useful, the uniqueness of the Australian NEM and the process of consulting on the technical and economic impacts of such quality of control, should deliver a standard of quality that more adequately balances technical and economic outcomes than may be the case in other markets not similarly designed, motivated and considerate of reasonable viewpoints from stakeholders.

In recent years, the AEMC and the Reliability Panel have separately reviewed the FOS and the AEMC has signaled that there may be further reexamination of them as further transition towards renewable energy sources takes place in the NEM. The development of a standard for the quality of frequency control inclusive of rate of change and statistical distribution expectations for operation within the NOFB may be worthwhile considering in future reviews.

Under current market arrangements, if the system frequency is contained within the expected limits of the various categories defined by the FOS, then the system ought to be considered secure. If the nature of the required quality of frequency changes with viewpoints and conditions observed over time, as appears to be the case with the recently observed and reported conditions, it is considered the nature of the FOS and the definition of adequate control ought be the subject of a review of the FOS.

Clearly Specified and Economically Appropriate Market Services

It is also Delta Electricity's view that, underpinned by defined standards, appropriately designed market services coupled with a more rigorous compliance framework for service delivery, can provide adequate quality of frequency control. The present Market Ancillary Service Specification (MASS) remains in further need of revision or, after considering the PFR requirements, a complete rewrite to more appropriately design regulating FCAS services to include for the required primary frequency response as an alternative to the mandatory provision of PFR by all Generating Units.

Following the development of an appropriate standard for frequency control and the quality of frequency, a further MASS review to design market solutions is recommended.

In highlighting the path of a possible alternate strategy to Mandatory Rule changes, Delta Electricity includes Attachment 4, an outline of a roadmap (example) towards a market solution.

Rigorous Routine Performance Monitoring

Performance of any system is best demonstrated by rigorous observation of data and comparison to required outcomes as derived from the defined standards of expected delivery.

Recently, the AEMC Consultation and Determination of the separate AEMO and AER Monitoring and Reporting Frequency Control Frameworks determined new requirements for monitoring of frequency conditions both technical and economic. It is suggested that an appropriate market solution for PFR delivery or even the mandated solutions, if implemented, be also considered for additional performance reporting from AEMO to include for transparency of applied frequency deadbands, droop settings, response times, stored energy headroom at all locations categorised to display the more effective support delivered vs the less effective support.

Mandated Provisions to avert System Security Concerns

Delta Electricity acknowledges a possible temporary need to consider some level of tightening of deadbands of frequency controllers to avert a material system security threat. However, following the time it may take to develop new standards, new market system designs and implement redesigned market services, any interim solution to mitigate a security risk should be replaced by a market solution. A mandatory but far wider deadband than proposed in the Rule changes remains a possible consideration as part of an eventual solution. A wider deadband of control mandatorily applied to all participants provides a safety net when conditions arise, as they can unexpectedly, that unplanned conditions produce inadequacy in systems necessarily designed for more predictable conditions.

Delta Electricity and other participants acknowledged these concerns about security from AEMO over twelve months ago and, following trials in Tasmania, was working with AEMO towards improvements made by multiple activities including the planning of a trial of tighter control on mainland Australia. It is unfortunate that this work was abandoned by AEMO. It is not clear why, in the year or more since these plans were being discussed in a more regular and effective consultative fashion, the system security concerns have been left unchecked except for the mandatory Rule change proposals and some FCAS market adjustments.

With AEMO support and coordination, mainland trials of tighter deadbands could have already been completed and reports published demonstrating to the market effective minimum levels of PFR required for efficient PFR control in a market environment. Delta remains supportive of this work being undertaken.

Market delivery systems could also be modified by AEMO to assist in more appropriate reactions to multiple contingency events like that of 25 August 2019. Systems that either maintain regional minimum delivery of contingency FCAS services or more promptly react to interconnection interruptions to assign regional services for an islanded region remain worthwhile of further considerations for AEMO in frequency control responses of relevance to system security risks.

Concluding Remarks

Delta Electricity remains optimistic that an appropriate market solution can be developed and supports an interim solution if an appropriate defined timeline is implemented. We look forward to working with the AEMC and AEMO to help develop a world leading solution for a competitive market producing stable and reliable electricity.

ATTACHMENT 1 – AEMC Consultation Questions – Delta Electricity answers

	AEMC Question	Delta Electricity Comments
Question 1 – ISSUES RAISED BY AEMO IN ITS RULE CHANGE REQUEST, *MANDATORY PRIMARY FREQUENCY RESPONSE*		
•	What are stakeholders' views on the issues raised by the AEMO in its rule change request, *Mandatory primary frequency response*?	AEMO's issues focus on high risk scenarios and claim Market Ancillary services cannot deliver a solution. Delta agrees that the existing design of the MASS cannot deliver what is required. Delta considers that a redesigned MASS can deliver a more efficient solution than mandated Rules. The MASS can easily be redesigned to provide what is required as should be defined by an market determined standard of reliability, quality and precision then specified appropriately in AEMOs MASS to guide engineers of participants and new entrants to build marketable solutions that will deliver the standards.
•	Do stakeholders agree with AEMO's assessment that regulatory change is required as a matter of urgency to restore effective frequency control in the NEM?	Some urgency exists to improve frequency performance but not to a level that requires mandated, not market-designed, solutions from regulatory change. The emphasis on mandated solutions over designed market solutions during 2019 has caused significant delay and distraction from running market trials, discussing more appropriate and efficient market solutions and then designing for them. Determining a mandated outcome will set a precedent for proposals made by the operator which, contrary to its own mission and values to "partner with others to explore, test and learn" and "lead the **design** of Australia's future energy system", demonstrate it prefers to propose mandated solutions and avoids adequately discussing more efficient market solutions.

	AEMC Question	Delta Electricity Comments
•	What are stakeholders views on AEMO's definition of effective frequency control as requiring narrow band frequency response from as large a portion of the generation fleet as is practical?	Delta Electricity considers the proposed approach to be approaching a "gold-plating" mindset without adequate exploring the efficiency that an appropriately designed and delivered market can offer. The required standard of adequate frequency control, considered satisfactory to the market, should be determined by consultation. Once the standard of quality is agreed on, the market services required to deliver the standard, can be specified in a revision to AEMOs MASS. The current MASS services, after recent adjustments to dispatch requirements by AEMO, continue to meet the FOS. It is important that these adjustments, and the assumptions that underpin them, be regularly reviewed by AEMO. Delta's view is that the MASS could be redesigned to include PFR.
•	Are there any other related issues or concerns that stakeholder have in relation to frequency control during normal operation and following contingency events?	The level of intermittent generation and the differing levels of unspecified PFR currently being provided from competing participants reflects the inadequacy of the original MASS design that did not correctly articulate how PFR is secured and how costly it is to secure adequate stored energy to deliver continuous raise PFR. Appropriately breaking down the present delivery of PFR into the various systems that still provide it and categorising and prioritising each of the components to assign value separately to stored energy, electronic vs mechanical governor flexibilities AND tighter deadbands on frequency response will help design better solutions. AEMO was

	AEMC Question	Delta Electricity Comments
		asked to produce this table of systems in the installed fleet in 2018 to provide greater transparency on what is out there. The proposed Rules will make this situation worse if stored energy headroom reserved for rapid raise response is not included for and compensated for in the final market solution.

Question 2 – ISSUES RAISED BY DR SOKOLOWSKI IN HIS RULE CHANGE REQUEST, *PRIMARY FREQUENCY RESPONSE REQUIREMENT*		
•	What are stakeholders' views on the issues raised by Dr Sokolowski in his rule change request, *Primary frequency response requirement*?	Dr Sokolowski's issues appear to focus on market signals and synchronous machine reactions and ignore the impact that intermittent machines and roof top solar inverters are clearly having. Dr Sokolowski infers a system with wide frequency bounds will produce a negative economic impact. In the 18 years of wider NOFB in the FOS, there is little evidence to support this claim. Delta Electricity and most power companies have decades of O&M records and there is no identifiable cost increase. Dr Sokolowski claims that the engagement and disengagement of controllers adds to uncertainty about how the power system will react. Delta's view is that uncertainty is the result of inadequate objectives, assumptions and constraints used to guide market dispatch and maintain system security inclusive of the dynamic MASS requirements (inclusive of a future MASS PFR – a possible alternate solution to mandatory Rules).
•	Are there any other related issues or concerns that stakeholder have in relation to frequency control during normal operation and following contingency events?	The level of intermittent generation and various now differing levels of PFR from competing participants reflects the inadequacy of the original MASS design that did not correctly articulate how PFR is secured and how costly it is to participants to maintain the stored energy required for adequate and rapidly delivered raise PFR. The proposed Rules will make this situation worse if stored energy headroom reserved for rapid raise response is not included in the determined Rule.

Question 3 – ISSUES RAISED BY AEMO IN ITS RULE CHANGE REQUEST, *REMOVAL OF DISINCENTIVES TO PRIMARY FREQUENCY RESPONSE*		
•	What are stakeholders' views on the issues raised by the AEMO in its rule change request, *Removal of disincentives to primary frequency response*?	The main disincentive to tighter primary frequency response was removed by AEMO in December 2018. This related to how the AEMO FI control factor, the mathematical sign of which determines whether raise or lower regulation service is being dispatched by AEMO, is often out of phase with the action provided by mechanical governing systems that remain set with tight deadbands similar to +-15mHz. Therefore the disincentive that motivated some participants to reduce some PFR to avoid such misalignment has already been removed.
•	Are there any other related issues or disincentives in the NER to the provision of PFR, that the AEMC should consider?	A significant disincentive, unaddressed in this proposed Rule changes, is the cost of maintaining additional stored energy when not dispatched to deliver energy or a market service. Prior to market start, NSW synchronous units maintained continuously 10% additional steam energy to deliver the PFR raise objectives with a NOFB at +-50mHz. This stored energy reserve to deliver rapid raise support costs $1M p.a. per 660MW Unit in fuel costs alone. Not adequately compensating a Unit to provide raise PFR through a market process is unsustainable. As intermittent sources produce more causation per installed MW and have not been required in design to provide stored energy for PFR raise responses, it is unreasonable for a synchronous generator to maintain stored energy to adjust frequency without being compensated by a market service to do so.

Question 4 – CAPABILITY OF GENERATION PLANT AND THE IMPLEMENTATION PROCESS FOR AEMO'S PROPOSED MANDATORY PFR REQUIREMENT		
•	For stakeholders who own and operate scheduled or semi-scheduled generation plant: How easily can your plant meet the requirements of AEMO's draft PFRR? What, if any, adjustments or investments would need to be made and what are the expected costs?	Not easily for units with mechanical governors. More easily for the DCS secondary controls to adjust to +/-50mHz but there is no experience in NSW lower than that suggesting engineering caution in moving any tighter. The Mechanical governor responds to similar deadbands specified in the PFRR but, unlike the expected performance, **does not correct frequency to an absolute value**. A replacement governor (~$4M per Unit), or specific exemptions to the PFRR, is required for the turbine throttling and MW delivery process to function as specified in the PFRR. The DCS controller can be reasonably easily adjusted but the NSW experience has not explored settings of +/-15mHz on these systems and, without suitable engineering reports considering all risks from overly ambitious tightening outcomes, it is considered reckless to approach any tighter than +/-50mHz on the DCS secondary controllers of NSW systems.
•	Do stakeholder agree with AEMO's proposed allocation of requirements between the NER and the PFRR under its proposed rule?	If mandatory deadbands are to be implemented, the headroom provisions as drafted in the PFRR should be included in the Rules and not left to an AEMO process alone. It is expected that headroom specification in the PFRR, if implemented, will eventually require revision and Delta Electricity prefers a market solution and Rules, if required, be found to include deadband and stored energy headroom outcomes in order for PFR to be sufficient and headroom not simply left to AEMO to adjust for in a future AEMO-determined PFRR revision. Stored energy headroom is considered to be required for effective raise

		PFR and, as preparation of it costs around $1M per year per 660MW Unit, a market compensation process is recommended to adequately and efficiently procure it.
•	Do stakeholders consider the implementation time frames suggested by AEMO in its draft PFRR to be appropriate? In relation to AEMO proposed self assessment process, is it appropriate for generators >200MW to provide AEMO with a self assessment within 60 business days and generators <200MW to provide AEMO with a self assessment within 120 business days?	The proposed times reflect only the time for which a participant will need to have self-assessment of existing capability completed and do not relate to implementation of final controls. The shorter/longer time-frame for larger/smaller generators actually may be the reverse of what is required to avoid excessive impacts on the system from more condensed period of testing on the larger Units which will move the system around more.
•	Do stakeholders consider there to be a more appropriate approach to coordinating the implementation of a PFR requirement across the generation fleet?	The self-assessment will produce the existing viewpoints from which discussion and negotiation will lead to the ultimate control outcome tailored for each Unit. AEMO is seeking the tightest possible control outcome. Delta Electricity prefers the standard of quality to be defined first, then the MASS redesigned to suit it and then market services procured to establish the required standard at a consistent, fairly assigned deadband as wide as possible to maintain the required standard and with a fairly assigned level of stored energy readiness for raise PFR across the dispatched PFR suppliers.

Question 5 – AEMO'S EXPECTED COSTS AND BENEFITS FOR ITS PROPOSED RULE, *MANDATORY PRIMARY FREQUENCY RESPONSE*		
•	Do stakeholders agree with AEMO's characterisation of the costs and benefits associated with its proposed rule?	The characterisation of costs are reasonable but missing are the costs of inadequately delivered PFR raise. If stored energy headroom is considered necessary in the determination the costs are significant and equate to $1M p.a. per 660MW Unit in fuel alone at current coal rates.
•	What do stakeholders consider to be the immediate and ongoing costs of providing PFR and being compliant with the proposed rules?	Additional utilisation of the reserved energy for greater numbers of smaller raise efforts and additional losses in throttling already reserved energy by additional amounts.
•	Is AEMO's proposed compensation arrangements for plant upgrades necessary and appropriate?	Yes. Stored energy headroom, if also determined to be required, is a significant cost that would need on-going compensation.
•	Do stakeholders consider the proposed rules to be a cost-effective solution to the frequency control issues identified by the proponents?	No. Mandating Rules on all participants when a market solution could deliver a reasonable quality of frequency performance is not the most cost-effective solution. Market solutions compensate successful bidders for the service they provide on an on-going basis and avoid a gold-plated standard not necessarily required for system security. Reasonable amounts of PFR required for the market directly linked to expected market demand can be predicted and prepared for but needs to include for and adequately compensate stored energy headroom.

Question 6 – DR SOKOLOWSKI'S EXPECTED COSTS AND BENEFITS FOR HIS PROPOSED RULE, *PRIMARY FREQUENCY RESPONSE REQUIREMENTS*		
•	Do stakeholders agree with Dr Sokolowski's characterisation of the costs and benefits associated with its proposed rule?	The wear and tear costs from the wider frequency performance experienced over the last 5 years and longer does not support claims that conditions more often closer to NOFB boundaries costs power stations more or less than previous NOFB operation with longer periods closer to 50Hz.
•	What do stakeholders consider to be the immediate and ongoing costs of providing PFR and being compliant with the proposed rules?	Additional utilisation of the reserved energy for greater numbers of smaller raise efforts and additional losses in throttling already reserved energy by additional amounts.
•	Do stakeholders consider the proposed rules to be a cost-effective solution to the frequency control issues identified by the proponents?	No. Mandating Rules on all participants when a market solution could deliver a reasonable quality of frequency performance is not the most cost-effective solution. Market solutions compensate successful bidders for the service they provide on an on-going basis and avoid a gold-plated standard not necessarily required for system security. Reasonable amounts of PFR required for the market directly linked to expected market demand can be predicted and prepared for but needs to include for and adequately compensate stored energy headroom.

Question 7 – AEMO'S PROPOSED RULE, *REMOVAL OF DISINCENTIVES TO PRIMARY FREQUENCY RESPONSE*		
Allocation of regulation service costs — causer pays		
•	Does AEMO's proposed rule adequately address stakeholder concerns in relation to the risks and rewards associated with the voluntary provision of PFR?	The disincentives present in the Rules 4.9.4 and 4.9.8 are addressed adequately. Delta Electricity does not consider disincentives still exist in the FCAS contribution factor process to the voluntary provision of PFR. The disincentives that concerned Delta in the procedure were removed by AEMO in a change to the Regulation FCAS Contribution Factor Procedure v 6.0 published 2 December 2018. The main continuing disincentives to providing voluntary PFR are: • the current control configuration that offers stored energy headroom outside the assigned FCAS controller deadbands, and • the loss of energy preserved for the Raise 6s FCAS market in doing so • the disincentive for supporting without compensation system frequency due to causation from other technology that produces five times more causation per MW and has minimal installed comparable PFR raising capability AEMOs has proposed to address the second dot point in a future MASS amendment.
•	Do stakeholders envisage any unintended consequences as a result of the proposed rule change?	Yes. Permitting people with suitably tight deadbands to avoid FCAS contribution factor assessment will distort the outcomes of the market assigning expenses to remaining assessed causation and away from participants that may, even with tighter deadbands, be significant

		contributors to the need for Regulation FCAS due to plant trips, malfunctions or due to inherent inaccuracy in the dispatch predictions. Those that continue to maintain stored energy for PFR raising, even when not enabled for FCAS services, will carry an increased burden in real fuel costs and dispatch disturbances and may seek to withdraw the remaining free stored energy.
•	Does the causer-pays procedure contain any other potential barriers to the provision of PFR under normal operating conditions?	The procedure's displacement in time between the assessment/determination of a participant's "four-week" applicable factor and the application of the published factor in market settlements in a future four-weeks is a difficult concept to justify as being always reasonable, especially considering the impacts on the factor when Units are removed from service and the application of expenses at a later time when the out of service Unit has returned to service. However, the procedure is an equitable approach across the technology variations and the complexity of the market and Delta supports its continuation. Additionally, as Regulation FCAS dispatch corrects a much slower time-varying frequency signal, it remains questionable that 4s arithmetic used in the off-target assessment is a relevant comparison on the applied dispatch. However, if Regulation FCAS was revised to include a market-based PFR dispatch, then the current 4s arithmetic would become far more relevant in assigning causation and would be more appropriately assigning costs for the PFR required to correct the frequency movements second to second in the NEM.

Frequency response and compliance with dispatch instructions		
•	What are stakeholders' views on AEMO's proposed changes to clauses 4.9.4 and 4.9.8 of the NER to address disincentives to PFR relating to compliance with dispatch instructions?	Delta Electricity supports the changes to 4.9.4 or 4.9.8.
Operating in a frequency response mode		
•	What are stakeholders' views on AEMO's proposed rule to address disincentives to PFR related to the requirements for FCAS provision?	Delta Electricity considers that the proposed Rule to relieve participants from FCAS causation assessment if a tighter deadband is voluntarily adopted will save Delta Electricity some expense impact but produce a distortion in the Contribution Factor process. Delta Electricity does not support this Rule change and prefers a market solution to adequately compensate for effective PFR inclusive of continuous stored energy readiness for raise PFR.
•	Do stakeholders identify there to be any other sections of the NER that may restrict generators from operating in a frequency responsive mode and providing PFR	Units will always have conditions that arise where there is a genuine concern for the Unit security from erratic response to frequency and may seek opportunities at such times, after consulting with AEMO, to deselect tight frequency control. It is hoped that the Rules continue to permit such requests and requirements from time to time.
Question 8 – AEMO'S EXPECTED COSTS AND BENEFITS ASSOCIATED WITH THE PROPOSED RULE, *REMOVAL OF DISINCENTIVES TO PRIMARY FREQUENCY RESPONSE*		
•	What are stakeholders' views on AEMO's estimate of the associated costs and benefits?	A plant that has no capacity to reduce to a minimum stored energy headroom, will face far greater costs than what AEMO claims to be a minor cost by virtue of the service being voluntary. Stored energy headroom costs a Unit $1M p.a. in fuel costs. Tighter governors on Units that maintain stored head room will draw upon this energy many more times a day than the present FOS and NOFB require costing

		significantly more fuel in replacing the stored energy over that currently replacing energy from governor movements.
Question 9 – DR SOKOLOWSKI'S PROPOSED CHANGES TO ADDRESS DISINCENTIVES TO THE PROVISION OF PRIMARY FREQUENCY RESPONSE		
•	What are stakeholders' views on Dr Sokolowski's proposed changes to the NER to address disincentives to PFR?	The incentives relate to hypothetical reduced wear and tear costs and will not be observable as has the increased wear and tear costs not been observable from the time when the FOS NOFB was altered in 2001 to now.
•	Do stakeholders envisage any unintended consequences as a result of the proposed rule change?	It is the **intended consequences** that Dela Electricity consider inefficient for a competitive market supporting the NEO. This inefficiency of service delivery, and hence true real energy costs and economic impacts from oversupply, is an unintended or unconsidered consequence from the proposed Rule. The Rule change proposal is an un-costed technical proposal requesting an uncompensated "gold-plated" service that assigns more service than the FOS requires, and request an "gold-plated" quality of frequency, without adequate information on the actual engineering costs, purposes and economic consequences such quality of control will result in.
Question 10 – AEMO'S RESPONSIBILITY TO MAINTAIN AND IMPROVE POWER SYSTEM SECURITY		
•	Do stakeholders consider there to be value in amending cl 4.3.1 to explicitly refer to AEMO's responsibility to improve, in addition to maintain, power system security?	No.
Question 11 – INERTIA AND INERTIA SUPPORT ARRANGEMENTS IN THE NER		

•	Is the current chapter 10 definition of Inertia appropriate and fit for purpose?	No comment.
•	Do the current arrangements for Inertia support activities adequately allow for Inertia support by way of fast frequency response from inverter connected plant?	No comment.
•	How could the arrangements for Inertia and inertia support activities in the NER be improved to better utilise the capabilities of inverter connected plant?	No comment.
Question 12 – ASSESSMENT FRAMEWORK		
•	Do stakeholders consider that the assessment framework is adequate for considering the PFR rule change requests from AEMO and Dr Sokolowski?	It is understandable that power system security concerns be treated with a priority. Delta Electricity and other market participants have been willing and remain willing to address the security concerns immediately with an interim solution involving PFR acquired on approximately 9000MW of conventional plant to permit a longer determination assessment period and more detailed consultation with the aim of designing an appropriate market solution.
•	Are there any other relevant considerations that should be included in the assessment framework for the PFR rule changes?	It is debatable whether mandatory solutions should ever be proposed in the NEM before market-based solutions are exhausted and proven inadequate. AEMOs own mission and values should be directing it towards always including market design solutions in such Rule Change proposals. The revisions to the MASS, the adjustment to FCAS regulation volumes and the revisions to Load Relief as performed by AEMO reveal more about the real cause of the deterioration in frequency performance than

		the reduction of PFR by participants not being adequately compensated for real fuel costs. Effective PFR inclusive of reserved stored energy headroom ready to rapidly deliver PFR raise needs to be adequately supported by a market process.
Question 13 – TECHNICAL REQUIREMENTS OF EFFECTIVE PRIMARY FREQUENCY RESPONSE		
•	How do stakeholders view the ability of market or regulatory approaches to provide the necessary broad-based frequency response from participants?	A market based approach with effective monitoring and reporting will allocate only the necessary resources, appropriately compensate the competitive bidder for a successful bid and provide for regular monitoring to encourage revision of the volumes required to maintain adequate performance and then, if market solutions are demonstrated by trended statistics to be inadequate, a mandatory solution might be required.
Question 14 – TEMPORAL CONSIDERATIONS		
•	How do stakeholders reconcile the need to address system security with the objective of minimising the long-term costs to consumers?	The system will always be carrying risks that are low probability but carry high consequential impacts. The arguments for mandating PFR is the same argument for testing electrical protection systems for hidden failures more often than once every four years. The system being tested might fail the day after it is tested. The test period is a compromise between probability of failure and what is a reasonable expense for the risk being incurred. It is not possible to totally eliminate a system collapse with mandated PFR, especially if it does not mandate headroom for PFR raises. A market solution can efficiently resolve risk by agreeing up front in the development of the FOS and frequency quality standard as to what the most cost-effective frequency quality

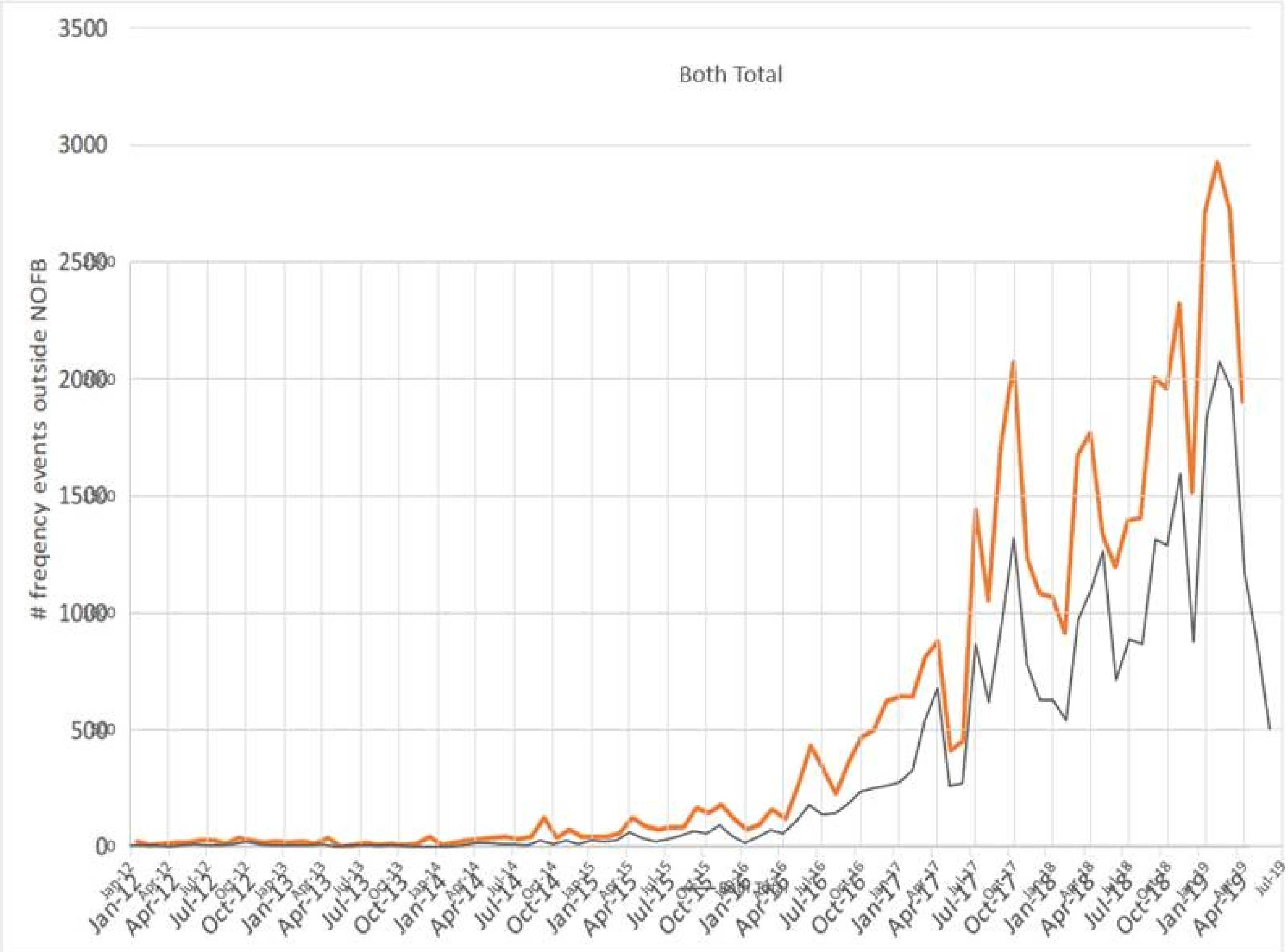
		should be and then procuring only the sources and quantities required from the competitive market to deliver upon that objective. A mandatory service, whilst it simplifies some operator functions and does away with an operator having to perform the complex task of reliably predicting the market dispatch amounts, will result in “gold-plated” quality in exchange because it over employs the available services. The proposed Rules will impact and corrupting existing market FCAS services with unpredictable cost impacts. Costs incurred by participants and not paid for via suitable market services will end up on top of the energy costs and rest ultimately with consumers.
•	Do stakeholders consider the need to address system security in a timely manner as influencing the mechanism adopted to address the issue?	The system security risk relates to low probability circumstances. The frequency is currently meeting the FOS. If a risk of inadequate quality of frequency exists, participants in control of 9,000MW of dispatchable MWs can address the risk via interim trials with temporary tighter deadband controls whilst an appropriate market solution is developed.
•	Do stakeholders consider the process of implementing physical changes to generator governor controls as influencing the choice of mechanism?	The physical changes to governors definitely need to be appropriately coordinated but would be more effectively delivered in small changes building towards a tighter control rather than large steps to +/-15mHz which may or may not be either secure or effective in delivering the required PFR with a stable outcome of the quality required.
Question 14 – CONSIDERING THE COST BENEFIT TRADE-OFF FOR THE PROVISION OF PFR		
•	What is the existing capability of the generation fleet to provide narrow band PFR?	Delta Electricity is aware that there exists at least 9,000MW of installed Generation in the mainland of Australia that is capable but with a variety of capability ranging from tighter deadbands (than +/-150mHz but not +/-15mHz), either no stored energy headroom to around 10% stored

		energy and with variations in droop values on different governing mechanisms.
•	What is the scale and cost of plant upgrades that would be required to meet different PFR performance requirements, including the performance specifications set out in AEMO's draft PFRR?	A suitable market design could make the specifications for the requirements and have participants produce designs and installations with no cost to the market in return for a market that fairly compensates successful competing bids for delivery. The cost of the market will depend heavily on AEMO accurately predicting the amount of service required, the availability of the supply, the reasonable bids for providing the service and the market process at arriving at the amount required in each 5minutes. Another proposal that has not been adequately explored is a redesign of the present FCAS regulation dispatch. Reasonably inexpensive modifications to AEMOs AGC, SCADA databases, Generating Unit interfaces and Unit DCS controllers are envisaged by Delta Electricity to be possible that could see AEMOs central dispatch deliver dispatch quantities to a Unit for rapid PFR response as well as the present time-error correction. Generally, there is less support in the industry for this sort of solution due to widely held viewpoints doubting the reliability and time-precision of AGC dispatch directives to Units even on a 5minute basis let alone the 4s AGC dispatch timeframe. Delta Electricity envisages that a modified dispatch process could deliver FCAS Regulation to a Unit as separate signal to energy dispatch which would permit the Unit controller to receive and process the FCAS quantity directly and more rapidly from stored energy control loops rather than slowly processing it through energy ramping control loops of energy dispatch.

		Also discussed in the ASTAG and FCWG process is the fact that AEMOs current regulation FCAS design does not adequately function during energy ramping periods. This could be improved via a control modification to AEMOs AGC.
•	How much of the fleet must provide narrow band PFR in order to be confident that the immediate system security needs are satisfied?	Prior to NEM commencement, NSW used to run with 10% stored steam energy reserves to meet FOS with a NOFB of +/-50mHz. Of the currently installed Toshiba generators (originally all 660MW rated) plus Liddell in NSW, this equates to a reserve of 12 X 66MW + 4 X 50MW or 992MW. If the NSW market demand is about 10,000MW or less, NSW large generators with suitable stored energy reserved for rapid raise PFR, will produce PFR raise services required to maintain a NOFB of +/-50mHz. Any less raise PFR available and any higher demand, the performance of raise services will deteriorate unless additional service is procured. Similarly, at lower demand levels the performance will be more superior than required. Therefore, a market solution based on market demand procured on a 5minute basis can provide the appropriate market signals to meet an as yet to be determined quality standard dispatching only the reserves required to meet the market conditions.

ATTACHMENT 3 – Charts of Significant Causation of Frequency Instability outside FOS NOFB apparently correlating to Intermittent Generation Dispatch percentages

Delta Electricity maintains records of frequency performance. To validate the Delta data against a known public available source, and with reference to AEMOs charts[4] of the number of frequency events outside the NOFB (Jan 2012 to Apr 2019), Delta Electricity data is overlaid below:



Note that Delta's counts (in black) are consistently less in number per month than AEMOs. The difference is because the Delta count considers sequential 4s intervals where the frequency remains outside the NOFB following a previous 4s period outside the NOFB as a single event whereas AEMOs counts are understood to tally all individual 4s intervals in a day/month. Hence why later charts display both event counts and time measured outside the NOFB. In Delta's measurements of time outside the NOFB contingency events are not excluded.

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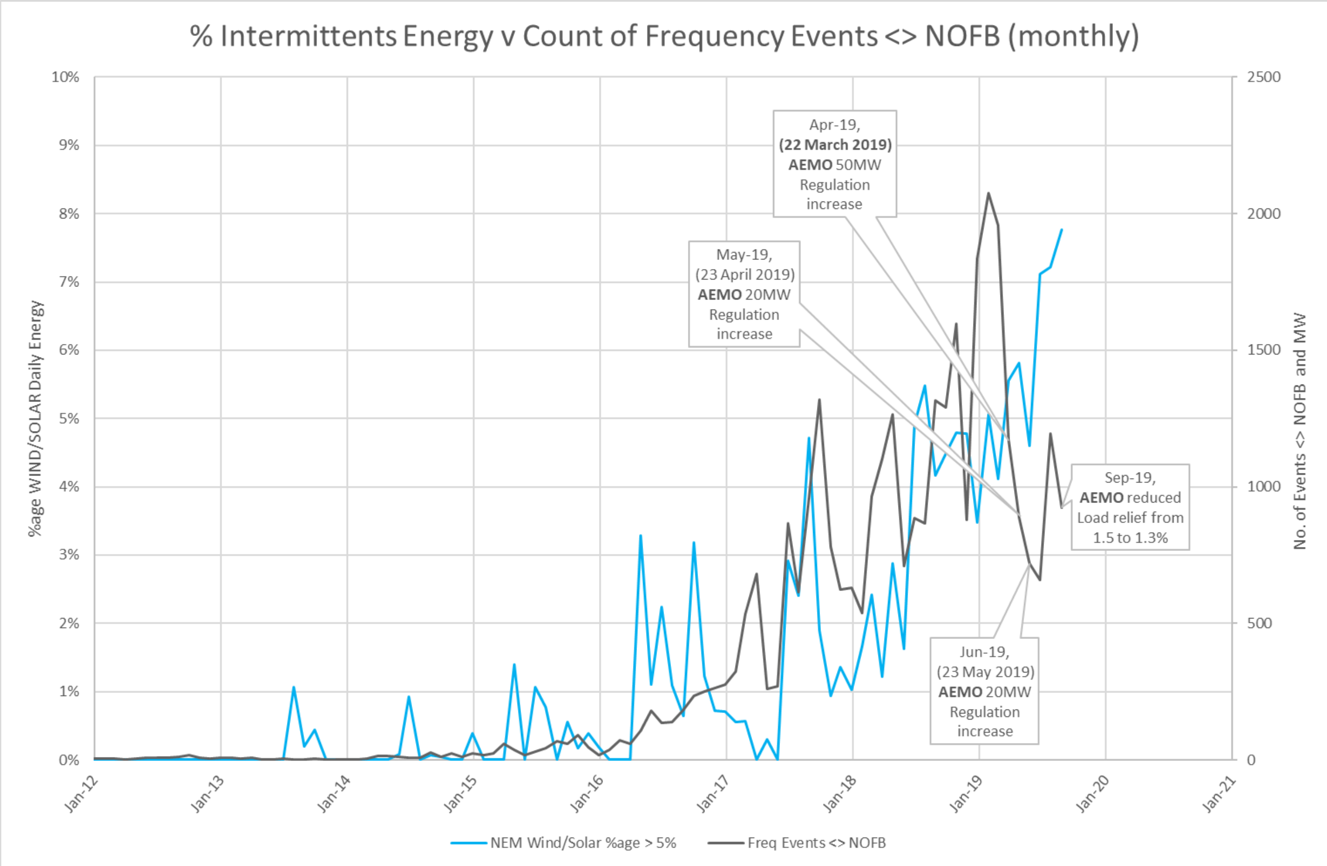
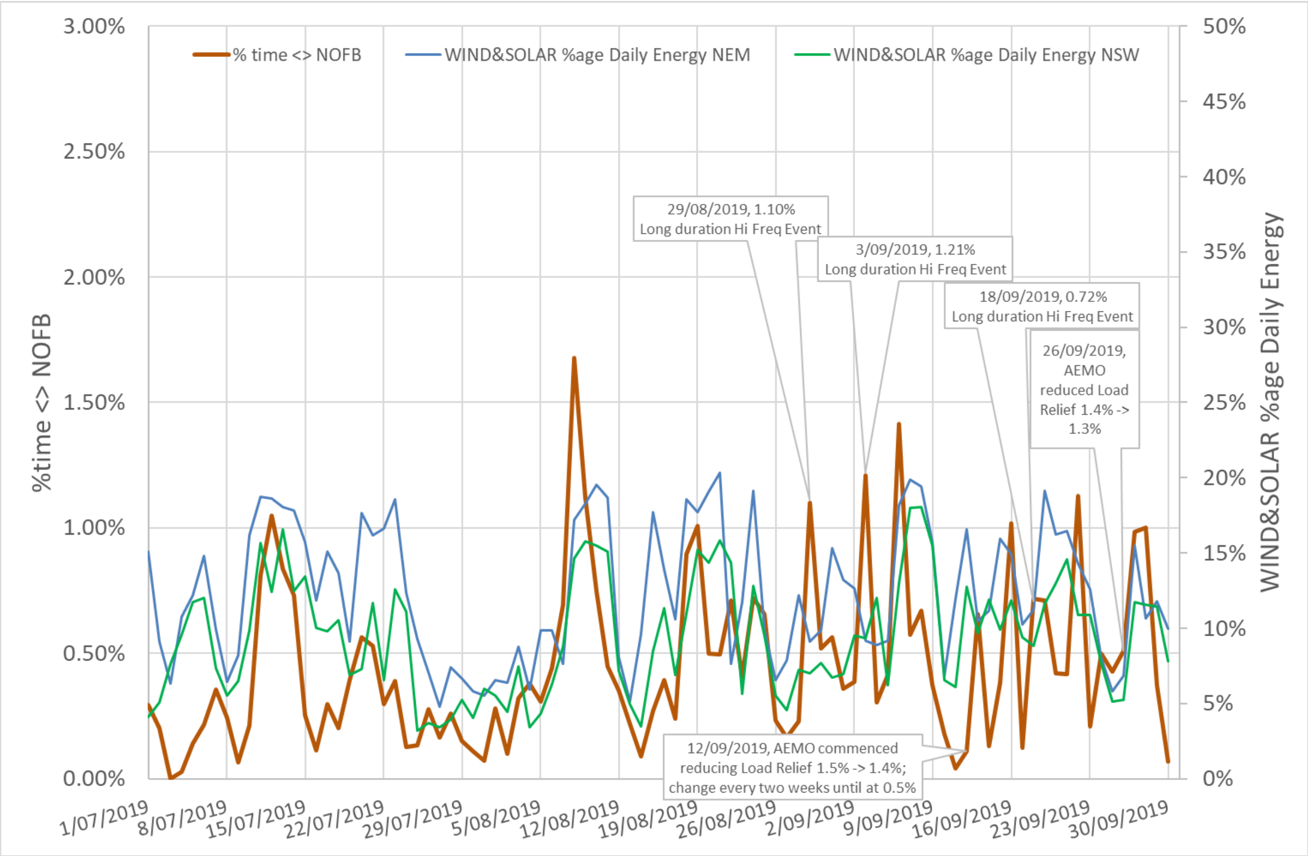
[4] Pg 46 AEMOs Rule change proposal – "Removal if disincentives to the provision of primary frequency control under normal operating conditions"

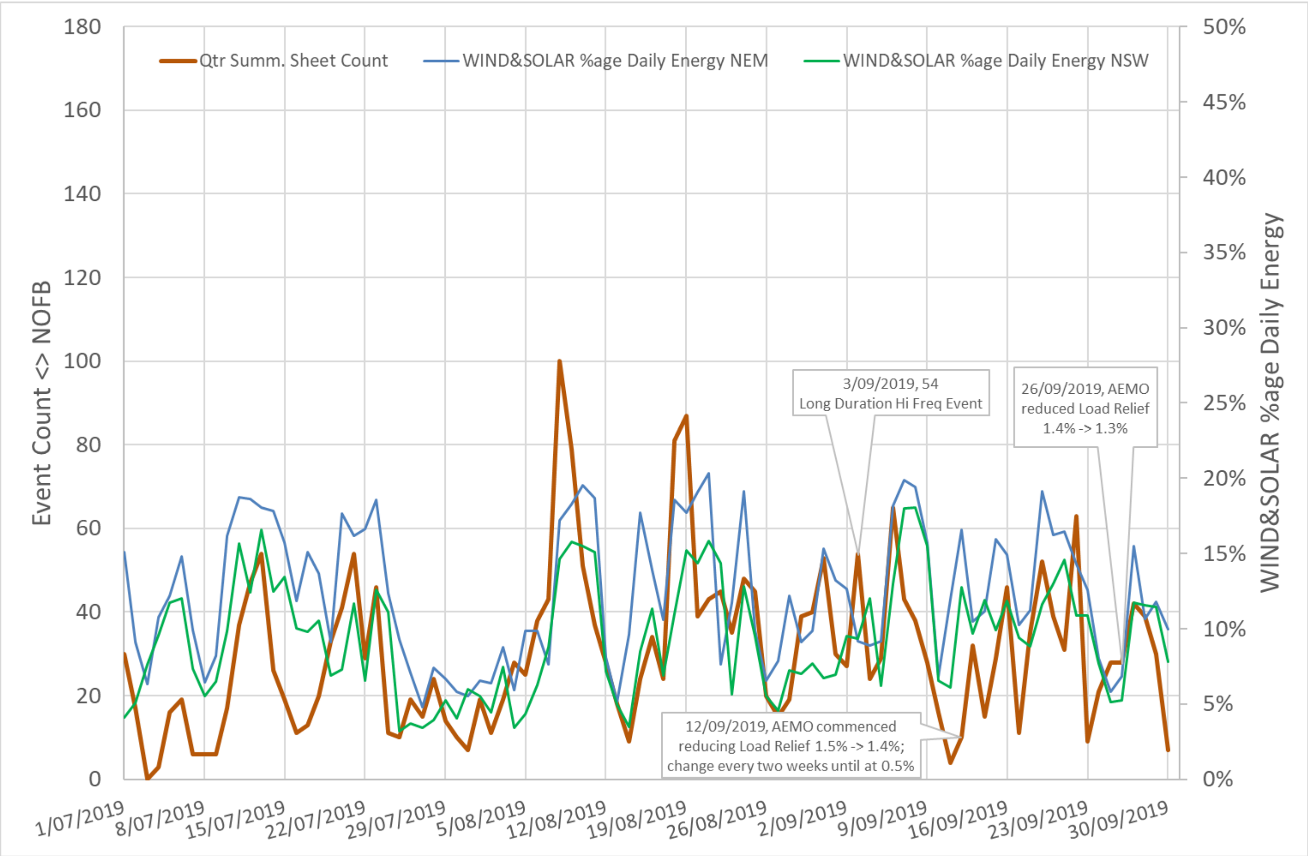
Extending Delta's information to include for Intermittent percentage dispatch the following chart is presented:



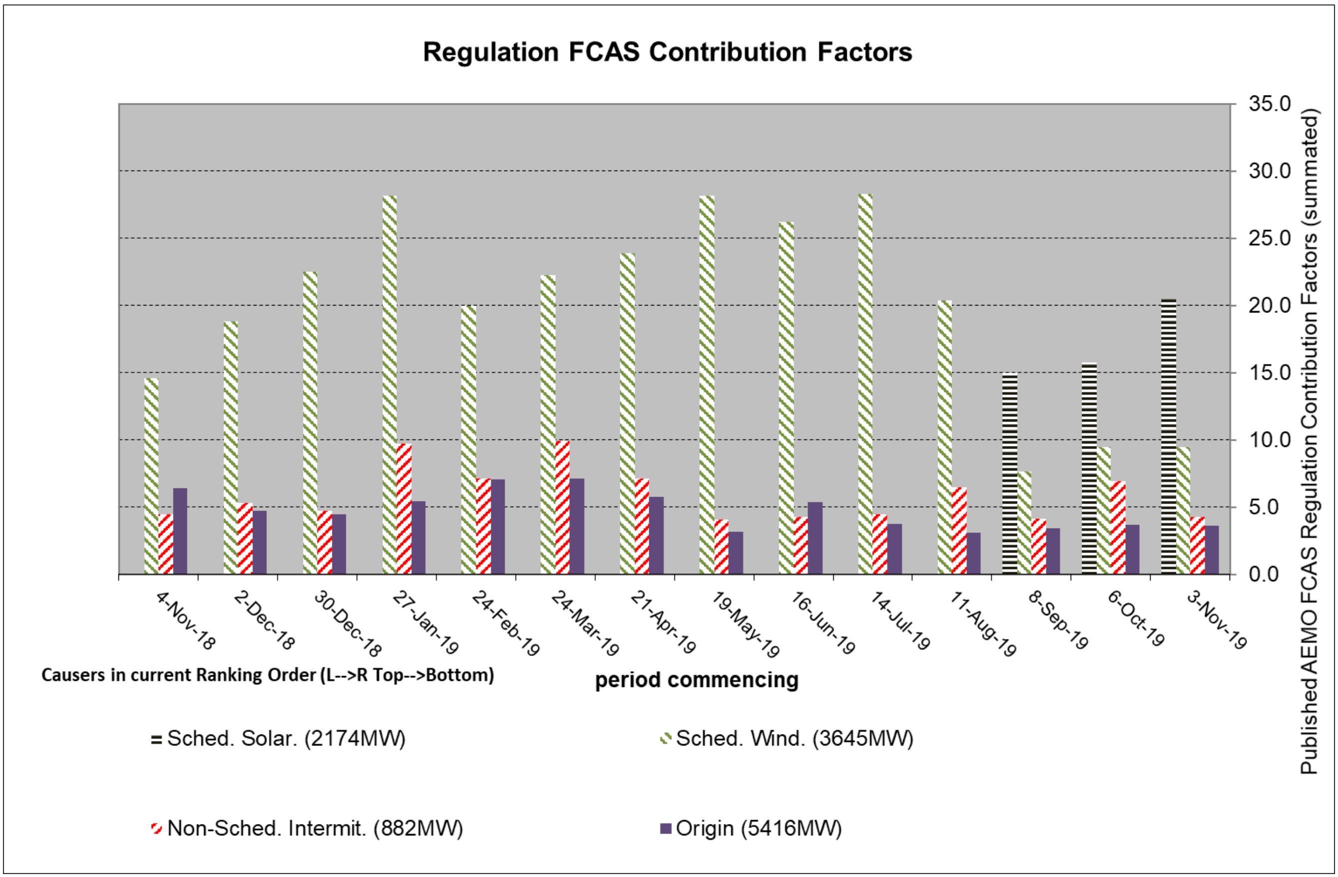
Delta Electricity continues to monitor this correlation and the following two charts present counts of events numbers outside the NOFB and time accumulated outside the NOFB versus the Intermittent percentage dispatch in the NEM and NSW from the July to September quarter 2019. As the monthly tallies don't reflect the variability that is experienced day to day in the assessment, some daily trends follow to display what Delta considers to be a closer correlation in causation than PFR reduction changes which only occurred sporadically on 20-30 machines over the entire eight year period. The lack of a demonstrated trend of deterioration showing a correlation between PFR reductions and the increased event numbers is the major reason Delta does not consider PFR reduction to be the primary cause of deterioration when comparing day-to-day performance.

Daily performance and even hourly performance comparisons potentially highlight variations between scheduled expectations which determine the dispatch objectives and the actual conditions hour to hour and minute to minute. To fully control frequency a more dynamic adjustment to scheduling and dispatch may improve performance as demonstrated by the fact that increased FCAS regulation volumes has been successful in halting the deterioration in event counts.


% time <> NOFB
WIND&SOLAR %age Daily Energy NEM
WIND&SOLAR %age Daily Energy NSW
%time <> NOFB
WIND&SOLAR %age Daily Energy
29/08/2019, 1.10% Long duration Hi Freq Event
3/09/2019, 1.21% Long duration Hi Freq Event
18/09/2019, 0.72% Long duration Hi Freq Event
26/09/2019, AEMO reduced Load Relief 1.4% -> 1.3%
12/09/2019, AEMO commenced reducing Load Relief 1.5% -> 1.4%; change every two weeks until at 0.5%
3.00%
2.50%
2.00%
1.50%
1.00%
0.50%
0.00%
50%
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
1/07/2019
8/07/2019
15/07/2019
22/07/2019
29/07/2019
5/08/2019
12/08/2019
19/08/2019
26/08/2019
2/09/2019
9/09/2019
16/09/2019
23/09/2019
30/09/2019


Qtr Summ. Sheet Count
WIND&SOLAR %age Daily Energy NEM
WIND&SOLAR %age Daily Energy NSW
Event Count <> NOFB
WIND&SOLAR %age Daily Energy
3/09/2019, 54 Long Duration Hi Freq Event
26/09/2019, AEMO reduced Load Relief 1.4% -> 1.3%
12/09/2019, AEMO commenced reducing Load Relief 1.5% -> 1.4%; change every two weeks until at 0.5%
180
160
140
120
100
80
60
40
20
0
50%
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
1/07/2019
8/07/2019
15/07/2019
22/07/2019
29/07/2019
5/08/2019
12/08/2019
19/08/2019
26/08/2019
2/09/2019
9/09/2019
16/09/2019
23/09/2019
30/09/2019

In support of these observations that intermittent generation significantly produces more causation, and hence greater deterioration in frequency conditions, Delta also reports on the following trends in summated AEMO causation factors as published by AEMO and summated in categories.



In this data, prior to 8 Sep 2019, the Scheduled Wind record also includes the Scheduled Solar. These records also do not include for intermittent sources embedded inside the larger participants. Origin's records are presented to display a comparable factor from a comparable installed capacity of more conventional synchronous machines, but some unscheduled and asynchronous capacity also exists in the Origin result.

Generally, derived from this observation, Scheduled intermittents collectively appear to exhibit, at least, five times more causation per installed MW than scheduled synchronous generation. Large scale Solar is providing the bulk of the variation per MW in this analysis. Non-scheduled Intermittents perhaps exhibit seven times more causation. From this comparison, for example, when Intermittent Generation dispatch reaches 10,000MW, it is suggested that it will be resulting in as much causation for Regulation FCAS as that caused by 50,000MW of dispatched conventional generation.

To ignore these trended aspects and perspectives of the observed deterioration in favour of arguments that reduced PFR is the major factor lacks equivalent factual evidence in Delta's opinion. The development of a trend over time of PFR reduction (dates as having occurred on each Unit or on retirement) plotted against reduced frequency performance is recommended to be produced to support further assertions that reduction in PFR has caused the deterioration. Obviously, reductions in PFR will continue to occur in large measured amounts as conventional plant continues to retire and without suitable replacements from new market systems inclusive of stored energy headroom for rapid raise PFR, conditions are predicted to deteriorate further as greater capacities of intermittent sources are dispatched and further capacities of PFR supporting synchronous generation is retired.

ATTACHMENT 4 – Road Map (example) to a Market Solution

An alternative solution

BOP – Balance of Plant

FCAS – Frequency Control Ancillary Service

FOS – Frequency Operating Standard

MASS – Market Ancillary Services Specification (current version)

NOFB – Normal Operating Frequency Band

PFC – Primary frequency control

PFR – Primary frequency response

DCS – Distributed Control System – Conventional digital controller managing coordinated functions of a Generating Unit complete with multiple control loop architecture for Boiler Draft control, Boiler firing, Steam pressure, Feedwater, Cooling water, Turbine, Generator, Generator Transformer, AVR and other BOP.

Background

In NSW prior to market commencement, the ECNSW/Pacific Power expectation for primary frequency control was based on a Normal Operating Frequency Band of +-50mHz.

To deliver the PFR Raise portions represented by this assignment, coal-fired steam boiler turbogenerators were set up to maintain 10% stored steam energy, for rapid provision of frequency raising support. Based on a standard 4% droop lever setting on conventional mechanical-hydraulic governing systems (4% droop representing PMAX movement in the turbine for a 4% change in speed e.g. 2Hz frequency change equates to 660MW power change on a Toshiba 660MW machines), the required stored steam energy to support turbine governor movement in response to a sudden raise requirement was a steam pressure margin over that required for the dispatched MWs.

The 10% headroom, in consideration of droop, catered for a sudden 0.2Hz[5] deviation. e.g. on a 660MW machine 10% stored steam energy could rapidly deliver 66MW via prepared pressure and rapid reaction from the mechanical governor. However, in consideration of the present NOFB, it is conceivable that PFR support is required for the area between AEMOs proposed +-15mHz deadband and the boundaries defined by the NOFB. This equates to 135mHz (150 minus 15mHz) movements and the associated MWs as determined from the droop equation. This assumption, or perhaps 150mHz, could be used as the starting point to define the PFC stored energy specifically required for raise services and the delivery for raise and lower PFC from AEMO dispatch.

[5] Coincidently, 0.2Hz matches the current range trigger from which MASS providers are expected to have captured recordings to monitor Contingency FCAS responses from Units.

A coal fired power station delivering and maintaining 10% stored energy for PFC raise responses experiences significant throttling efficiency losses. The 10% stored energy is known to equate to about 0.9% additional coal consumption. Based on nominal conditions and present coal tonnage costs, this equates to about $1M p.a. per 660MW Unit.

In contrast to PFR Raising, PFR lowering is more easily arranged through throttling but resulting in additional throttling losses (to the losses inherent in maintaining 10% additional steam energy for raise service) across the throttle valves. Mechanical governors cannot be prevented from providing some response even below a Minimum Load otherwise set and maintained by a Unit DCS and the AEMO AGC. However, on electronic governors, the reactions are more controllable and may result in more significant sharp reductions to zero in footroom when operated at minimum load. On all plant at times of light load and dependent on the numbers of in-service Units, footroom capacity depends on boiler furnace flame stability (a safety and plant security risk) and stability in steam drum level control.

Proposed Rule Change Limitations this strategy addresses

- Mandated tight deadbands but no requirement for headroom or footroom – Without headroom and footroom being prepared, maintained and rapidly deliverable, the system security risk raised by AEMO will not be resolved by the proposed Rule changes **and may be worsened**.

- The mandatory solutions in combination with existing MASS design are not adequately compensating participants for the expensive costs for maintaining headroom, footroom. For success in addressing system security needs in the current NEM and providing incentive for new entrants and innovations in the future NEM, a market value for the cost of the stored energy required and additional throttling losses incurred to rapidly address and correct frequency movements must be developed.

Proposed Alternate Strategy

1. Establish interim delivery of tighter deadbands on governing systems of capable large regulation FCAS registered Generators:
    a. Willing AEC members coordinate and act quickly (by December 2019) to establish necessary letters of agreement for participating companies and Units
    b. ACCC and AER acceptance and waivers in place
    c. AEMO approval - The trial should not take place unless AEMO supports it at senior levels and provides a commitment to resolving the issue long term via a market solution as defined below (or similar)
    d. Implement (by mid-December 2019) tighter deadbands via small adjustments and scheduled changes in all regions using existing capability and reserve services.
    e. The trial should have a sunset expiry based on an expected date (suggested by AEMO and AEMC and supported by market participants) by which time a market solution is reasonable considered to have been designed, Rule changes consulted on and determined, installed and commissioned. Otherwise, after exhaustion of possible extension time periods agreed to by each member, the trial will cease.

2. Rule Changes:
    a. Define the Quality of frequency control the NEM requires under Rule 4.4.1(a) – AEMC/RP action
    b. Considering the proposed strategy below, determine whether Rule changes or, more simply, a MASS revision is required.

3. Develop and consult on revisions to the MASS and relevant AEMO operating procedures to include for PFR in the regulation FCAS service:

    a. Regulation Service be re-specified/redesigned to include for Headroom/Footroom and financial payments for the preparation for the quantities offered in all five-minute periods.
    b. Regulation service to be redefined to be inclusive of:
        i. PFC
        ii. Centrally dispatched time-error corrections as currently delivered by AEMO
    c. Regulation FCAS Supply Bids by participants to be made inclusive of:
        i. Raise Regulation offer with separable portions in a single bid quantity that includes
            - PFR raise portion and
            - Central Dispatched Raise regulation offer
        ii. Lower Regulation offer with separable portions in a single bid quantity that includes:
            - PFR lower portion and
            - Central Dispatched lower regulation offer
    d. During pre-dispatch, AEMO should prepare expected market requirements for total Regulation FCAS based on:
        i. Raise PFC – using an equation applied regionally related to the stored energy required to rapidly arrest a 150mHz drop from 50Hz based on a 4% droop response measured against the current regional demand but also with constraints evaluating the available MWs when lower numbers of machines are in service:

            e.g.

            - Based on a NSW demand of 10000MW and standard droop settings, a 4% speed change in NSW will require 10000MW raise service so a 150mHz speed change

(0.3% speed change) would require 750MW of PFC raise delivery **prepared for at all times in stored steam energy ready for rapid response**.

- In NSW, the twelve Toshiba Generators (originally 660MW machines) and Liddell's 4*500MW Units ought to, if all in service and sufficiently clear of PMAX, be able to provide 12*66MW + 4*50MW if the droop control and reserve energy was set to 10% meaning 992MW is the available NSW capacity from the large generation fleet. For a 750MW requirement for 10000MW demand some PFC can be relaxed. The market process that determines successful bids while evaluating required MWs can provide the method of determining the Units that are dispatched.
- If only 8 of the 12 Toshiba Units and no Liddell Units are in service, the available raise PFC assuming 10% stored energy, is only 8*66MW being only 528MW and, assuming at higher demands, the available Units will be dispatched closer to their PMAX meaning on traditional FCAS trapeziums, the available headroom is less.
- Minimum overnight load (or midday load) is around 6000MW reducing the PFR requirement to 450MW

ii. Lower PFC - using an equation applied regionally related the required throttling to match a 150mHz rise from 50Hz based on a 4% droop response measured against the current regional demand but also with constraints evaluating the available MWs when larger numbers of machines remain in service and demand is at minimums.
iii. Current Raise regulation – to match AEMO objectives for slower time-error correction as centrally dispatched
iv. Current Lower regulation – to match AEMO objectives for slower time-error correction as centrally dispatched.

e. For Dispatch, AEMO should prepare Unit Regulation FCAS dispatch to Units with successful bids of:
   i. Raise quantities as an addition of c.i. + iii. quantities above.
   ii. lower Regulation as an addition of c.ii. + iv. quantities above.

   Note: This will significantly, and necessarily, increase Regulation FCAS quantities. The necessity lies in the delivery of fair result accounting for the stored energy costs associated with raise service and sending market signals to other potential suppliers if the supply reduces over time as conventional systems are retired. Lower prices, assuming bids fairly reflect costs for delivery, will remain lower than raise services but mindful of the additional throttling loss and costs this represent to a participant. Regular and longer daily periods of regional minimum demand driving many Units to minimum load operating points will reduce the available lowering service supply which will also send market signals for new entrants.

f. Unit Regulation FCAS action on specific Units –
   i. Raise dispatch will remain a single number but will need separating by the local machine into:
      - PFR raise portion delivered by stored energy percentage and
      - Central Dispatched Raise regulation offer delivered through Energy MW 4s dispatch setpoint signal

Depending on a Unit's reserve energy percentage which, if enabled, must not be allowed to be less than 7.5% stored steam otherwise preparation for the 150mHz reaction is not sufficiently held, a Unit can interpret the Raise Regulation dispatch MWs from AEMO to mean a summation of the PFR plus the conventional Time-error correction adjustment to the MW Dispatch setpoint via SCADA. Knowledge of the applied reserve percentage and PMAX can permit local Unit calculations of the PFR portion separating it off so the expected MW dispatch adjustment portion can be adequately determined for operational purposes.

ii. Lower dispatch will remain a single number but will need separating by the local machine into:
   - PFR lower portion delivered by throttling within the available footroom from Dispatch MWs to PMIN but including on mechanical governor Units a shorter term and lower resultant delivery prior to DCS override holding the Unit to its minimum stable load.
   - Central Dispatched Lower regulation offer delivered through Energy MW 4s dispatch setpoint signal

   Depending on an expected (and adjustable by market notice) the AEMO system wide required for PFR lower of 7.5% for a 150mHz reaction, a Unit can interpret the Lower Regulation dispatch MWs from AEMO to mean a summation of the required PFR lower plus the conventional Time-error correction adjustment to the MW Dispatch setpoint via SCADA. Knowledge of the applied reserve percentage and PMIN can permit local Unit calculations of the PFR portion separating it off so the expected MW dispatch adjustment portion can be adequately determined for operational purposes.

g. Compliance activities by AEMO for
   i. PFR – on enabled Regulation Units – Unannounced annual (or more frequent) random Spot checks of 5minute DI(s) performance on Units enabled for PFR to observe and check PFC was active during the DI.
   ii. Centrally dispatched time-error corrections as currently delivered by AEMO – Enhanced compliance behaviour recommended but the existing MASS provisions can apply if AEMO prefers.

4. Settlements – FCAS contribution factors remain as currently designed and the factor continued to assign costs to Units on the basis of the causation for the services inclusive of PFR and conventional time-error correction.

5. Monitoring and Reporting Frameworks – modification to these frameworks may be required to include for the Frequency quality objectives based on the determined standard (see step 2). Where necessary as a result of detailed trended analysis, directly compared to defined standards, AEMO should issue market notices to adjust where required:

   a. Load Relief percentage – Contingency FCAS volumes affected
   b. Time Error Correction – Dispatched MW FCAS regulation affected
   c. PFC stored energy percentage – Rapid deliverable PFC affected