AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

1 July 2019

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By online submission

Dear John

Removal of disincentives to the provision of primary frequency response under normal operating conditions

As you are aware, AEMO has been working on solutions to arrest the deterioration of frequency performance in the National Electricity Market (**NEM**) for some time.

The decline in frequency performance under normal operating conditions is primarily caused by NEM generators reducing or limiting their provision of primary frequency response (**PFR**), over the past five years in particular. Unless this is reversed, AEMO will have no ability to control power system frequency stably under normal operating conditions.

In an ideal world, AEMO would carry out trials of different quantities of PFR from different locations on the power system to determine the optimal mix, which would then feed into the development of a market mechanism for its procurement, as envisaged by the AEMC in its Final Report on the Frequency Control Frameworks Review.

Frequency performance, however, continues to deteriorate. More recently, AEMO's discussions with participants and industry representatives have indicated that more generators are proposing to alter their plant to further reduce their provision of PFR. It is conceivable that the resulting impact on frequency performance could contribute to cascading failures following a large non-credible contingency event in some operating conditions.

Because of these developments, AEMO submits a rule change proposal with this letter to address some of the causes of the deterioration of frequency performance under normal operating conditions. The proposed changes are capable of implementation before summer 2019-20.

The purpose of this proposal is to remove identified regulatory disincentives for the provision of PFR under normal operating conditions. AEMO requests the AEMC to consider this proposal as a non-controversial rule under section 96 of the NEL.

Queries on the proposal can be directed to James Lindley, Group Manager - Systems Capability, at James.Lindley@aemo.com.au or ☎ 07 3347 3906.

Yours sincerely

Peter Geers
Chief Strategy and Markets Officer

Attachments: Rule Change Proposal: Removal of Disincentives to the provision of Primary Frequency Response under Normal Operating Conditions

ELECTRICITY RULE CHANGE PROPOSAL

REMOVAL OF DISINCENTIVES TO THE PROVISION OF PRIMARY FREQUENCY RESPONSE UNDER NORMAL OPERATING CONDITIONS

1 July 2019

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1. SUMMARY

There has been a clear decline in frequency control under normal operating conditions in the NEM over many years. The main reason for this decline is the action of Generators changing the control settings on their generating systems to reduce the delivery of primary frequency response (PFR) under normal operating conditions.

AEMO is proposing a rule to remove key disincentives in the NER identified by Generators as reasons why they have reduced their delivery of PFR. AEMO considers these changes represent straightforward clarifications that are consistent with the current regulatory intent. They can take effect either immediately or shortly after changes are made to procedures required under the NER. To the extent that Generators subsequently decide to adjust control settings to increase PFR, the proposed rule would help to arrest the decline in frequency control under normal operating conditions.

AEMO requests that this rule change proposal is treated as non-controversial.

2. BACKGROUND

2.1 What is primary frequency response?

PFR is the first stage of frequency control in a power system. It is the response of generating systems and loads to arrest and correct locally detected changes in frequency by changing their active power output or consumption. PFR is automatic; it is not initiated by an external, centralised control system and begins immediately a frequency change beyond a specified level is detected by the responsive plant.

PFR is essential for power system security and is critical following power system disturbances and during power system restoration.

2.2 Frequency control in the NEM

When the NEM was first conceived, it was designed to facilitate interstate trade in electricity produced predominantly by large thermal power stations, enabling excess generation capacity in one region to be efficiently used to accommodate incremental demand in other regions, minimising the total system reserve requirements. For well over a decade of the NEM, this paradigm largely held true.

The market was dominated by large synchronous generating systems, which had typically been arranged to provide PFR continuously, resulting in its widespread provision across the NEM because it was mandatory for most plant[1]. PFR was required outside a frequency deadband[2] specified at no more than ±0.050 Hz (which was half the normal operating frequency band (NOFB) at the time).

In 2001, real-time ancillary services markets for frequency control services were introduced. Eight new market ancillary services were created, commonly referred to as “frequency control ancillary services” (FCAS) – six Contingency FCAS, and two Regulation FCAS.

These market ancillary services are specified in clause 3.11.2(a) of the NER, and AEMO is required by clause 3.11.2(b) to publish a market ancillary service specification (MASS)[3], in which each FCAS is described and performance parameters and other requirements are stipulated. Although they are referred to as ‘frequency control’ ancillary services, they are, in fact, frequency control reserves.

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1 Clause 4.4.2(b) of version 1 of the NER. It is noted that the National Electricity Code, which preceded the NER, also contained clause S5.2.6.4, which specified a narrow deadband for frequency response capability.

2 A deadband is a frequency range that can be specified in a control system, in which no frequency response is given.

3 Available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Market-Ancillary-Service-Specification-V50--effective-30-July-2017.pdf

These new markets ensured that minimum levels of MW reserves for frequency control were procured in the most economic manner every 5 minutes. A critical feature of these markets was that provision of PFR was no longer mandatory. It was only required from generation that voluntarily participated in the new markets for provision of Contingency FCAS.

As part of these reforms, the Reliability Panel widened the NOFB[4] from ±0.100 Hz to ±0.150 Hz which, along with a probabilistic tolerance of 99%, was intended to reduce the quantity of ancillary services required to be procured. This also resulted in the acceptance of greater variation in frequency under normal operating conditions.

There was no clear, ongoing requirement, or incentive, for any Generator to provide PFR within this widened NOFB. Instead, centralised control of MW reserves obtained through the Regulation FCAS markets via Automatic Generation Control (AGC) became the only mechanism in the NER for frequency control under normal operating conditions.

These new markets initially led to a significant decline in the cost of maintaining frequency control reserves. Even though the provision of PFR was no longer mandatory, most Generators did not change their control systems to reduce provision of PFR immediately, and there was little immediate change in the power system's frequency performance, particularly under normal operating conditions. As explained in Section 2.3, and in more detail in Section 4.1.1, AGC-controlled reserves provide a secondary response that is not equivalent to PFR.

In the last five years, however, power system frequency performance has declined noticeably. On a number of occasions in the past 12 months, NEM frequency has fallen short of the standards specified in the Frequency Operating Standard (FOS) under normal operating conditions. This degradation of frequency performance, in part, prompted the Australian Energy Market Commission's (AEMC) Frequency Control Frameworks Review. At the same time, there have been large increases in the costs of FCAS.

2.3 Role of primary frequency response in frequency control

In a conventional power system, frequency control consists of three layered components:

1. Inertial response (instantaneous)
2. Primary frequency response (within 10 seconds and up to 30 seconds)
3. Secondary frequency response (within 30 seconds and up to 30 minutes)

2.3.1 Inertial response

The inertial response of a power system assists in limiting the rate of change in frequency during large disturbances so that control systems have time to respond and intervene.

Inertial response is provided through the acceleration or deceleration of rotating synchronous machines in response to frequency changes. It is an inherent physical characteristic of rotating machines. The level of inertia in the power system will determine how fast power system frequency will change in the first few seconds of a frequency disturbance.

AEMO recently conducted an analysis of the NEM's inertia requirements and found a shortfall in SA, which ElectraNet, the transmission network service provider (TNSP) in SA, must address.[5]

[4] See section D.3 of the Reliability Panel's Stage One Final Determination: Review of the Frequency Operating Standard, 14 November 2017. Available at: https://www.aemc.gov.au/sites/default/files/content/ce48ba94-b3a9-4991-9ef9-e05814a78526/REL0065-Review-of-the-Frequency-Operating-Standard-Final-for-publi.pdf.

[5] See section 3.2 of AEMO's National Transmission Network Development Plan - December 2018. Available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2018/2018-NTNDP.pdf

2.3.2 Primary frequency response

As described in Section 2.1, PFR is:

- A response to locally-measured frequency and, hence, not subject to centralised control, communications delays and time synchronisation issues.
- Fast-acting – action to correct frequency typically starts immediately.
- An automatic response to adjust generation output to arrest and stabilise frequency, typically in proportion to the measured frequency deviation.

Contingency FCAS is a form of PFR.

Historically in the NEM, only synchronous generating systems provided PFR, however, it is now also being provided by wind, batteries and PV generation. As these technologies will form an increasingly large proportion of the supply mix in future, it is important that any PFR arrangements consider the capabilities and performance of these newer technologies adequately.

2.3.3 Secondary frequency response

Secondary frequency response is a centralised correction of power system frequency and time error, relying on communications, calculations and feedback.

Regulation FCAS is a form of secondary frequency response, which is:

- Dependent on a centralised single frequency reference, with the response also centrally controlled by AEMO's AGC system.
- Complementary to PFR, allowing generation providing PFR to return to its normal set-points (and thus be ready to provide further PFR, if required).
- Slower-acting, primarily because of centralised control and latency in communications through AGC. As AGC is managed via SCADA and includes a range of deliberate rate limits and compensation functions, response delays of tens of seconds can be typical, though slightly faster responses can be achieved in some cases.
- Not continuous following an islanding event, as AGC must be reconfigured for the separate frequency islands before instructions can resume.

2.4 Frequency Control Frameworks Review

The AEMC published its Final Report: Frequency Control Frameworks Review on 26 July 2018 (AEMC Final Report), which dealt with, among other things, PFR in the NEM, particularly under normal operating conditions.

The AEMC accepted that there has been a material deterioration of frequency performance in the NEM under normal operating conditions[6]. To address this, the AEMC made, amongst others, the following recommendation:

> RECOMMENDATION 1: ARRANGEMENTS FOR THE PROVISION OF PRIMARY REGULATING SERVICES
>
> In the long term, market participants should be incentivised to provide a sufficient quantity of primary regulating services to support good frequency performance during normal operation.

[6] AEMC Final Report, page 68.

> In order to develop such a mechanism, the Commission supports AEMO's trialling of changes to generator governor settings in Tasmania and the mainland, and associated technical investigations by AEMO, which are expected to be complete by December 2018.
>
> The Commission recommends that the results of these trials and investigations be used to develop an explicit mechanism to incentivise the provision of a sufficient quantity of primary regulating services to support good frequency performance during normal operation. This will be important to securing sufficient volume of this service in the future for the evolving power system.

The AEMC Final Report reflected AEMO's advice at the time that there was no immediate need to implement regulatory change to address the deterioration pending the results of investigations to understand the issue[7], however, it also noted that the ongoing short-term work program would enable AEMO to assess:

> ... whether there is a need for an interim measure to be put in place before a longer term mechanism for the procurement of a primary regulating response comes into effect. Notwithstanding practical viability, potential interim measures may include:
>
> - those that might not require regulatory change (e.g. AEMO negotiating with generators or issuing directions
> - those that would likely require regulatory change (e.g. mandatory provision of primary frequency control, a new contracting arrangement or valuing positive contribution factors through the causer pays procedure).[8]

Consultation with industry on the need for more PFR in the NEM since publication of the AEMC Final Report has led AEMO to identify disincentives for Generators' provision of PFR under normal operating conditions, which are the subject of this rule change proposal.

2.5 Actions by AEMO subsequent to AEMC Final Report

The AEMC proposed a staged work program to facilitate the formulation of solutions to the problem of deteriorating frequency response in the NEM, including actions to be completed by AEMO to assist the AEMC in its deliberations[9]. AEMO was to monitor and report to the AEMC on a quarterly basis on frequency outcomes following tasks completed in the short-term and medium-term. Table 1 details the status of actions undertaken by AEMO to date.

Table 1 Update on AEMO's actions

Task	Completion	Comments
Survey of generator frequency control settings	April 2018	Survey completed. AEMO is now aware that there is a wide and complex array of control settings in use.
Trial of (increased) primary frequency control in Tasmania	May 2018	Narrowing the governor frequency deadbands on selected Hydro Tasmania generating units resulted in significant and immediate improvement in the control of frequency in TAS under normal operating conditions. The role of AGC settings was less significant than generator governor settings on power system frequency performance under test conditions.
Publish a revised causer pays procedure	Nov 2018	A change was made to allow causer pays calculations to ignore 4-second samples where the frequency indicator and system frequency in a synchronous area are mismatched.
AGC tuning	Ongoing	A trial of increased regulation volumes initially ran from October to December 2018.

[7] AEMC Final Report, pages iii, 37, 58 & 85.
[8] AEMC Final Report, page 38
[9] AEMC Final Report, Table 4.1

Task	Completion	Comments
		Adjustments to AGC tuning were made late 2018, and AEMO has commissioned a further review in mid-2019, which may result in further adjustments.
Investigate the need to increase the quantity of Regulation FCAS on a static or dynamic basis, and doing so if necessary	Ongoing	The quantity of both types of Regulation FCAS for the mainland was increased on a static basis by 50 MW in March 2019 and a further 20 MW in each of April and May 2019.[10] The need for further increases is being evaluated every four weeks, based on the observed change in power system frequency performance under normal operating conditions.
Trial of (increased) primary frequency control in the mainland	Ongoing	The power system separation event on 25 August 2018 superseded the immediate plan for a trial in the mainland along similar lines to that undertaken in TAS earlier in 2018. The proposed rule would facilitate such a trial in the future.
Monitor and report quarterly on frequency outcomes	Ongoing	AEMO has published three reports since the AEMC Final Report.[11]
Coordinate proposed changes to generator governor settings	Ongoing	In November 2018, AEMO rejected a request from a Generator to widen its plant's frequency response deadband settings. AEMO will respond similarly to other requests until more permanent measures are in place to halt the degradation in PFR. AEMO has clarified the deadband settings required from FCAS providers.
AEMO to report on the outcomes of these actions as results become available, through its Ancillary Services Technical Advisory Group, Frequency Control Working Group or published reports (or both).	Ongoing	The Frequency Control Working Group held stakeholder meetings on 26 November 2018 and 17 December 2018. Separate stakeholder meetings were held during February-April 2019 on potential rule changes.

AEMO was of the view during the AEMC's Frequency Control Frameworks Review consultation that there was no immediate need for regulatory change to address the deterioration in frequency performance, pending the results of further investigations to understand the issue.

The power system incident on 25 August 2018 highlighted a more urgent need for rule changes to arrest the ongoing decline in frequency performance in the NEM.

2.6 Incident on 25 August 2018

On 25 August 2018, a lightning strike on a transmission tower structure supporting the two 330 kV QLD–NSW interconnector (QNI) lines caused simultaneous faults on single phases of both circuits of QNI. The QLD and NSW power systems ultimately lost synchronism as a result of these faults, islanding the QLD region. The full sequence of events and analysis is set out in AEMO's final incident report published on 10 January 2019[12] (AEMO Incident Report).

Because 870 MW of electricity was flowing from QLD to NSW at the time, QLD experienced an immediate supply surplus, resulting in a rise in frequency. The remainder of the NEM experienced a supply deficit, resulting in a reduction in frequency. In response to this reduction:

[10] Fact sheet and updates published on AEMO's website at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Frequency-and-time-error-monitoring.

[11] At as 1 June 2019. Available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Frequency-and-time-error-monitoring.

[12] AEMO Final Report: Queensland and South Australia system separation on 25 August 2018. An operating incident report for the National Electricity Market, 10 January 2019. Available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/Qld---SA-Separation-25-August-2018-Incident-Report.pdf.

- The frequency controller on the Basslink interconnector immediately increased flow from TAS to VIC creating a supply deficit in TAS, which caused the disconnection of 81 MW of contracted interruptible load under the automatic under-frequency load shedding scheme AUFLS2 to rebalance the TAS power system.
- The SA–VIC interconnector at Heywood experienced changes in power system conditions that triggered the Emergency APD Portland Tripping scheme, which separated the SA region from VIC at Heywood. At the time of separation, SA was exporting electricity to VIC, which resulted in a supply surplus in SA, causing frequency to rise. In the remaining VIC/NSW island, the supply deficit was increased, and frequency continued to fall until under-frequency load shedding (UFLS) was triggered.

The responses of each type of generation during this event are summarised in Table 2:

Table 2 Responses from all measured generation during 25 August 2018 event

Generation	Percentage of Total Generation Output	Response
Synchronous	~83%[13]	As the key generation technology online during this event, response from synchronous generation was a key factor in power system outcomes. Several large generating systems either did not adjust output in response to local changes in frequency, only responded when frequency was outside a wider band than has been observed in the past, or limited, or restricted, their response to frequency changes. Large oscillatory changes in output was observed from some generating units.
Distributed PV	14%	Generally contributed to lowering frequency in SA and QLD by reducing output, but was unable to assist VIC or NSW, as those regions needed an increase in supply. Approximately 15% of sampled systems installed before October 2016 disconnected and, of those installed after October 2016, around 15% in QLD and 30% in SA did not demonstrate the over-frequency reduction capability required by AS/NZ4777.2-2015.
Large-scale solar PV	2.3%	Generally contributed to lowering frequency in SA and QLD but did not assist in limiting the initial frequency excursions, due to slow response speed.
Wind	1.2%	Did not assist in correcting the frequency deviations. Four wind farms in SA reduced output to zero due to an incorrect protection setting.
Large-scale battery	<0.1%	Assisted by containing the initial decline in power system frequency, and then rapidly changed output from generation to load to limit the over-frequency in SA following separation from VIC.

While most Generators met their obligations for frequency response under their performance standards and FCAS dispatch, the lack of PFR from some generating systems contributed to significant technical challenges in arresting and controlling power system frequency, particularly in the earlier stages of the event.

The last time QLD separated from the rest of the NEM was on 28 February 2008, where an event in NSW led to the loss of the QLD-NSW DC interconnector, Directlink, followed by the loss of QNI. A comparison of key, relevant outcomes following the two events is detailed in Table 3:

Table 3 Event Comparison 2008 and 2018

	2008	2018
Net loss of supply QLD to NSW	1,091 MW	870 MW
Other regions separated	NIL	South Australia

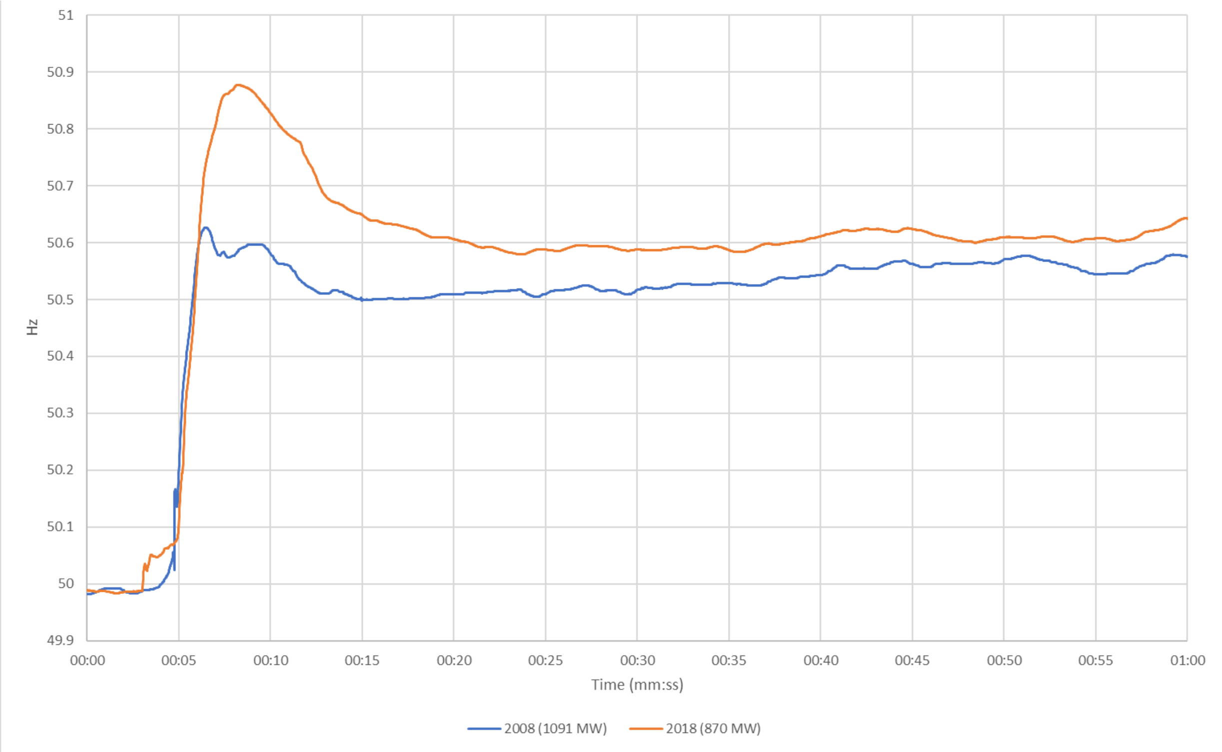
[13] The percentages of output shown in Table 2 differ from those in the AEMO Incident Report because they take rooftop PV generation into account as generation, rather than demand reduction.

	2008	2018
Maximum frequency QLD	50.62 Hz	50.9 Hz
Minimum frequency NSW	49.55 Hz	48.85 Hz
Load interrupted	NIL	997.3 MW (UFLS) 81 MW (contracted)

No two power system disturbances are ever the same, and AEMO acknowledges that there are material differences in power system conditions between the two events, notably outside of QLD. The differences in frequency outcomes for the separated QLD region between the 2008 and 2018 events, however, are significant.

The spread of maximum frequency experienced in QLD in 2018 as compared with 2008 provides evidence that the power system's resilience to large contingencies over the last ten years has declined, as does the significant shedding of load required in 2018 to arrest an event with a similar, but larger, initiating trigger in 2008. This decline is depicted graphically in Figure 1:

Figure 1 QLD following separation in 2008 vs 2018



Some other observations from the 2018 event are noteworthy:

- A range of disparate frequency control actions occurred in 2018, including some that combined to exacerbate frequency deviations. Additional PFR would have counteracted or stabilised some of these outcomes.
- PFR from some new generating systems installed after the 2008 event was delayed to the point where it made little or no contribution to arresting the initial frequency deviation after the initial disturbance.
- Similar-technology asynchronous generating systems installed after 2008 tripped because of the operation of near-identical frequency protection settings, and poor ongoing control of frequency[14]. Additional PFR would have reduced the likelihood of this outcome.

[14] AEMO Incident Report, page 87.

The 25 August event illustrates the extent of the decline in power system frequency performance, and the need for immediate measures to arrest it. In the AEMO Incident Report, AEMO made several recommendations to address this decline in frequency performance, including[15]:

1. AEMO to work with the AEMC, AER and Generators to establish appropriate interim arrangements, through rule changes as required, to increase PFR at both existing and new (synchronous and non-synchronous) generation connection points where feasible, by Q3 2019.
2. AEMO to support work on a permanent mechanism to secure adequate PFR as contemplated in the AEMC's Frequency Control Framework Review, to identify any required rule changes to be submitted to the AEMC by the end of Q3 2019 with a detailed solution and implementation process completed by mid-2020.

This rule change proposal addresses the first of these recommendations, in part. It removes disincentives to the provision of PFR under normal operating conditions within the NOFB.

AEMO requests this rule change proposal be treated as non-controversial, allowing for rapid implementation of these changes and to facilitate increased provision of PFR in the NEM under normal operating conditions.

3. CURRENT FRAMEWORK

3.1 Frequency management in the NEM

Frequency control in the NEM is one of the AEMO power system security responsibilities under Chapter 4 of the NER.

These responsibilities arise from the operation of clause 4.3.2(a), which details AEMO's obligation to maintain power system security:

4.3.2 System security

(a) *AEMO* must use its reasonable endeavours, as permitted under the *Rules*, including through the provision of appropriate information to *Registered Participants* to the extent permitted by law and under the *Rules*, to achieve the *AEMO power system security responsibilities* in accordance with the *power system security* principles described in clause 4.2.6.

The first of the power system security principles listed in clause 4.2.6 is that AEMO is to operate the power system to maintain it in a secure operating state:

4.2.6 General principles for maintaining power system security

The *power system security* principles are as follows:

(a) To the extent practicable, the *power system* should be operated such that it is and will remain in a *secure operating state*.

For the power system to be in a secure operating state, it must first be in a satisfactory operating state, as detailed in clause 4.2.4(a):

4.2.4 Secure operating state and power system security

(a) The *power system* is defined to be in a *secure operating state* if, in *AEMO's* reasonable opinion, taking into consideration the appropriate *power system security* principles described in clause 4.2.6:

(1) the *power system* is in a *satisfactory operating state*; and

[15] AEMO Incident Report, pages 8 & 88.

(2) the *power system* will return to a *satisfactory operating state* following the occurrence of any *credible contingency event* or *protected event* in accordance with the *power system security standards*.

Finally, to be in a satisfactory operating state, one of the first criteria is that frequency is maintained within the normal operating frequency band (NOFB) specified in the frequency operating standards (FOS)[16], as stated in clause 4.2.2(a):

4.2.2 Satisfactory Operating State

The *power system* is defined as being in a *satisfactory operating state* when:

(a) the *frequency* at all energised *busbars* of the *power system* is within the *normal operating frequency band*, except for brief excursions outside the *normal operating frequency band* but within the *normal operating frequency excursion band*;

AEMO's obligation to manage power system frequency is reinforced by clause 4.4.1, which states:

4.4.1 Power system frequency control responsibilities

AEMO must use its reasonable endeavours to:

(a) control the *power system frequency*; and

(b) ensure that the *frequency operating standards* set out in the *power system security standards* are achieved.

Frequency can only be managed effectively if all elements of the power system are performing in a way that assists AEMO to meet these obligations.

Clause 4.4.1 (a) requires control of power system frequency, but under the present arrangements frequency is, in fact, increasingly uncontrolled under normal operating conditions. It is continually drifting in an uncontrolled manner across the entire range of the NOFB.

Clause 4.4.1 (b) requires the maintenance of frequency within the parameters specified in the FOS under normal operating conditions[17], however it has become increasingly difficult to meet these requirements.

3.2 Tools under the NER available to AEMO to control frequency

The NER provide different tools available to AEMO to control power system frequency. Regulation FCAS is primarily designed to be used during normal operating conditions, while other tools are primarily designed to be used following contingencies. In reality, following a contingency, they are co-optimised to address different needs in different timeframes.

3.2.1 Tools available under normal operating conditions

The only tool currently available to AEMO under the NER to control frequency under normal operating conditions is market ancillary services, specifically Regulation FCAS. Although the requirements specified in the MASS for Regulation FCAS look like they should operate to keep power system frequency close to 50 Hz, in fact, they act only to maintain or restore power system frequency somewhere within the NOFB.

3.2.2 Tools available following contingencies

The tools available to control power system frequency following contingencies are:

[16] Available at: https://www.aemc.gov.au/sites/default/files/2018-08/REL0065%20-%20The%20Frequency%20Operating%20Standard%20-%20stage%20one%20final%20-%20for%20publi....pdf.

[17] See the fact sheet on Regulation FCAS recently published by AEMO at http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Frequency-and-time-error-reports/Regulation-FCAS-factsheet.pdf.

1. Contingency FCAS – a market ancillary service designed to be provided after power system frequency exits the NOFB.
2. Load Shedding – there are automatic UFLS schemes operating in the NEM, which are designed as a last line of defence to avert a power system collapse following a supply-demand mismatch that cannot be corrected by any other means.
3. Generation shedding - over-frequency generator shedding (OFGS) is, essentially, the inverse of UFLS. As with load shedding, it is a last resort for use in emergencies where other options are not available.
4. Directions – under certain emergency conditions and subject to technical availability, AEMO can issue directions to participants (under the NEL and NER), to assist in controlling frequency.
5. Protected events – AEMO may recommend to the Reliability Panel that a specified non-credible contingency event impacting power system frequency be classified as a 'protected event', allowing AEMO to take specified operational action to manage the associated risk.

3.3 Generator obligations to support frequency control

3.3.1 Obligation to meet performance standards

While AEMO is responsible for the management of power system frequency in the NEM, Generators are required to support AEMO in this endeavour by meeting their performance standards related to frequency, as stated in clause 4.4.2(b):

> **4.4.2 Operational frequency control requirements**
>
> To assist in the effective control of *power system* frequency by *AEMO* the following provisions apply:
>
> …
>
> (b) Each *Generator* must ensure that all of its *generating units* meet the technical requirements for frequency control in clause S5.2.5.11;

Schedule S5.2.5 contains the technical requirements that Generators must meet, some which relate to power system frequency.

Most of these requirements specify an automatic access standard and a minimum access standard and, in some cases, additional parameters for a negotiated access standard. The automatic access standard is the highest that can be required, and the minimum access standard is the lowest that might be acceptable in certain circumstances. A negotiated access standard may be agreed somewhere between the minimum access standard and the automatic access standard but, since 5 October 2018,[18] must be as close as possible to the automatic access standard. Under clause 5.3.4A, Generators seeking connection to the national grid must propose access standards, which both AEMO and the connecting LNSP must consider. After approval, these will form the generating system's performance standards.[19]

Clause S5.2.5 was amended on 27 September 2018 by the *National Electricity Amendment (Generator technical performance standards) Rule* 2018 No. 10.

Clause S5.2.5.11 was one of the provisions amended. The automatic access standard in clause S5.2.5.11 requires Generators to be capable of operating their generating systems in a way that is responsive to changes in power system frequency such that the Generator can offer measurable amounts of all market ancillary services for power system frequency control.

[18] Following commencement of the National Electricity Amendment (Generator technical performance standards) Rule 2018 No. 10.

[19] A similar process applies to alterations to generating systems under clause 5.3.9.

The minimum access standard merely requires that generating systems have the capability to operate in frequency response mode.

Notably, the general requirement in clause S5.2.5.11(i)(4) states:

> (4) a *generating system* is required to operate in *frequency response* mode only when it is enabled for the provision of a relevant *market ancillary service*;

AEMO is aware that this provision is being interpreted as not requiring Generators to operate their generating systems in frequency response mode if they are not enabled for the provision of a relevant market ancillary service. Some, in fact, have interpreted this as a requirement to disable their frequency response mode when not providing a market ancillary service. Generators who consequently adjust their plant to be frequency-responsive only when providing a market ancillary service[20] will only reduce AEMO's ongoing control of power system frequency.

3.3.2 PFR inside the NOFB

Market ancillary services only ensure delivery of PFR outside of the NOFB.

There is currently no arrangement that obliges (or rewards) delivery of PFR from any generating system to support frequency control within the NOFB. This means that AEMO only has the centralised AGC control of Regulation FCAS to manage frequency under normal operating conditions.

4. STATEMENT OF THE PROBLEM

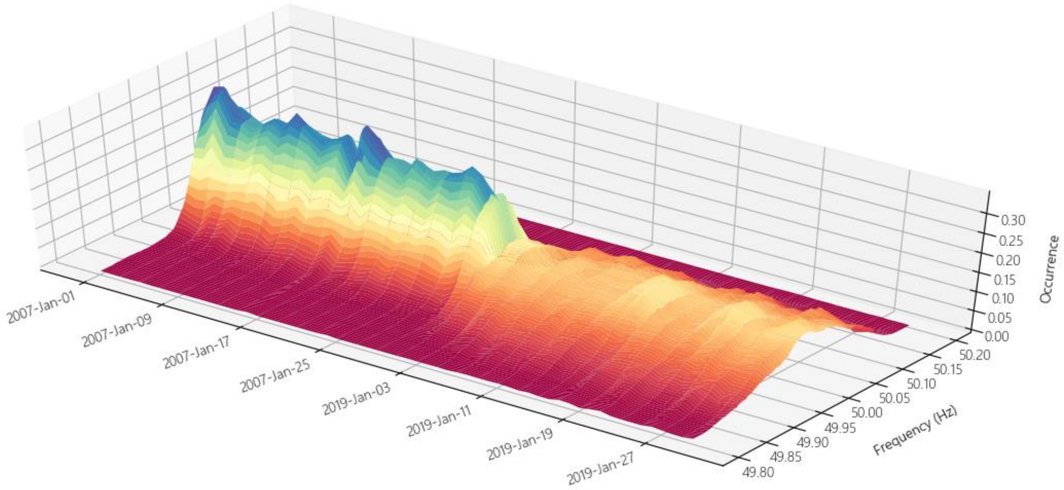
4.1 Underlying Issue: Poor frequency performance under normal operating conditions

Frequency performance in the NEM under normal operating conditions continues to decline. Figure 2 and Figure 3 show how frequency control under normal operating conditions has deteriorated over the last five years, with a significant increase in the variation of frequency away from 50 Hz over time.

Figure 2 shows that, while frequency has generally been maintained within the NOFB, the spread of power system frequency away from 50 Hz has been steadily increasing, with a sharp decline in performance from 2015.

[20] Without seeking AEMO's prior approval, as required by clause 4.9.4(e) of the NER.

Figure 2 NEM Mainland Frequency Histogram - Jan 2007 to May 2019



To understand frequency performance better, a snapshot from 2005 (in green) overlaid against one from 2017 (in black) is shown in Figure 3.

Figure 3 NEM Frequency Performance under Normal Conditions (2005 and 2018)

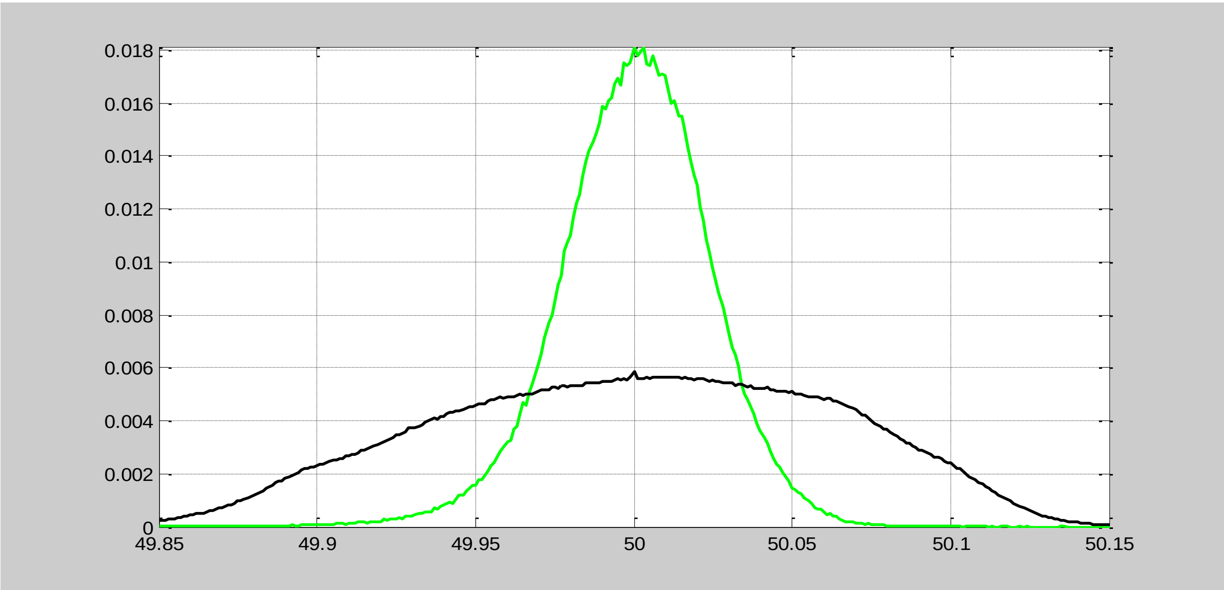
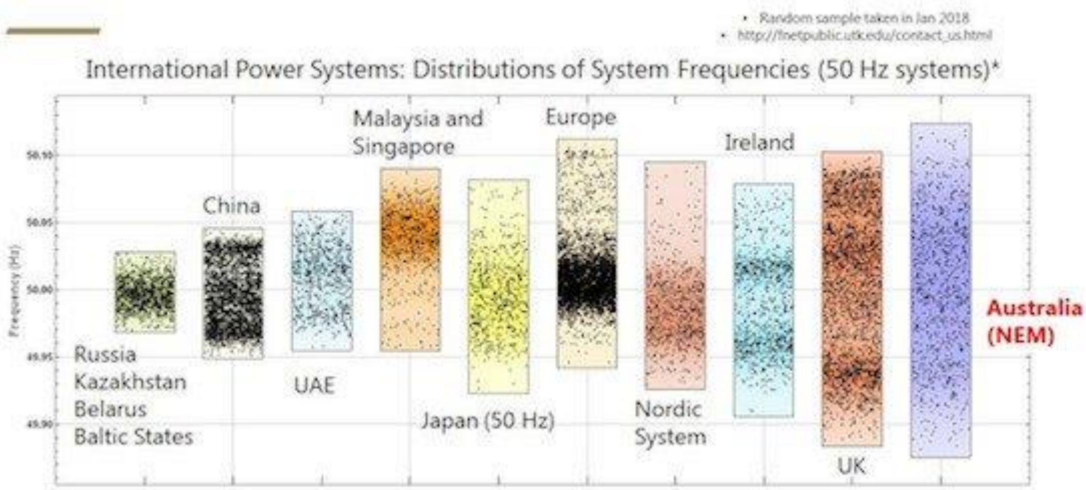


Figure 4 compares NEM frequency performance under normal operating conditions against other 50 Hz power systems, showing that the NEM's level of frequency variation is wider that other comparable systems, both smaller and larger than the NEM[21].

[21] Source: https://www.linkedin.com/pulse/system-frequency-what-doing-why-does-matter-bruce-miller/.

Figure 4 Comparative frequency performance across various power systems



Generators have identified several disincentives to the delivery of PFR under normal operating conditions. This rule change proposal seeks to remove those as soon as possible to facilitate the provision of PFR that may stop further decline in power system frequency performance.

4.1.1 Causes of poor frequency performance under normal operating conditions

The causes of poor frequency performance under normal operating conditions can be summarised as:

- A decline in the provision of PFR by Generators, which is exacerbated by feedback loops inherent in the NEM's design.
- An increase in the variability of generation and load, which can be exacerbated by increasing levels of renewable generation whose output may be subject to weather driver variability.
- Inappropriateness of Regulation FCAS as a control mechanism for maintaining frequency as close as practicable to 50 Hz.

Fewer generating units are now providing PFR

AEMO engaged DIgSILENT to review frequency performance in the NEM in 2017[22]. In its report, which was submitted to the AEMC during the Frequency Control Frameworks Review, DIgSILENT indicated that it had surveyed eight Generators who collectively operated over 30,000 MW of scheduled generation in the NEM. The responses to this survey did not include frequency response characteristics of non-synchronous generation.

Of the 36 power stations considered by DIgSILENT, 26 were operating with a wide frequency response deadband and there were plans to widen the deadbands on more power stations in the foreseeable future. The AEMC also noted that Generators acknowledged having detuned their scheduled generating systems' responsiveness to frequency variations under normal operating conditions, some to avoid exposure to causer pays liabilities[23].

Following the DIgSILENT work, AEMO requested details of frequency control settings from a broader range of Generators. The results indicated that many major power stations are still providing PFR to varying degrees of frequency deviation, particularly for the largest levels of frequency deviation. AEMO received

[22] DIgSILENT Pacific, Review of Frequency Control Performance in the NEM under Normal Operating Conditions, 19 September 2017. Available at

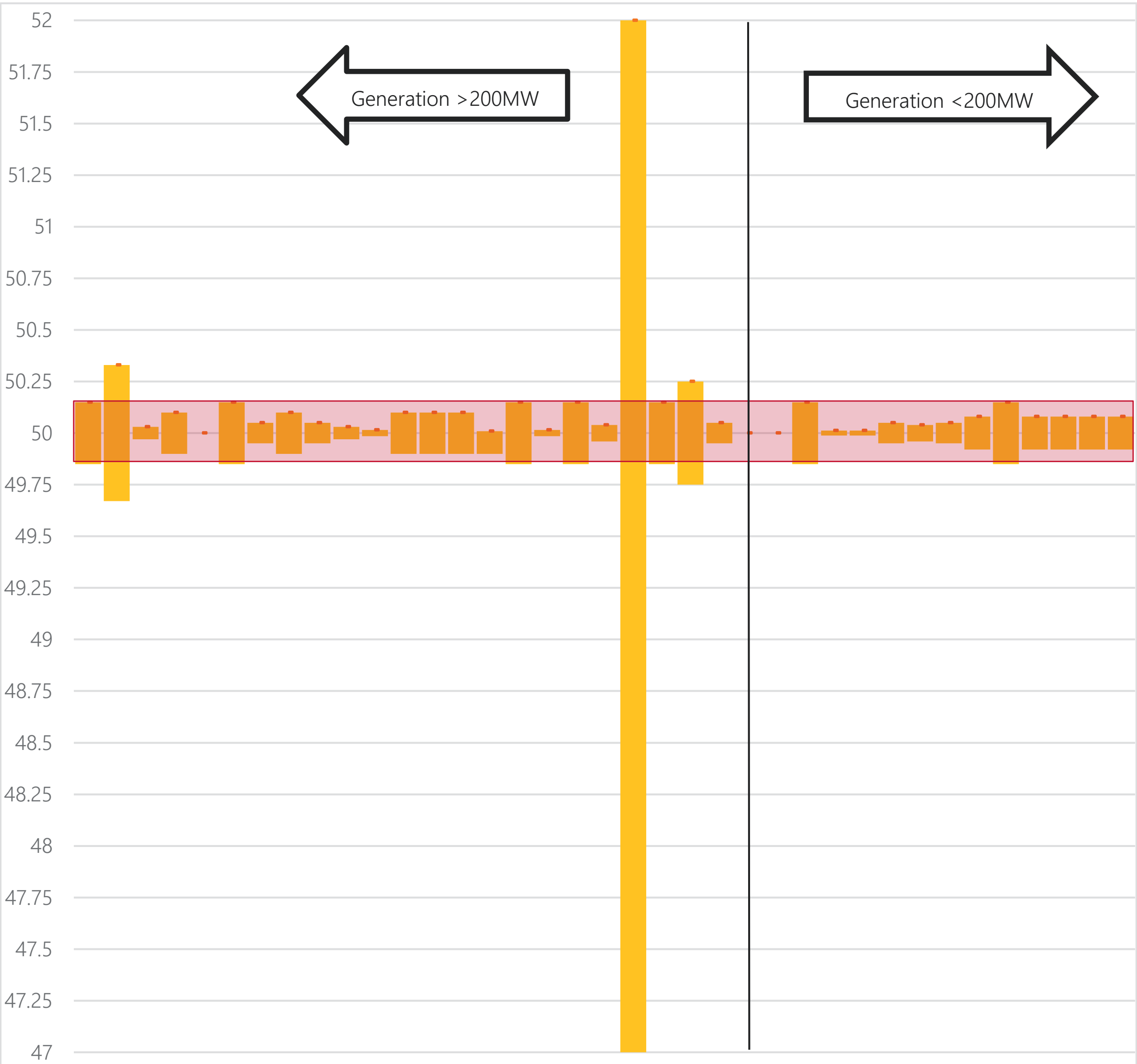
[23] AEMC Final Report, page 69. For further information about causer pays, see AEMO's Regulation Contribution Factor Procedure, available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Regulation-FCAS-Contribution-Factors-Procedure.pdf.

data for about 45 scheduled generating systems in the NEM, representing 32,036.6 MW of NEM capacity (around 70%).

Of those 45, detailed deadband settings were provided for 37 scheduled generating systems, representing 25,785 MW of NEM capacity (around 60%)[24]. Figure 5 depicts these frequency response deadband settings against the NOFB, represented by the pink shaded horizontal bar. The chart also indicates whether the surveyed scheduled generating systems have a capacity of more, or less, than 200 MW.

Figure 5 shows that a significant number of the larger surveyed scheduled generating systems' frequency response deadband settings are set either at the NOFB or outside it, which suggests that they are providing PFR only when power system frequency exits the NOFB.

Figure 5 Frequency response deadbands in use (based on survey results)



The chart, however, does not tell the full story. Even where deadbands are set within the NOFB, the generating systems do not necessarily operate in frequency response mode

Of these scheduled generating systems, information received by Generators indicates that:

[24] The responses for the remaining generating systems were either equivocal or setting information was not provided.

- Only twelve (around 15% by capacity) are always operating in frequency response mode using the stated frequency response settings.
- A further seven only do so when not restricted by other factors, such as temperature, or other plant limits.
- Six only operate in frequency response mode when providing FCAS.
- There was insufficient information as to the frequency with which the scheduled generating systems were operated with the stated frequency response settings from the remaining responses.

The outlier in Figure 5, which has its frequency response settings at 47-52 Hz, is providing no PFR.

The implication from these results is that while a substantial proportion of the largest generating systems in the NEM can operate in frequency response mode within the NOFB, only a small proportion is consistently operated in this manner.

NEM design factors incentivise reduced PFR from generation

AEMO's review of international 50 Hz power systems confirms that the NEM's current design is unique in neither incentivising or mandating any PFR in response to frequency deviations under normal operating conditions within a band of ±0.150 Hz, and relying entirely on the use of secondary frequency control via AGC.

The design of the NEM has given rise to the operation of several interconnected vicious cycles leading to a reduction in PFR from generation:

- Increasing power system frequency deviations may require greater response from frequency-responsive generating plant, which can increase wear and tear. Generators who can adjust their plant to be less frequency-responsive have done so to minimise the wear and tear to their plant. The reduced response results in greater overall volatility in power system frequency. Those Generators whose generating systems might still provide PFR in response to smaller changes in frequency see their plant responding more because of that and, inevitably, will remove their plants' frequency responsiveness, leading to greater volatility affecting the remaining generating plant with frequency responsiveness, and so on. Eventually, the only frequency-responsive generating systems remaining in the NEM will be those that, for technical or economic reasons, are unable to prevent their plant from responding. These remaining generating systems will continue to suffer increasingly excessive movement. AEMO was informed by some Generators that this has been of concern to them during informal consultation in preparation for this rule change proposal.
- Generators are required by the NER to comply with their dispatch targets. Frequency-responsive generation that moves automatically to correct frequency deviations in the power system can result in deviation from those targets, so Generators modify their plant controls to ensure compliance. Frequency deviations in the power system increase as a result, and so does the risk that the remaining Generators will not be able to follow their dispatch targets accurately, so more Generators adjust their plant controls to ensure greater dispatch target compliance[25]. Six out of eight Generators surveyed by DIgSILENT cited compliance with dispatch instructions[26] as a reason for changing their plant's frequency response.[27] Informal consultation by AEMO in preparation for this rule change proposal yielded similar responses from Generators.
- Market Generators who wish to minimise their exposure to the recovery of Regulation FCAS costs via the causer pays process will adjust their plant to follow their dispatch targets to meet the criterion that will minimise their liability under clause 3.15.6A(k)(5)(i) or (7)(i) of the NER. This increases the

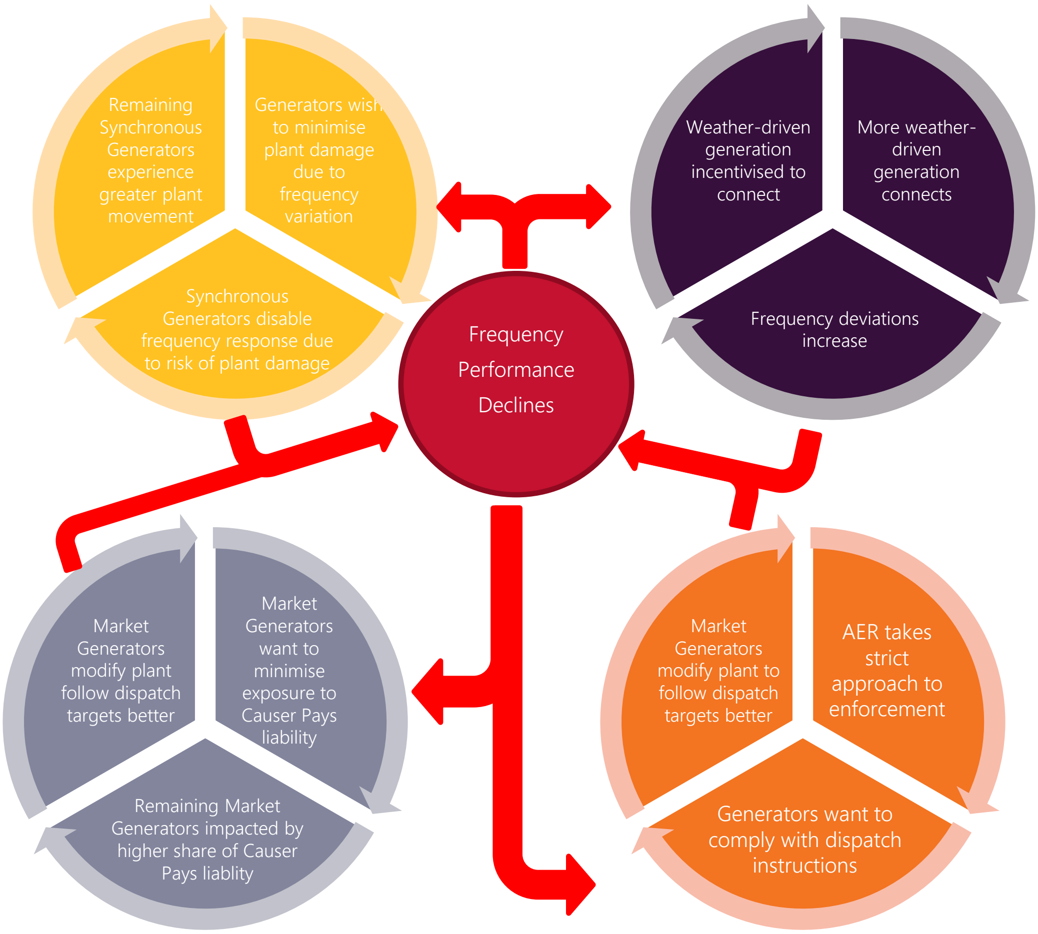
[25] See also the discussion in DIgSILENT's report, pages 26-27.
[26] Required by clause 4.9.8 of the NER.
[27] See the discussion on page 42 of DIgSILENT's report.

allocation of causer pays liabilities to the remaining Market Generators. Those remaining Market Generators will, if they can, adjust their plant to follow their dispatch targets to reduce that exposure. This pattern repeats itself until the remaining Market Generators are either unable to adjust their plant accordingly, or their gains from the energy market outstrip their exposure to causer pays liabilities[28]. Six Generators surveyed by DIgSILENT stated that the attempts to minimise causer pays liabilities contributed to their decision to change their plant's frequency response[29]. Informal consultation by AEMO in preparation for this rule change proposal yielded similar responses from Generators.

The DIgSILENT review indicates that the response to these incentives have not been played out fully, with the potential for ongoing decline as Generators seek to implement plans to widen their deadbands for regulatory, economic or technical reasons.

Figure 6 illustrates how these factors interact with each other to contribute to declining frequency performance, especially under normal operating conditions:

Figure 6 Summary of Factors Contributing to Decline in Power System Frequency



Factors that normally impact power system frequency

Frequency will change when there is a supply-demand MW mismatch. The frequency performance of the power system is determined by:

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29 See the discussion on page 42.

- The total level of MW imbalance between instantaneous supply and demand, which can have many individual underlying causes.
- The total response of all generation to frequency changes that arise from these MW imbalances.

The MW imbalance between supply and demand can occur at varying levels, be caused by a variety of factors, and occur over a variety of timeframes. Causes include:

- Demand changing constantly within a dispatch interval, with both predictable and random components, over timeframes of seconds to minutes.
- Demand forecasting errors, requiring correction over market dispatch timeframes.
- Supply forecasting errors, such as:
  - Forecasting inaccuracy in AWEFS, AEMO's wind energy forecasting system, as noted by DIgSILENT in a report prepared for AEMO and submitted to the AEMC during its Frequency Control Frameworks Review.[30]
  - Unexpected changes in weather conditions impacting solar- or wind-dependent generation output, particularly changes inside the 5-minute dispatch cycle.
- Sudden contingency events, such as:
  - Tripping or disconnection of generation, load or transmission lines connecting them.
  - Simultaneous response of inverter-controlled plant to a change in power system conditions, such a fault or other system disturbance. This may occur at the distribution or transmission level.

Increasing risk of larger supply-demand mismatches

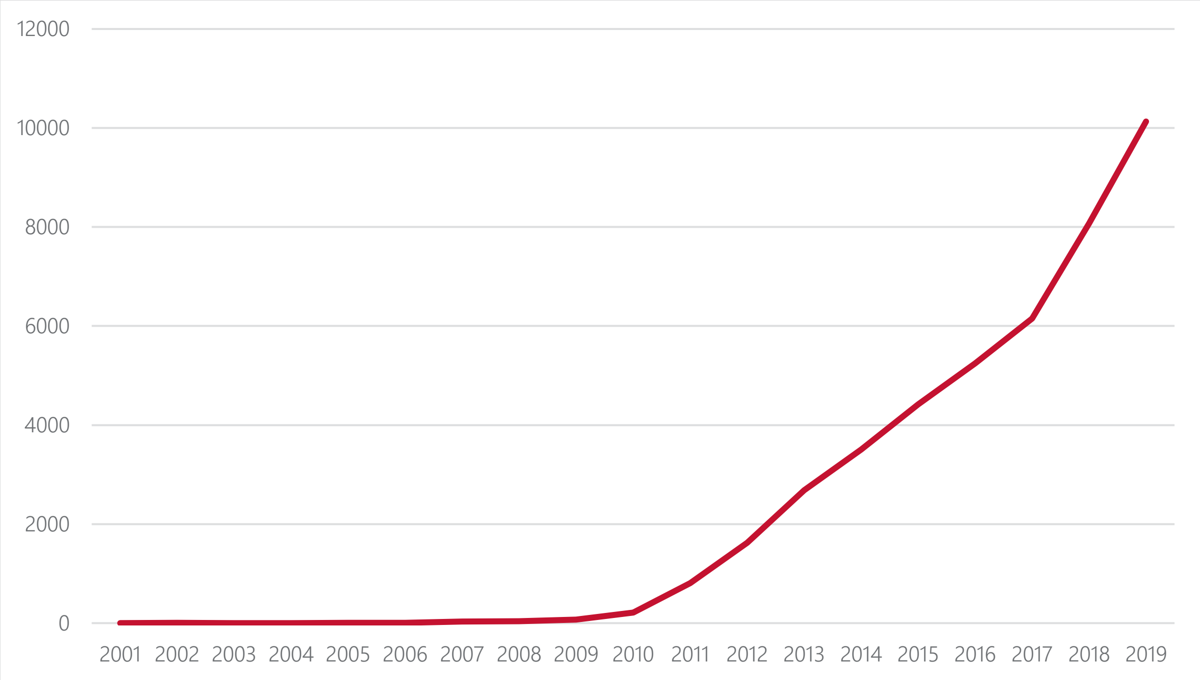
The impact of some of the factors normally affecting supply-demand mismatches is expected to increase over time, increasing the need for PFR under normal operating conditions, and further increasing the need for removal of disincentives to its provision. One such reason predicted by AEMO is the large forecast increase in solar PV generation (rooftop and large scale) in the NEM[31].

Data from the Australian PV Institute Solar Map shows that PV generation in Australia has grown at a rapid rate, as demonstrated by Figure 7:

[30] DIgSILENT Pacific, Review of Frequency Control Performance in the NEM under Normal Operating Conditions, 19 September 2017. Available at: https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/Other_Meetings/ASTAG/371100-ETR1-Version-30-20170919-AEMO-Review-of-Frequency-Control.pdf.

[31] AEMO observations: Operational and market challenges to reliability and security in the NEM, March 2018. Available at: https://www.aemo.com.au/-/media/Files/Media_Centre/2018/AEMO-observations_operational-and-market-challenges-to-reliability-and-security-in-the-NEM.pdf.

Figure 7 Cumulative installed solar PV in Australia (MW)



Ten years ago, the amount of solar PV generation barely registered as a proportion of total connected generation. The Australian PV Institute estimates that, as of 30 September 2018, there were over 1.95 million PV installations in Australia, with a combined capacity of over 10.14 GW. If the estimated contribution of Western Australia and the Northern Territory is deducted (about 11%), that leaves around 9.02 GW of installed PV out of a total of 50.654 GW of generation (around 18%) in the NEM[32].

In its most recent Electricity Statement of Opportunities, AEMO forecast a total installed solar PV capacity of over 40 GW of NEM PV, with around 20 GW of this comprising distributed rooftop PV[33] by 2038.

Large transmission PV generation installations can be subject to rapid cloud shadowing, resulting in short-term output changes. This introduces short-term supply-demand MW mismatches that will manifest as a frequency change if it is not corrected.

For various reasons outside the scope of this rule change proposal, rooftop PV is very challenging to forecast with high accuracy. Measures are being taken to improve AEMO's ability to forecast in this area[34], so it is not an issue that this rule change proposal seeks to address.

While improving forecast accuracy would potentially allow more targeted volumes of frequency control resources to be procured, this does not change the underlying need to rely on PFR and Regulation FCAS together to address supply-demand mismatches within the dispatch interval timeframe.

Inadequacy of market ancillary services to address poor frequency performance under normal operating conditions

The design of the FCAS markets has proven to be inadequate to address the challenges AEMO now faces to manage power system frequency under normal operating conditions. As noted later in Section 4.1, the

[32] Data sourced from Australian PV Institute website at: http://pv-map.apvi.org.au/. Total *NEM generation* sourced from AEMO's Generation Information Page at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[33] See page 27. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf.

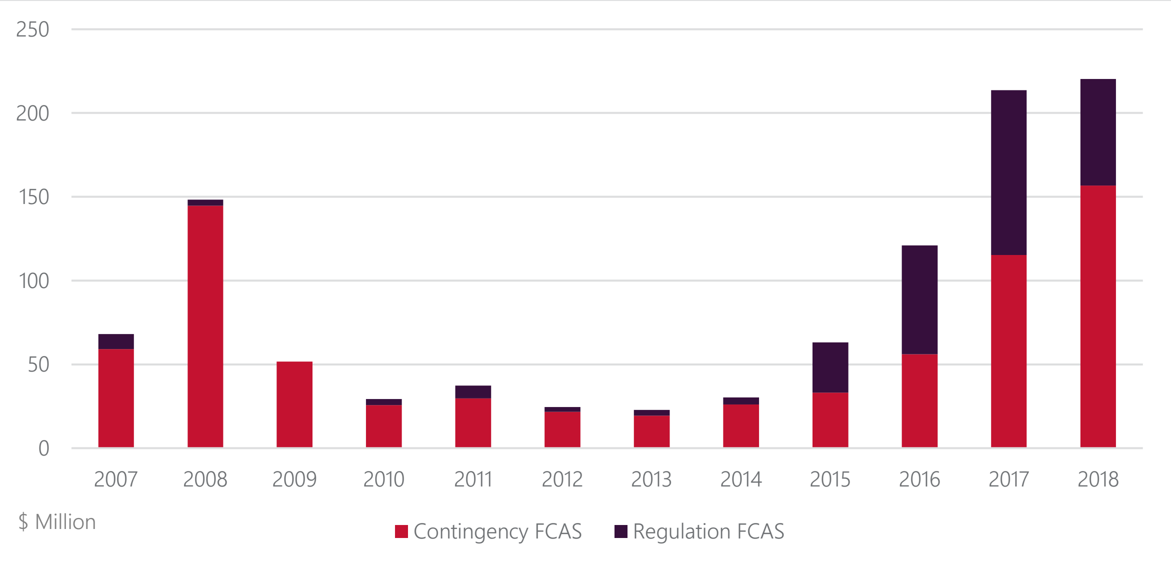
[34] Such as the information sources in accordance with the Demand Side Participation Information Guidelines (available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Demand-Side-Participation-Information-Guidelines) and AEMO's Distributed Energy Resources Program (see http://aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program).

use of Regulation FCAS alone is not capable of controlling frequency within the NOFB under normal operating conditions.

Contingency FCAS is not designed to assist in controlling frequency under normal operating conditions. On the contrary, the way AEMO measures the provision of Contingency FCAS, as specified in the MASS, incentivises the delayed delivery of PFR until power system frequency crosses the edge of the NOFB, reducing delivery of PFR within the NOFB, and further increasing a dependence on Regulation FCAS.

While frequency performance within the NOFB has declined, the cost of Regulation FCAS has risen sharply over roughly the same period, as shown in Figure 8[35]:

Figure 8 Cost of FCAS in the NEM



It should be noted that the base volume of Regulation FCAS procured over the years shown in Figure 8 was steady at 130 MW for Raise Regulation, and 120 MW for Lower Regulation.

The cost of Regulation FCAS for Q1 2019 was around $18 million, however, the increase in cost for 2019 will be inflated by the procurement of additional volumes from 22 March 2019[36].

The quantity and cost of regulation FCAS enabled over the last 5 years has increased while the performance of frequency control within the NOFB, the band within which Regulation FCAS is meant to control frequency, has been declining. As outlined below, while the regulation FCAS is effective at controlling slow frequency deviations, it is not effective at controlling the higher speed deviations that are were previously damped by primary frequency control. As such the Regulation FCAS markets are no longer sufficient for control of frequency in the NOFB.

AGC is an inadequate control mechanism

Figure 9 provides some insight into why the close control of frequency under normal operating conditions using only Regulation FCAS, which is a form of secondary frequency control, is unlikely to be successful.

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[35] The high cost of Contingency FCAS in 2008 was due to one of the HWTS – LYPS 500kV Lines being down for maintenance when a second one tripped, leaving only one line remaining on 23 July 2008. This caused NEMMCO (as AEMO was then known) to declare the failure of that remaining line the greatest single contingency in the NEM, necessitating the procurement of large volumes of FCAS.

[36] See Section 7.1 for further information.

Figure 9 Actual system frequency vs frequency measured by SCADA

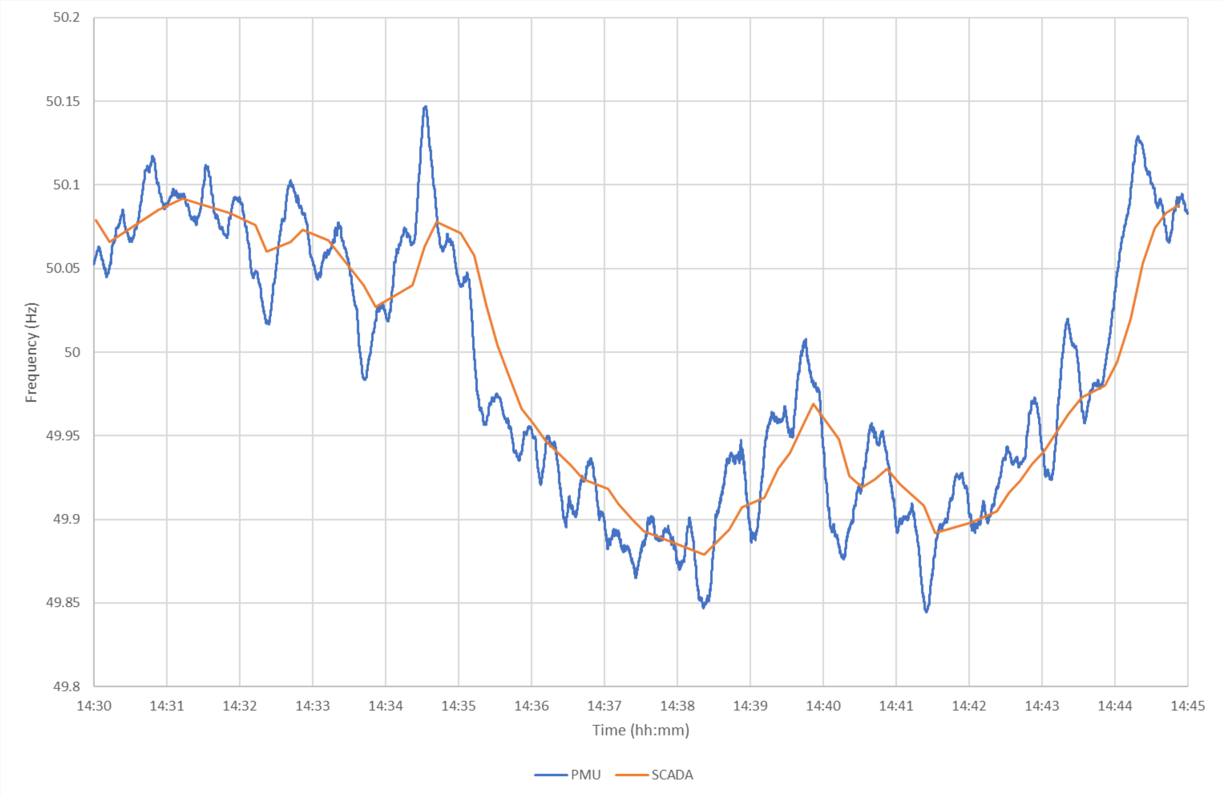


Figure 9 shows a randomly selected 15-minute period and compares the power system frequency used as an input to AGC, centrally measured by SCADA, and actual instantaneous power system frequency as measured by a high-speed measurement device (PMU).

It shows periods where AGC believes frequency is on the opposite side of 50 Hz to where it is. There are also differences of 0.050 to 0.100 Hz in the AGC input frequency value and actual power system frequency.

Once it has measured frequency, AGC will take at least 4-8 seconds to begin issuing commands to generating units to correct frequency deviations, resulting in further delays. AGC by design includes deliberate smoothing of generator control responses, which further reduces response rates for many generators providing Regulation FCAS to correct frequency deviations. Generator response is (again by design) not synchronised, but rather generators respond at varying rates.

If frequency was moving slowly and smoothly, AGC might have previously been able to assist in controlling frequency to bring it closer to 50 Hz. This might have been the case in 2001, when FCAS markets were initially established, but it is clearly not the case now. It is unrealistic to expect a slow response control system such as AEMO’s ACG to stably control a more rapidly moving control variable such as NEM frequency.

This inadequacy of AGC-controlled Regulation FCAS as the sole mechanism for frequency control under normal operating conditions is one of many reasons why additional PFR within the NOFB is required. Figure 9 highlights some of the limitations of secondary frequency control via AGC and suggests that further tuning or adjustment of AGC performance alone is unlikely to produce significant improvement in power system frequency outcomes.

As noted in AEMO's advice to the AEMC's Frequency Control Frameworks Review[37], primary and secondary frequency control are quite different services in terms of their control paradigm, response time, sustain

[37] Available at: https://www.aemc.gov.au/sites/default/files/2018-03/Advice%20from%20AEMO%20-%20Primary%20frequency%20control.PDF

time and controlling range, and are not broadly interchangeable, but need to operate in a complementary manner.

4.1.2 Implications of poor frequency performance

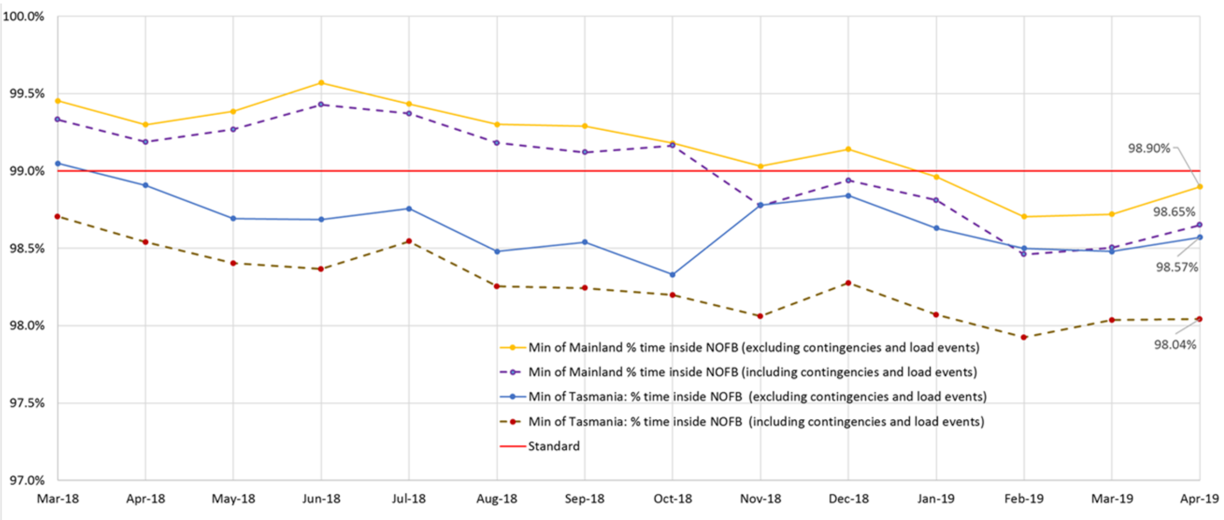
AEMO's ability to meet the Frequency Operating Standard

The Reliability Panel's 2018 Annual Market Performance Review[38] noted that the NEM's frequency performance has continued to deteriorate. Some requirements of the FOS for normal operation were not met in both the NEM mainland and Tasmania during 2017-18:

- On the mainland, frequency remained within the NOFB more than 99% of the time but there were 50 events where frequency took longer than allowed in the FOS to be returned to the NOFB following a disturbance.
- In Tasmania, frequency performance was poorer, where it was outside of the NOFB for more than 1% of the time for 11 months. Further, there were 295 events where frequency took longer than allowed in the FOS to be returned to the NOFB following a disturbance.

While frequency control is AEMO's responsibility, the reality is that AEMO cannot control frequency within the NOFB under normal operating conditions using only the tools available to it. AEMO needs assistance from plant capable of responding appropriately to frequency changes in the power system to improve frequency outcomes in a way that achieves a reasonable level of control close to 50 Hz. This is evident in Figure 10, which shows the rolling 30-day average of frequency in for the mainland and Tasmania over the last 12 months.

Figure 10 Minimum 30-day rolling average of percentage of time frequency within the NOFB



Ability to predict power system behaviour

Tools and models

Power system operators commonly include frequency assessments as part of their dynamic security assessment tools, which run dynamic simulations to confirm power system security close to real-time. With the rapid changes affecting power systems globally, these tools are becoming increasingly important.

Models that consistently and accurately simulate the frequency performance of generating units are a prerequisite to developing these tools. A lack of consistency and certainty of PFR delivery from generation

[38] Available at https://www.aemc.gov.au/market-reviews-advice/annual-market-performance-review-2018.

when making these assessments makes these tools less accurate, and, consequently, less useful. The resulting 'wandering' frequency of the power system within the NOFB also creates uncertainty about the true operating limits of the power system. This makes the simulation of events and the design of emergency frequency control schemes more challenging. It also means the power system is likely to be less resilient to non-credible contingencies and complex events. When frequency is already drifting away from 50 Hz, a relatively smaller change in frequency can trigger emergency frequency control schemes or similar emergency responses, with no time for other corrective responses to occur.

4.2 How the issue manifests in the Rules

Several Generators have concluded that the provision of PFR could result in their failure to meet their dispatch targets, and that this gives rise to two perceived risks:

1. Being identified as breaching clause 4.9.8 of the NER.
2. Being allocated a larger proportion of causer pays liabilities.

Moreover, some Generators' interpretation of clause S5.2.5.11(i)(4) as permitting them to turn the frequency responsiveness of their generating systems on and off, depending on whether they are providing a market ancillary service, does not assist AEMO in seeking to make more PFR available under normal operating conditions.

It is these issues that this rule change proposal seeks to address.

4.2.1 Causer pays arrangements

As discussed in Section 4.1.1, the lack of PFR within the NOFB is not assisted by clause 3.15.6A(k)(5)(i) and (7)(i) of the NER. Generators with scheduled and semi-scheduled generation are not assessed as being a 'causer' for Regulation FCAS if they follow their dispatch targets at a 'uniform rate'. This creates the impression that strictly following dispatch targets irrespective of frequency outcomes is ideal behaviour.

4.2.2 Strict compliance with dispatch instructions

Court proceedings initiated by the AER in 2014 and subsequent infringement notices issued to Generators for failure to comply with dispatch instructions[39] have created an intense compliance focus on clause 4.9.8(a) of the NER. This has resulted in Generators' altering their generating systems' frequency response deadbands to achieve stricter compliance with their dispatch instructions.

4.2.3 Misinterpretation of requirement to operate in frequency response mode

Compounding the lack of generator responsiveness to frequency variations, the recent amendment to clause S5.2.5.11(i)(4)[40] of the NER is being interpreted to to support (or require) Generators to effectively 'turn off' or otherwise override their generating systems' frequency response mode unless they are enabled for FCAS[41], notwithstanding the need for AEMO's approval as required by clause 4.9.4(e).

[39] The AER's "Enforcement Matters" webpage contains a number of articles detailing these actions: https://www.aer.gov.au/wholesale-markets/enforcement-matters.

[40] National Electricity Amendment (Generator technical performance standards) Rule 2018 No. 10. Available at: https://www.aemc.gov.au/sites/default/files/2018-09/Amending%20rule_1.pdf. See also Section 3.3.1 and Section 4.2 for a discussion of this change.

[41] Although clause 4.9.4(e) of the NER states that Generators must not change the frequency response mode of a scheduled generating unit without AEMO's approval (with limited exceptions), anecdotal evidence suggests that Generators are doing this and AEMO will never be certain of this without ongoing monitoring of generation output.

Although the AEMC commented in the Rule Determination that the revised provision should not be read as precluding frequency response mode operation at other times[42], it also stated:

> … the minimum access standard included in the final rule sets a very general requirement for generators to have a baseline frequency response mode capability. This basic **capability**[43] does not specify any specific kind of frequency control service, nor does it require any party to actually enter the markets for the provision of frequency control services.[44]

It is to be expected that participants (and manufacturers) will select plant settings to meet their performance standards and will not exceed those requirements or provide system benefits beyond those. Increasingly, the minimum performance requirements outlined in the NER are being used as engineering design guides.

If, as AEMO considers necessary, increased provision of PFR is to be facilitated under system normal conditions, clause S5.2.5.11(i)(4) would be inconsistent with that intent. To ensure that Generators seek AEMO's approval prior to changing their generating systems' operating mode, AEMO also proposes to make this provision subject to clause 4.9.4(e).

5. HOW THE PROPOSAL WILL ADDRESS THE ISSUE

5.1 Objectives

AEMO seeks to arrest the deterioration of frequency control under normal operating conditions as soon as possible by removing disincentives to the provision of PFR or clarifying rules that are contributing to the reduction in the provision of PFR. AEMO considers that these changes will:

- Facilitate the provision, or increased delivery, of PFR within the NOFB where Generators wish to do so.
- Reduce the likelihood of Generators changing their frequency response mode without AEMO approval by highlighting the existing NER requirement in clause 4.9.4(e).

5.2 Description of the proposed rule

A draft of the proposed rule is included as Appendix B. Compliance with dispatch targets

AEMO proposes to amend clauses 4.9.4 and 4.9.8 to clearly acknowledge that generation output will vary from dispatch targets when providing PFR. Importantly, clause 4.9.8 would be amended to clarify that, if generation deviates from its dispatch targets because it is assisting AEMO's control of power system frequency, the deviation will not be a breach of dispatch instructions. This should remove concerns around the provision of PFR resulting in non-compliance with dispatch targets.

5.2.1 Causer pays

A fundamental principle of the causer pays framework is that those Generators whose plant is not causing or exacerbating supply-demand mismatches should not be required to pay for Regulation FCAS. Clauses 3.15.6A(k)(5)(i) and 3.15.6A(k)(7)(i) of the NER deem that Generators do not contribute to frequency deviations if their plant achieves its dispatch targets at a uniform rate, but this is not necessarily helpful for frequency control. Control systems designed to ensure generating units track their dispatch targets without regard to changes in frequency can exacerbate the size of frequency deviations.

[42] See page 59, Rule Determination: National Electricity Amendment (Generator Technical Performance Standards) Rule 2018, dated 27 September 2018. Available at https://www.aemc.gov.au/sites/default/files/2018-09/Final%20Determination_0.pdf.

[43] Bolding added by AEMO.

[44] Page 57, Rule Determination: National Electricity Amendment (Generator Technical Performance Standards) Rule 2018, dated 27 September 2018. Available at https://www.aemc.gov.au/sites/default/files/2018-09/Final%20Determination_0.pdf.

For a range of reasons including its complexity, perceived aims, measurement and technical limitations, the causer pays mechanism appears to incentivise some Generators to track dispatch targets at a 'uniform rate' by removing PFR within the NOFB.

AEMO proposes to remove the provisions that suggest this will result in an automatic exclusion from causer pays liability in clause 3.15.6A(k)(5)(i) and 3.15.6A(k)(7)(i). These would be replaced with a provision that ensures no causer pays liability where a Generator's plant is providing PFR within parameters specified in AEMO's Regulation FCAS Contribution Factor Procedure (also commonly referred to as the causer pays procedure). This would remove a perceived disincentive to the provision of PFR and may incentivise its provision by allowing for the predictable avoidance of a cost that can be material for some Generators.

The proposed rule includes a requirement for AEMO to publish a list of the plant that is providing PFR consistent with the amended Regulation FCAS Contribution Factor Procedure. There is no intention of publishing any of the technical parameters at which that plant is operating. The purpose is to provide transparency in the number and identity of generating systems contributing to the improved control of power system frequency under normal operating conditions.

AEMO's proposed changes to the Regulation FCAS Contribution Factor Procedure[45] are described in Section 10. They are designed to align the current apparent incentive of minimising exposure to Regulation FCAS more closely with the stated causer pays objective in the NER to minimise the need for Regulation FCAS. If Generators with scheduled and semi-scheduled generating systems act in a way that minimises the need for Regulation FCAS, Regulation FCAS volumes would then reflect the underlying efficient volume still required for managing overall forecast and dispatch error within the market dispatch cycle.

5.2.2 Interpretation of requirement to operate in frequency response mode

Finally, AEMO proposes to amend clause S5.2.5.11(i) to clarify that generating systems may operate in frequency response mode at any time but, subject to clause 4.9.4(e), the only time they must be so operated is when they are providing a market ancillary service. This should ensure that Generators do not switch off their generating systems' frequency response mode when not providing FCAS only because they believe this is what the rule requires.

5.2.3 Transitional matters

Transitional rules are proposed to enable AEMO to update and publish the Regulation FCAS Contribution Factor Procedure to take account of the proposed rule contemporaneously with the rule change process.

5.3 Affected Generators

As shown in Figure 2, control of power system frequency under normal operating conditions has been declining slowly over many years, with a sharp decline starting from 2014-15.

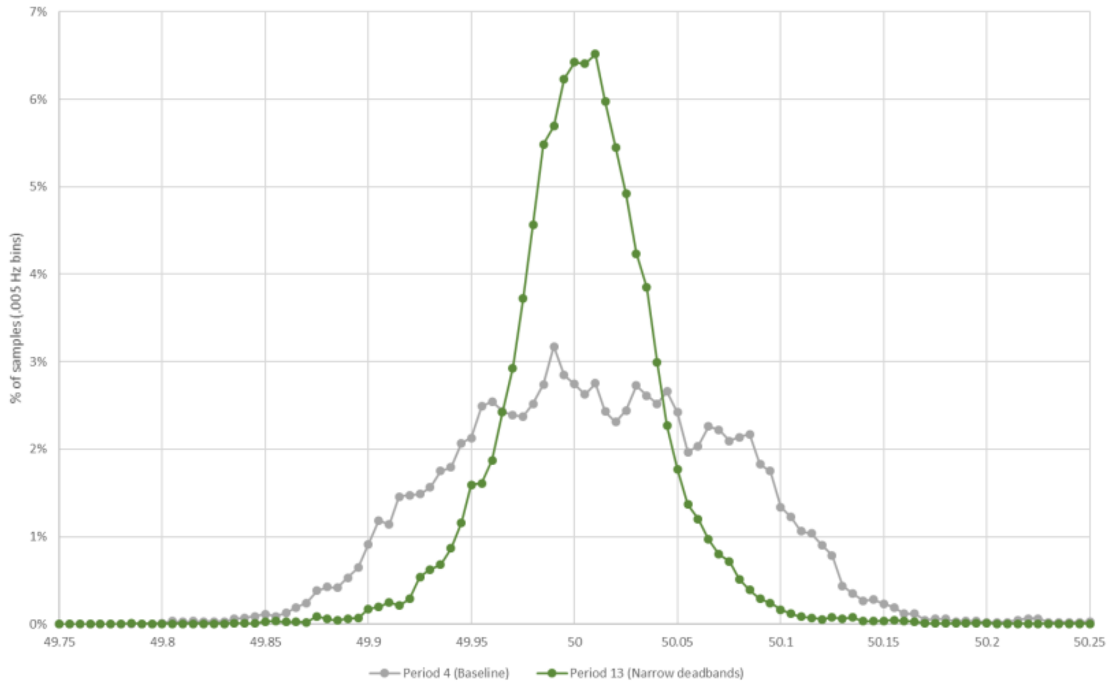
Although all Market Participants would potentially be affected by this proposal, the proposed rule does not create any new obligation on anyone to provide more PFR. Instead, it removes the disincentives to the provision of PFR noted by many Generators in feedback to DIgSILENT and AEMO. If a significant number of Generators choose to increase the provision of PFR as a result of the proposed rule, both NEM and international experience demonstrates that it would result in improved frequency control.

[45] AEMO is commencing a consultation under clause 8.9 of the NER following the submission of this rule change proposal. See http://aemo.com.au/Stakeholder-Consultation/Consultations.

5.3.1 Tasmania Frequency Control Trial

The results of the frequency response trial in Tasmania have been published by AEMO[46] and there was a clear improvement in frequency control after several generating units (approximately 30% of Tasmanian capacity) altered their deadband settings to zero. The results are shown graphically in Figure 11, but it should be noted that this impressive performance was achieved with near-zero wind generation.

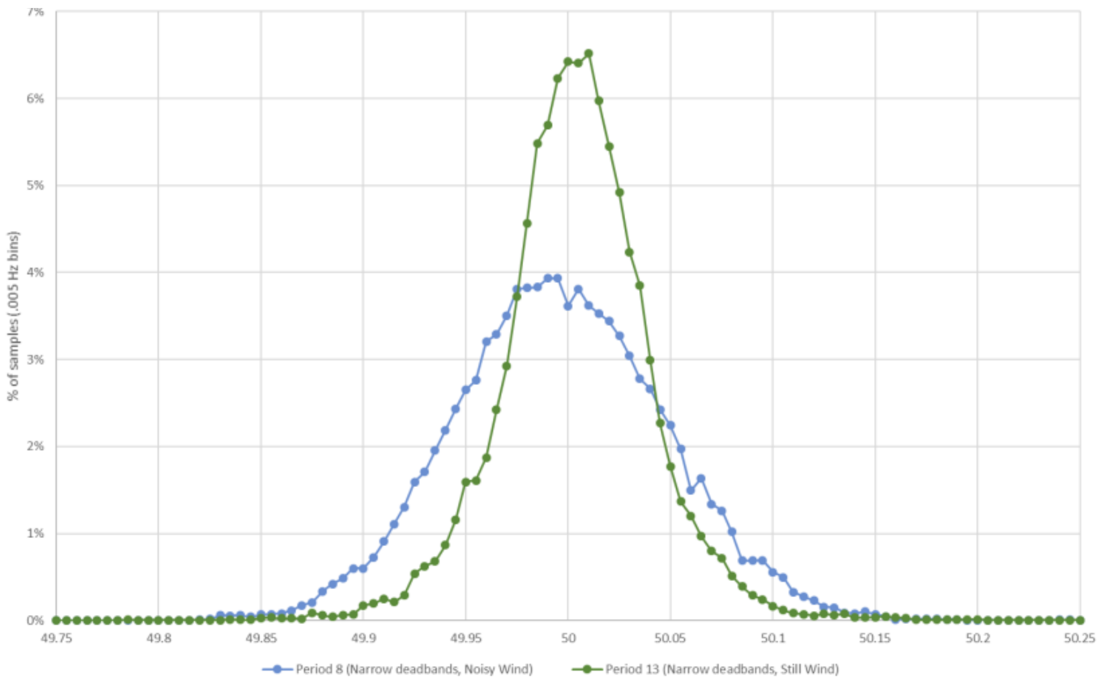
Figure 11 Baseline vs narrow frequency deadbands during Tasmania frequency control trial



Material variations in wind generation output under high wind conditions had a noticeable impact on frequency performance, as shown in Figure 12.

[46] Available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Frequency-Control/Trials/Tasmanian-Frequency-Control-Tests-Summary-Report.pdf.

Figure 12 Narrow frequency deadband performance (variable wind vs zero wind)



These results clearly indicate that better power system frequency performance can be achieved through the provision of more PFR from generating systems.

5.3.2 Texas PFR standard

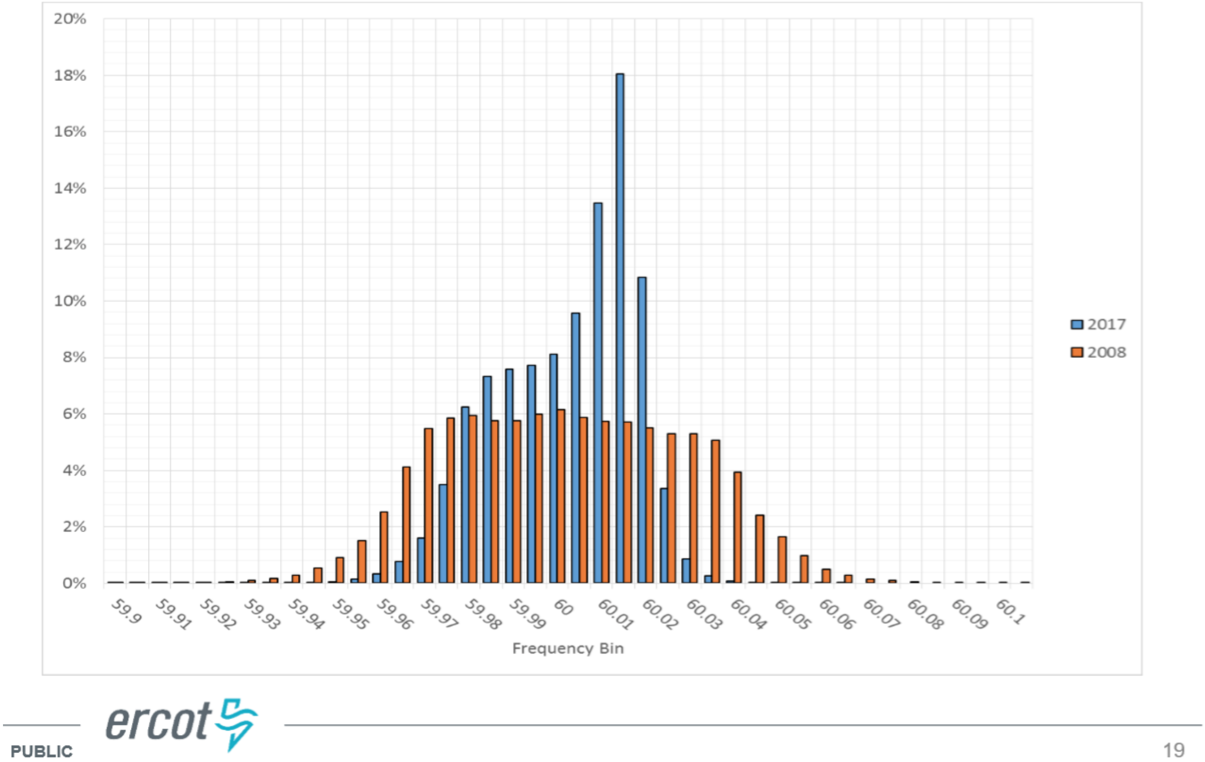
The Electric Reliability Council of Texas (ERCOT) operates the Texas Interconnection and has applied a regional standard for the provision of PFR since 2014, which requires PFR through mandated governor deadbands and droop settings.

PFR is expected within 1.5 seconds, with full response in 16 seconds, to be sustained for 1 hour.

ERCOT has published information on the improvement to its power system as a result of these measures. Figure 13 provides a snapshot of the improvement in power system frequency in Texas from 2008 to 2017[47].

[47] ERCOT, Presentation, Demonstration of PFR Improvement, September 2017. Available at: https://www.pjm.com/-/media/committees-groups/task-forces/pfrstf/20171009/20171009-item-04-ercot-frequency-response-improvements.ashx.

Figure 13 Comparison between 2008 and 2017 frequency profile



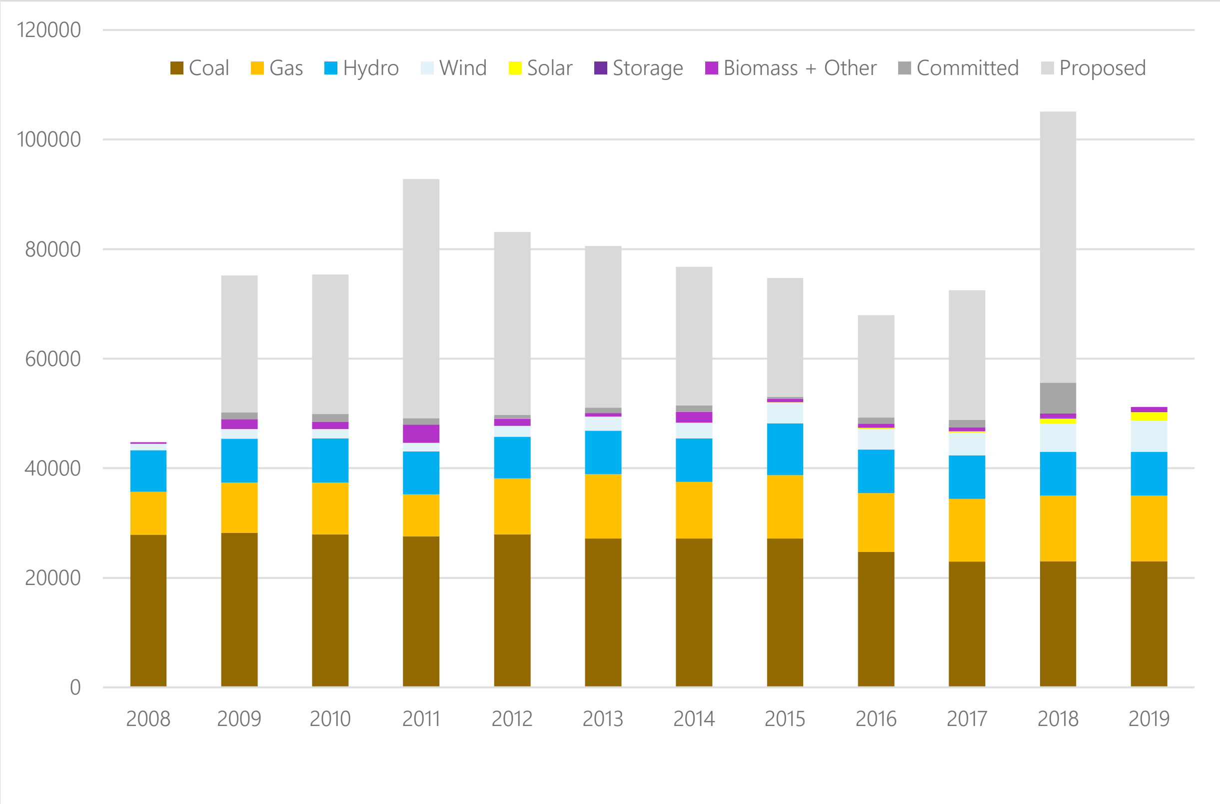
5.3.3 Optimal providers of PFR

The impact on the operation of the power system in the short term would be greatest if large synchronous generating systems increased their provision of PFR. This is because they typically are online for most of the time to provide PFR and typically have the largest MW response capability due to their larger size.

Historically, the NEM has been dominated by such large synchronous generation. Figure 14 shows that, while large synchronous generation has been losing its market share, it still dominates the mix of installed capacity across the NEM as a whole[48].

[48] The Electricity Statement of Opportunities for 2019 has yet to be published, so there is no update on the proposed and committed generation projects.

Figure 14 NEM generation mix by capacity (MW)

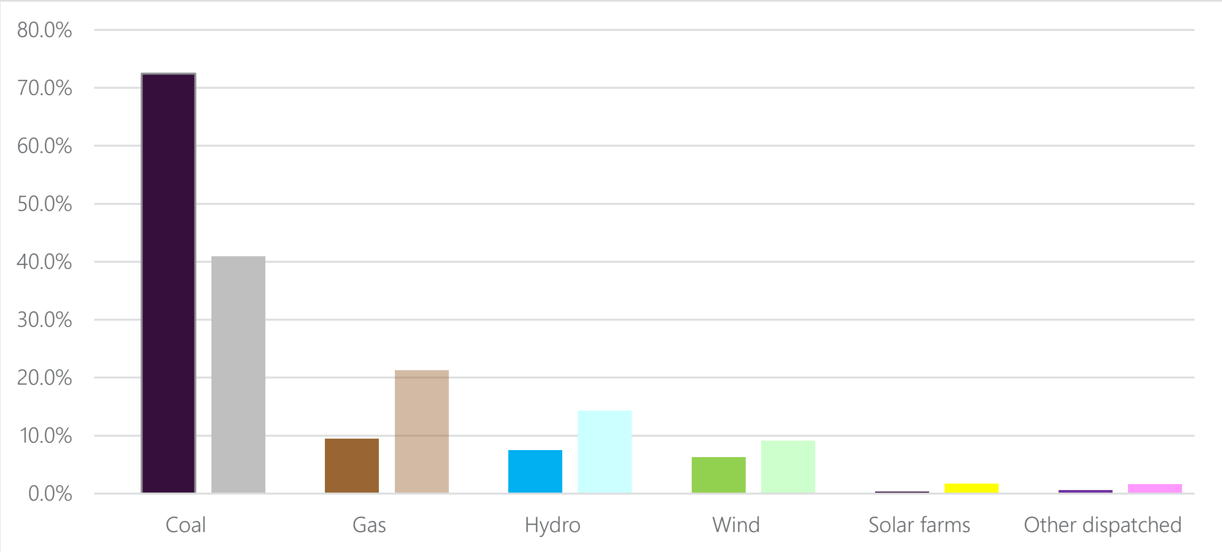


The dominance of large synchronous generation is starker when one compares the generation mix by output.

The 2018 State of the Energy Market Report by the AER depicts this for the 2017-2018 year as shown in Figure 15, as recalibrated by AEMO[49]. The light shaded columns represent relative capacity of each type of generation, while the darker columns represent the relative output from each type of generation. While intermittent generation has been steadily displacing large synchronous generation, when one considers the relative output of each type of generation, large synchronous generation still dominates by a healthy margin.

[49] Available at: https://www.aer.gov.au/publications/state-of-the-energy-market-reports. AEMO has combined the data for black coal and brown coal and not included rooftop solar, is it is not dispatched in the NEM.

Figure 15 NEM generation mix by output and capacity for 2017-2018



Therefore, the decline in power system frequency performance is largely attributable to the decline in the relative contribution of large synchronous generation towards the maintenance of power system frequency close to 50 Hz.

If there is still doubt as to the relative contribution made by large synchronous generation towards the maintenance of power system frequency, one should also consider the relative size of each power station, wind farm, or solar farm in the NEM. Table 4 shows the average size of each type of generating system.

Table 4 Average size of power stations and generating units in the NEM

Type	Power Station (approx. in MW)	Generating Unit (approx. in MW)
Coal	488	462
Gas	141	100
Hydro	127	43
Wind	91	3
Solar	48	3
Other	37	21

The proposed rule removes disincentives, (and, arguably, provides incentives through the avoidance of existing costs) for Generators to change their behaviour and to support the maintenance of power system frequency better than they have in the recent past.

Frequency control is degrading right now. To achieve different outcomes, the power system requires significant PFR from generation that was previously frequency-responsive. In the near term, that is most likely to come from existing large synchronous generation.

Nevertheless, any new arrangements must also consider a future in which renewable, inverter-connected generation will contribute an ever-increasing proportion of generation output in the NEM. The next large synchronous generating system scheduled to retire is Liddell Power Station in 2022, and ongoing closures of large synchronous generators are forecast to occur over the next two decades.

5.3.4 Generator survey results

Using the survey results referred to in Section 4.1.1, Table 5 quantifies the capacity of generation where PFR is currently available, or could be available in the NEM today, the bulk of which is synchronous thermal generation.

Table 5 Availability of PFR in the NEM

Region	Generation (MW)
NSW	12,154
QLD	9,296
VIC	5,254
SA	2,317.5
TAS	1,635[50]

From discussions with Generators operating renewable generating systems, it appears that a sizable proportion of semi-scheduled generation, particularly that installed more recently, can provide PFR, while the operators of some older plant might require an exemption on the basis that they lack the physical capability to provide it.

Therefore, the generating systems that could be readily made available to provide PFR comprise around 60% of the total scheduled and semi-scheduled generation capacity in the NEM. Therefore, significant volumes of additional PFR could be made available relatively quickly if Generators were required to do so.

6. COMPLEMENTARY ACTIONS BY AEMO

AEMO is undertaking several actions in conjunction with this rule change proposal that are material to frequency control, as detailed in the remainder of Section 6.

These changes are not expected to resolve the declining frequency performance in the NEM under normal operating conditions, either alone or in combination, but they are the only tools available to AEMO within the current regulatory framework, and may have some impact.

6.1 Reviewing Regulation FCAS volumes

Commencing in March 2019, AEMO has increased the base volumes of Regulation FCAS it procures for the mainland. AEMO has adopted a policy of increasing base volumes in small increments as required after approximately four-weekly reviews, and will occur on an ongoing basis, up to an initial maximum of 250 MW[51]. Monthly updates on the results of these changes now are being published on AEMO's website[52].

As the only tool currently available to AEMO to control frequency under normal operating conditions, increasing Regulation FCAS is an attempt to improve frequency control to the point where AEMO can again meet or exceed the requirements of the FOS under normal operating conditions.

Regulation FCAS is centrally controlled by AEMO through AGC and serves several purposes, including management of forecast errors, controlling time error, and slow correction of power system frequency. The overall design and purposes of AGC mean that it is not appropriate as the sole mechanism for correcting ongoing rapid movements in frequency within the NOFB, as discussed in Section 4.1.1.

Prior to 22 March 2019, the volumes of Regulation FCAS procured were 130 MW Regulation Raise and 120 Regulation Lower. Table 6 shows the increases made on a trial basis since that date:

Table 6 Increases in Regulation FCAS since 22 March 2019

Date	Increase	Percentage Increase	Total Procured
22 March 2019	50 MW	~ 38%	Regulation Raise 180 MW

[50] Based on outcomes of the trial in Tasmania.

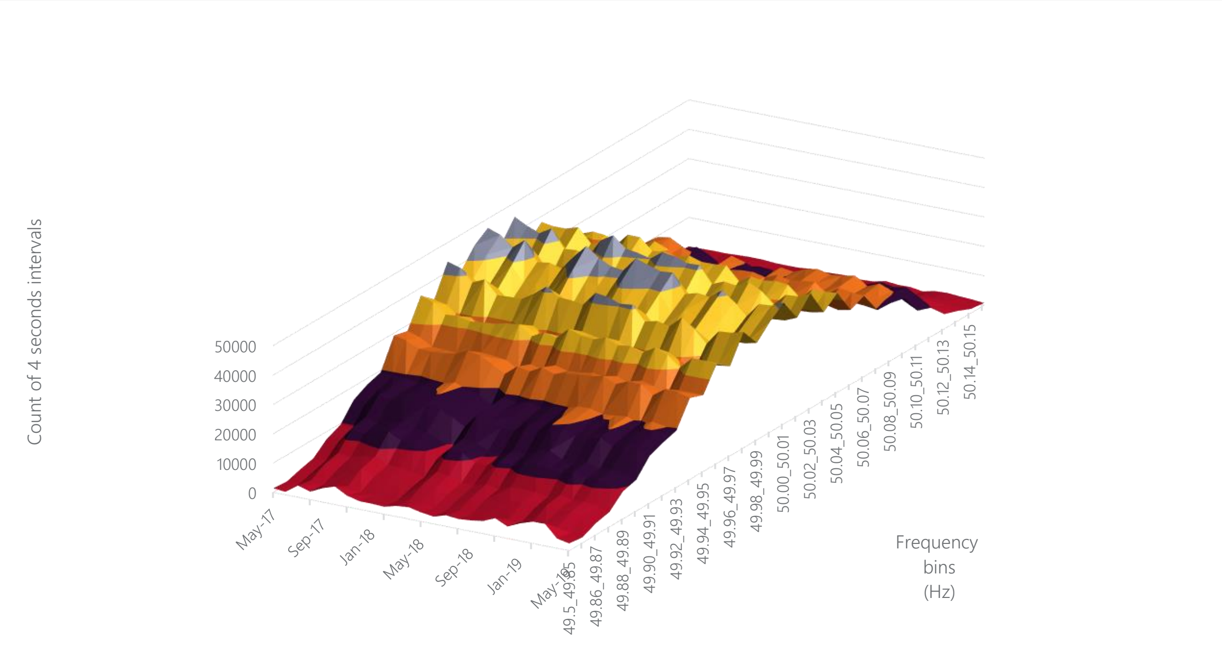
[51] See Regulation FCAS Changes, March 2019. Available at: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Frequency-and-time-error-reports/Regulation-FCAS-factsheet.pdf

[52] See Frequency and Time Deviation Monitoring, April 2019. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Frequency-and-time-error-monitoring

			Regulation Lower 170 MW
23 April 2019	20 MW	~ 53%	Regulation Raise 200 MW Regulation Lower 190 MW
23 May 2019	20 MW	~ 69%	Regulation Raise 220 MW Regulation Lower 210 MW

The outcomes of these increases are shown in Figure 16.

Figure 16 Frequency distribution within the NOFB for the last 12 months



An aggregate increase of around 70% in the base volume of Regulation FCAS procured[53] has not improved the distribution of frequency within the NOFB. The chart indicates a further reduction in frequencies closest to 50 Hz. At best, it can be observed that power system frequency is not exiting the NOFB as frequently. Even so, two months of increased Regulation FCAS is insufficient to conclude whether any real benefits have been gained or that they are sustainable.

6.2 Regional allocation of Regulation FCAS

AEMO is considering the implementation of a maximum cap on the volume of Regulation FCAS that can be procured from each region, which is intended to ensure geographic diversity in the delivery of this response.

As Regulation FCAS is continuously utilised during normal operation of the power system, its over-allocation to any one region in the NEM will have an ongoing impact on network flows in and around that region. Geographic dispersal will reduce the impact of its ongoing utilisation on network flows, particularly interconnectors, resulting in more stable operation of the power system.

[53] Factsheets available at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Frequency-and-time-error-monitoring.

6.3 Review and regional allocation of Contingency FCAS volumes

AEMO has commenced a review of the volumes of Contingency FCAS being procured. The key factors that may affect volumes are the assumed load relief, and the response of distributed energy resources to disturbances.

Obtaining rigorous data to underpin any changes is challenging, and very large numbers of constraint equation changes would be required if there were to be changes to these assumptions. This is resulting in a longer timeframe for this review than for Regulation FCAS volumes.

AEMO is also considering whether there is a need for geographic diversity in the sources of Contingency FCAS, similar to the approach being considered for Regulation FCAS.

6.4 Further review of AGC performance

As noted in Section 2.5, AEMO is reviewing AGC performance again after having it tuned last year and expects this to be completed by the end of 2019.

The purpose of this review is to ensure optimal usage of the Regulation FCAS procured.

6.5 Disincentives in the MASS

The way AEMO measures the provision of Contingency FCAS, as specified in the MASS, incentivises the delayed delivery of PFR until power system frequency crosses the edge of the NOFB.

It is not in the interests of power system performance to encourage Generators to delay or withhold delivery of PFR following a disturbance because an earlier delivery will reduce the frequency deviation that occurs following a contingency event. AEMO proposes to address it separately outside this rule change proposal.

7. FREQUENCY OPERATING STANDARD

A potential solution to arrest the deterioration of frequency performance in the NEM is to make the frequency requirements in the FOS more stringent. The FOS is a standard that AEMO is expected to meet, but it can only do so using the limited range of tools at its disposal.

It is becoming increasingly challenging to meet certain of the FOS requirements already, therefore, amending the FOS to tighten the requirements on AEMO will only cause AEMO to breach them more often until new tools become available.

As noted in Section 6.1, procuring more Regulation FCAS might address AEMO's inability to meet the FOS but is unable to arrest the deterioration of power system frequency control within the NOFB.

At this stage, neither tightening the FOS requirements, nor procuring more Regulation FCAS will address the underlying issue, which is the declining frequency control under normal operating conditions due to the identified disincentives and misinterpretation of requirements that are having the effect of reducing the provision of more PFR from existing generation.

8. STAKEHOLDER ENGAGEMENT

Prior to submission of this rule change proposal, AEMO met with all the Generators with large generation portfolios in the NEM, and some with smaller generation, to discuss this rule change proposal. These

Generators covered all generation technologies currently used in the NEM. AEMO also met with large consumers and small consumer representatives as well as industry representative bodies.

These meetings were held to take initial feedback on the underlying frequency control issue and this rule change proposal. It should be noted that AEMO also sought feedback on a separate proposal to introduce mandatory PFR requirements in the NEM, and the responses summarised below also comment on that.

8.1.1 Generators

Generators provided a range of responses on the causes and consequences of the decline in PFR, as well as the potential solutions:

Concern with current state of power system

- Some Generators operating large synchronous generating units expressed concern about the level of ongoing frequency changes now observed on the power system. They noted it was difficult to quantify the exact costs and risks of these changes, but that the level of frequency variation was making stable operation of their plant more difficult. Some reported increased difficulty and delays in synchronising their generating units.
- One expressed concerns about the increased long-term risk of asset failures.
- Some considered that the power system's response on 25 August 2018 was broadly as expected, and that AEMO's focus on PFR is not warranted. In other words, UFLS and OFGS operated as designed, system standards were broadly met, and so there was no need for improvement.
- Many advised that control changes have been made to reduce to ongoing response of their own generating units to the deteriorating control of frequency under normal conditions.
- Some advised that control changes have been made in an attempt to reduce their exposure to recovery of Regulation FCAS costs. Different Generators had different experiences in reducing this exposure, and a range of views were expressed on the appropriate control strategies.

Compliance with dispatch instructions as a disincentive to providing PFR

- Many raised dispatch compliance as an important consideration. There was concern that any increased provision of PFR carried a risk of being assessed as non-compliant with dispatch instructions.

Exposure to Regulation FCAS costs as a disincentive to providing PFR

- Some Generators with larger portfolios suggested recovery of Regulation FCAS costs is a relatively small overall consideration for them. Any potential reduction of causer pays liability was insufficient to incentivise changed behaviour, or to compensate/offset the uncertain risks that could arise in providing increased PFR.
- Some expressed concerns about allowing Generators operating renewable generation to reduce or avoid exposure to the recovery of Regulation FCAS costs, given that they are often understood to be capable of providing PFR in one direction only – namely, to rising power system frequency.
- Generators with solar PV plant expressed interest in providing PFR to avoid exposure to Regulation FCAS costs. This included the potential use of overload capability in their plant to provide PFR. This capability often exists due to the additional inverter MVA and PV panel DC MW capacity installed both to ensure MW output can be maintained at reduced connection point voltages, and to lengthen the time of day when full output can be achieved. This capability could be used to increase connection point MW output in response to declining frequency, above current connection point MW limits and would offset any reduction in yield due to reducing output in response to high frequency.

No support unless paid to provide PFR

- Generators did not support any requirement for unpaid PFR and suggested that any increased provision of PFR should be incentivised by a new revenue stream.

First mover disadvantage as a disincentive to provide PFR

- Some were supportive of a mandatory PFR requirement, particularly if the performance expected from all Generators was clear, as current regulatory and market arrangements were seen as convoluted, and hard to understand and translate into actual performance requirements
- Many Generators expressed concerns about the consequences of being one of only a few to provide PFR within the NOFB. They saw this as creating an unfair and undue operational burden on their own generating units. Some advised that a mechanism was required to ensure a critical volume of generation provided PFR inside the NOFB, to ensure minimum impact on any single generating unit.
- Some Generators with large plant expressed cautious support for provision of increased PFR within the NOFB, at least on a trial basis, from some, but not all, of their generating units, if the previously noted risks could be addressed.

Miscellaneous barriers to provision of PFR

- Some raised concerns around compliance with their performance standards and modelling requirements for their generation.
- Some Generators with wind generation advised their plant was fundamentally incapable of providing PFR, and that they would seek to be exempted from any requirement to provide it. One advised that their plant was not negatively affected by current power system frequency performance, and they did not believe a case had been made as to why it should be improved.
- One raised an issue about their power purchase agreements (PPAs), including those with the Victorian government under the VRET Scheme, might restrict their ability to provide PFR as the PPAs require them to maximise the generation their plant can produce unless mandated by the NER to do otherwise, such as by the application of constraint equations.

Ease of modifying plant to provide PFR

- Some Generators with synchronous generating units advised that, as a matter of practicality, they expected it would be relatively straightforward to modify relevant control system settings, such as frequency response deadbands, or whether they were to be operated in frequency response mode.
- One wished to seek advice from its equipment manufacturer before making any changes.

Generators were also asked whether they would be prepared to alter their generating systems to provide additional PFR if the proposed rule were made, and there were diverse views:

- Generators with renewable generation were very keen to explore how they could modify their plant to be more frequency-responsive and minimise their exposure to causer pays liabilities.
- Some Generators with large synchronous generation were prepared to assist by offering some additional PFR even though there was little financial incentive, provided they were not exposed to the risk of being found in breach not meeting their dispatch targets.
- Some were not inclined to do anything unless accompanied by a new revenue stream.

8.1.2 Consumers

Meetings were also held with large and small customer representatives to brief them and seek feedback on the proposed changes.

- Major industrial load customers stressed the undesirability of supply interruption, except where no other options were available.
- One noted that the resilience of their loads to supply interruption has reduced since they were originally commissioned.
- Some major customers identified causer pays exposure as an important, and unpredictable cost impact for their business. One advised they were participating in some of the FCAS markets, which provided a valuable income stream, and they were assessing their ability to participate in more FCAS markets.

8.1.3 Others

- Industry representative bodies largely reflected the comments of their members, namely that Generators should be paid to provide more PFR if, in fact, that was what the power system needed.
- Small customer representatives were focussed on the cost impacts of these proposals. They understood that the current proposals would not directly alter total market costs for FCAS but would instead alter the distribution of how these costs were recovered.

9. NON-CONTROVERSIAL RULE CHANGE

AEMO requests that this rule change proposal be treated as a 'non-controversial rule' under section 96 of the National Electricity Law (NEL). The reasons why AEMO considers this is appropriate are outlined further in Section 10.

9.1 Rule-Making Process

Section 87 of the NEL defines 'non-controversial rule' as follows:

> ***non-controversial Rule*** means a Rule that is unlikely to have a significant effect on the national electricity market.

Section 2 of the NEL defines the 'national electricity market' as follows:

> ***national electricity market*** means—
>
> (a) the wholesale exchange operated and administered by AEMO under this Law and the Rules; and
>
> (b) the national electricity system;

Hence, the proposed rule must be unlikely to have a significant effect on both the wholesale exchange and the power system, with the key terms being 'unlikely' and 'significant'. These terms must be considered in context.

9.2 Clarifications only

AEMO submits that the proposed rule is comprised of clarifications to existing provisions in the NER.

Nothing in the proposed rule creates new obligations on Registered Participants:

- The changes to Chapter 3 remove perceived disincentives to the provision of PFR under normal operating conditions and are consistent with the underlying principle that Market Participants who operate their plant to minimise the need for Regulation FCAS should be rewarded by not having to pay for Regulation FCAS procured while they are providing PFR.
- The changes to Chapter 4 ensure that what appears to be implicit in the NER is made explicit, by referring to frequency support when dealing with compliance with dispatch instructions. While the

issue of dispatch compliance has a controversial history, the proposed rule seeks to remove any argument that a literal reading of these provisions prevents Generators from supporting power system frequency. It will be clear that Generators with frequency-responsive plant who support AEMO's control of power system frequency will not be non-compliant with their dispatch instructions.

- The changes to Chapter 5 will remove any perception by Generators that they are expected to disable their generating plant's frequency response mode when not providing market ancillary services.

By removing these disincentives to the provision of PFR, the proposed rule will enable Generators to participate in any future mainland frequency trial, or to trial the provision of PFR for other reasons, for example to assess the impact on their causer pays outcomes.

The only new obligations created by the proposed rule are on AEMO:

- AEMO is to undertake consultation on an amended Regulation FCAS Contribution Factor Procedure[54] to incorporate the changes proposed.
- AEMO will publish the identity of the power stations providing PFR in accordance with a specification in the Regulation FCAS Contribution Factor Procedure.

9.3 Application of non-controversial test

The proposed rule meets the non-controversial test in the NEL because:

- It clarifies existing rules to achieve intended outcomes. Existing rules have given rise to perverse outcomes and the proposed rule corrects misinterpretations and misapplications.
- The term 'unlikely' in section 87 of the NEL relates to the probability that something will occur. In the context of the proposed rule, nothing will change unless Generators determine that there is a financial benefit to them in changing their operating behaviour. Hence, the proposed rule, of itself, does not result in any change.

  Second, based on AEMO's informal consultation with Generators on this rule change proposal,[55] it was clear that the Generators who expressed interest in providing PFR because of the potential benefit of receiving smaller causer pays liabilities were those with smaller, asynchronous renewable generation.

  As depicted in Figure 15, smaller, renewable generation represents less than 10% of dispatched generation in the NEM. On the assumption that some of those Generators might be constrained from providing significant PFR by commercial arrangements in their PPAs, it seems that removal of the disincentives in the proposed rule will only result in limited change in Generator behaviour.

  Discussions with Generators on the provision of more PFR were not as positive, but there was some interest in assisting in the control of frequency under normal operating conditions if the identified disincentives could be addressed.

- The term 'significant' in section 87 of the NEL needs to be considered in relation to both the wholesale market and the power system.

  When considering those who would be motivated financially to provide PFR, AEMO's discussions with Generators show that only some would do so, those operating smaller, renewable generation.

  In the context of the power system, the proposed rule could only have a significant (positive) effect only if a substantial number of Generators determine to provide PFR, an outcome considered unlikely

[54] Available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Regulation-FCAS-Contribution-Factors-Procedure.pdf.

[55] See the discussion in Section 8.

unless sufficient numbers of large generating units make simultaneous adjustments to avoid the 'first mover disadvantage' discussed in Section 8.1.1.

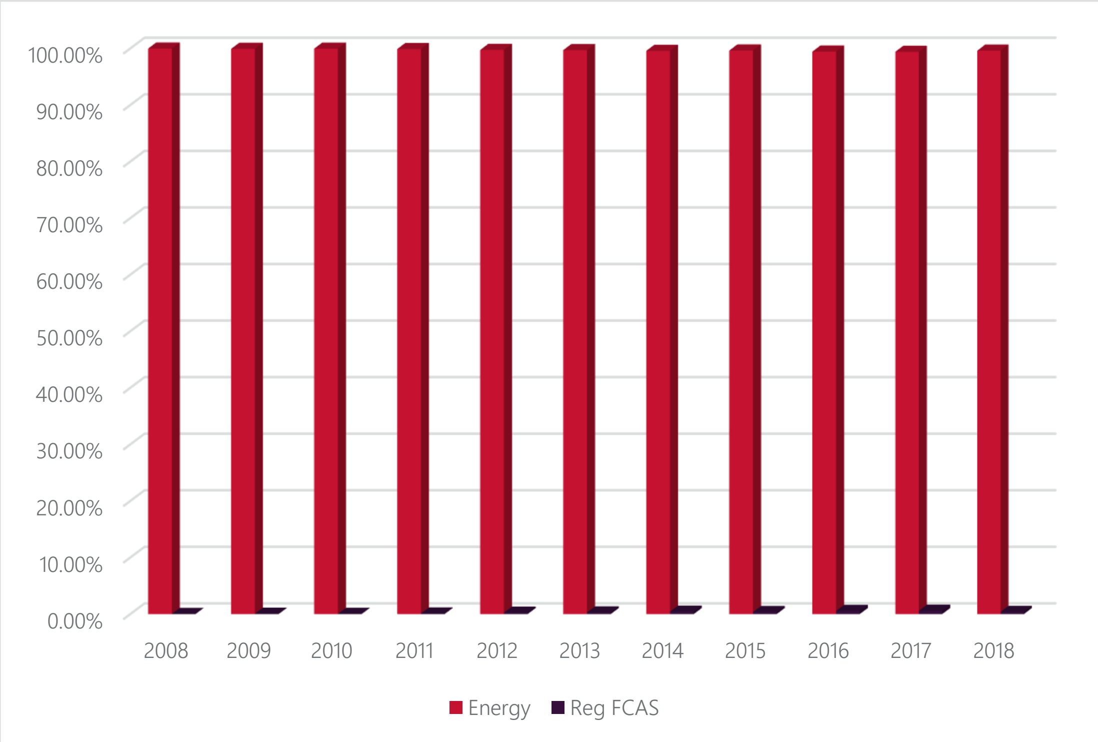
- AEMO understands that the reason why Generators with smaller, renewable generation might be likely to provide PFR is because their profitability is likely to be enhanced more significantly than it would be for Generators with large synchronous generation. The impact of the proposed rule on a Market Participant, however, or class of Market Participant, is not a relevant consideration in determining whether the proposed rule would have a significant effect on the NEM.

  In this instance, the impact would be merely a transfer of wealth represented by the redistribution of Regulation FCAS costs between Market Participants.

  The total cost of Regulation FCAS in 2018 was around \$62 million. When compared against the total energy purchased in the NEM during FY 2017-18, which was around \$16.1 billion[56], the cost of Regulation FCAS is around 0.4% of the total energy purchased, a very small proportion of the total value of energy traded in the NEM.

  This is not significant and has not been significant even after the steep rise in Regulation FCAS costs shown in Figure 8. Figure 17 depicts the sharp contrast between the cost of energy versus Regulation FCAS. The highest it has ever been is about 0.6%, which occurred during 2016-17.

Figure 17 Comparison of the relative cost of Regulation FCAS vs energy traded in the NEM



This is a very small proportion of the total value of services traded in the NEM, and AEMO submits that the impact on the NEM of the proposed rule would not be significant even if all Regulation FCAS costs were redistributed.

The Tasmanian trial demonstrated that more PFR under normal operating conditions can go a long way towards improving power system frequency performance, and so AEMO considers that the provision of

[56] Sourced from the AEMO Annual Report 2018. Available at: http://aemo.com.au/-/media/Files/About_AEMO/Annual-Report/AEMO-Annual-Report-2018.pdf.

more PFR from generation in the NEM should improve frequency performance. In the context of the non-controversial test, however, the proposed rule is unlikely to have a significant effect on the NEM.

10. PROPOSED CAUSER PAYS PROCEDURE CHANGES

10.1 Need for PFR deadband

To implement the proposed causer pays changes it will be necessary for the Regulation FCAS Contribution Factor Procedure to specify a deadband outside of which PFR must be provided to be assessed as not contributing to the need for Regulation FCAS.

The setting of this deadband will affect both the distribution of power system frequency achieved inside the NOFB, and the ongoing impact on generation of achieving this frequency distribution. The experience of the Tasmanian frequency trials in May 2018 clearly demonstrated the key role that changing frequency response deadbands played in changing power system frequency outcomes.

The FOS does not provide guidance on the technical outcomes that must be achieved, as they effectively allow any distribution of frequency to occur under normal operating conditions, so long as 99% of the time it remains within ±0.150 Hz around 50 Hz.

Simplified simulation models have been described[57], which can indicate the relationship between:

- Ongoing short-term underlying statistical variation in the total load (sometimes referred to as 'nett load sizzle') which, in turn, affects the net mismatch between load and generation.
- Total system aggregate PFR from all generation to the resulting frequency changes for different levels of frequency response deadband, and generation response capabilities.
- Both the response of the power system to contingency events, and the ongoing system frequency distribution for undisturbed conditions.

The output of such models are entirely a reflection of their input assumptions, in particular, the level of ongoing net load short term changes ('nett load sizzle'), which in the NEM is unknown, as is the current aggregate response of generation for small changes (in part due to a lack of underlying certainty or co-ordination of generator PFR response obligations).

AEMO is not aware of any power system where PFR requirements for normal operating conditions have been derived analytically using such simulation models, or in a similar manner.

It can be stated with certainty, however, that to reliably achieve any distribution of frequency entirely within any given band, frequency deadbands smaller than that band are required. Prior to establishment of the FCAS markets in 2001, the maximum allowable generator deadband specification (±0.050 Hz) was set at half the required NOFB at the time (±0.100 Hz).

10.2 Proposed deadband requirement

This lack of clarity around the required outcomes and the impacts on plant has resulted in AEMO's proposal of a PFR deadband of ±0.050 Hz in the Regulation FCAS Contribution Factor Procedure. Operation of generation at this level (or lower) would be voluntary but would ensure no exposure to recovery of Regulation FCAS costs.

[57] For example, see section 12 of Primary Frequency Response and Control of Power System Frequency. 2018 by Undrill, John. LBNL-2001105.

This value is consistent with the frequency response deadband requirements in the NEM prior to establishment of the FCAS markets, which was based on Australian utility practice prior to establishment of the NEM. The period prior to 2001 was associated with significantly better control of frequency under normal operating conditions.

A significant fraction of the generation capacity in the NEM was constructed and commissioned to be consistent with those requirements and is expected to be capable of operating with a deadband setting of ±0.050 Hz, or narrower.

To minimise the initial impact on plant of providing PFR, a wider deadband of ±0.075 Hz is being proposed for the first 6 months after publication of the amended Regulation FCAS Contribution Factor Procedure. This is still within the ±0.100 Hz deadband setting that some generating systems are operating with for delivery of certain Contingency FCAS, but not so narrow as to cause a large change in operational impact for any plant that moves to this initial setting.

Experience gained with the effects of operating with these different frequency deadband settings, both on the power system and on generating systems, would be invaluable for determining the long-term requirements for achieving a level of improved frequency control under normal operating conditions, particularly if this was ultimately to be codified via a change to the FOS under normal operating conditions.

11. EXPECTED BENEFITS AND COSTS OF THE PROPOSED RULE

11.1 Costs of doing nothing

The highest cost of doing nothing is the cost of a major supply disruption that could have been avoided or minimised if the power system had improved frequency control.

In its report, DIgSILENT identified several other consequences associated with doing nothing, which means permitting frequency performance to continue to deteriorate[58]. Most of these were either possible or almost certain, and they include:

- Increased wear and tear on plant due to increasing movement caused by greater frequency deviations.
- Reduction in the efficiency of generation due to changes in output as a result of deteriorating frequency regulation and increased governor response.
- Potential need for additional Contingency FCAS to maintain power system security considering the increase in power system frequency volatility.
- Increase in Regulation FCAS costs without a commensurate benefit.
- Further withdrawal of PFR due to the added burden on the remaining Generators providing PFR.

11.2 Costs of proposed rule

AEMO reiterates that the proposed rule does not create an obligation on a Generator to provide PFR. It merely removes disincentives to its provision.

Generators who do not provide PFR under normal operating conditions are not expected to incur additional operating costs as a result of the actions of others who elect to do so.

[58] See page 49.

The proposed rule could result in reduced recovery of Regulation FCAS costs from any Generators who elect to provide PFR within the NOFB. If that occurs, there will be a redistribution in the recovery of Regulation FCAS costs towards Market Customers, and some Generators who don't provide PFR.

The expected costs of the proposed rule for Generators who increase provision of PFR would vary, but can be summarised as follows:

11.2.1 Upfront costs of changes to plant controls

AEMO notes that some Generators will incur costs to change their plant controls to provide PFR, however, for some Generators, these costs are minimal, in particular where their plant has previously operated to provide PFR within the NOFB.

The voluntary nature of the provision of PFR means that no Generator is compelled to make any changes. It is expected that those for whom the costs or too high will not do so.

11.2.2 Increase in fuel consumption

Some Generators have suggested that there are costs associated with the increase in fuel consumption if they were to provide PFR under normal operating conditions. These costs are estimated by one Generator at 0.5% of fuel cost[59], however, actual costs will be extremely dependent on factors such as the deadband adopted, amount of active PFR in the power system, technology type and fuel type.

11.2.3 Impact on FCAS markets

Hypothesised impacts on the FCAS markets noted by various stakeholders are:

- Reduction in the volume of Regulation FCAS procured.
- Reduction in the assessed provision of Contingency FCAS because generation will be frequency responsive sooner than the edge of the NOFB.
- Reduction in the volume of Contingency FCAS procured.

Each of these is addressed in turn.

Impact on Regulation FCAS

As Figure 8 shows, the cost of the ancillary services markets, especially Regulation FCAS, has been increasing while frequency performance has been deteriorating. AEMO has recently increased the volume of Regulation FCAS it procures in an attempt to improve the control of frequency under normal operating conditions. This is expected to result in increases in Regulation FCAS costs without a commensurate benefit, and early indications are that this will not improve AEMO's ability to control frequency to be as close as practicable to 50 Hz.

On the other hand, the increased delivery of PFR under normal operating conditions should ultimately result in the operation of the NEM with the most efficient level of Regulation FCAS, which could result in less Regulation FCAS to control power system frequency.

In power systems with significant levels of PFR close to 50 Hz, a key purpose of secondary frequency control reserves, such as Regulation FCAS, is to enable the return of all generating systems that have deviated from their dispatch targets to provide PFR back to their dispatch targets, by replacing the missing MW initially corrected by the provision of PFR. There will be an ongoing need for Regulation FCAS for this purpose.

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[59] Noted by DIgSILENT in its report on page 42.

Impact on Contingency FCAS

Some stakeholders have noted that an increase in the delivery of PFR within the NOFB could reduce the need for Contingency FCAS. The requirement for Contingency FCAS, however, is dictated by the size of the contingency events considered and managed via this market arrangement, and these are not dependent on the amount of available PFR.

Also of note is that a Generator providing PFR within the NOFB may deliver part of the headroom it holds for the purpose of delivering Contingency FCAS during smaller frequency deviations, and may therefore be assessed as delivering less MW response after frequency has left the NOFB, which is the response considered in FCAS markets. This concern can be specific to the design of a generating system's frequency response. This concern would be addressed by amending the MASS appropriately to recognise the delivery of PFR inside of the NOFB.

11.3 Potential benefits of proposed rule

The proposed rule creates an environment where Generators might be incentivised to increase the provision of PFR under normal operating conditions.

The potential benefits of the proposed rule can be summarised as follows:

11.3.1 No increase in costs to consumers

The proposed rule is not expected to directly increase costs to consumers.

The total cost of Regulation FCAS in 2018 was around $62 million. When compared against the total energy purchased in the NEM during FY 2017-18, which was around $16.1 billion[60], one can see that the cost of Regulation FCAS is around 0.4% of the total energy purchased, a very small proportion of the total value of energy traded in the NEM.

If accepted, the proposed rule will lead to a redistribution of causer pays liabilities as between Market Participants based on their relative contribution to the need for Regulation FCAS, which is, after all, the purpose of the framework for the recovery of Regulation FCAS as stipulated in clause 3.15.6A(k)(1) of the NER. Increased provision of PFR may allow for a reduction in the volume of Regulation FCAS required, and would assist in driving Regulation FCAS volumes towards a more efficient level.

11.3.2 Increase in power system resilience

Disturbances on the power system are inevitable, but greater PFR (both within, and outside, the NOFB) will increase the power system's resilience to such events. This, in turn, is likely to assist AEMO in managing the size of their impact, which is expected to be less if frequency is close to 50Hz, than if it were bouncing between the extremities of the NOFB. For example, more stable control of frequency under normal operating conditions:

- maximises the frequency change that must occur before emergency responses, such as OFGS or UFLS, occur and allows more time and a more stable environment for other corrective responses to occur; and
- should reduce the likelihood of load shedding being required by ensuring the greatest frequency margin is available before load shedding commences, and the earliest commencement of the provision of PFR to arrest and correct a disturbance.

[60] Sourced from the AEMO Annual Report 2018. Available at: http://aemo.com.au/-/media/Files/About_AEMO/Annual-Report/AEMO-Annual-Report-2018.pdf.

11.3.3 More accurate measure of supply-demand balance

A power system's frequency should serve as a reliable indicator of the supply-demand balance in real-time to enable a wide range of automatic control systems to respond appropriately.

The increasing ongoing, rapid and poorly controlled movement of frequency under normal operating conditions reduces the utility of frequency as a signal to indicate whether supply and demand are closely matched, and the appropriate response that control systems should take in response.

11.3.4 Unnecessary activation of triggered frequency response

One of the consequences of not having as accurate a measure of the supply-demand balance is the unnecessary activation of control and protection systems.

Some Contingency FCAS is provided by frequency-triggered interruption of load, or frequency-triggered automatic start, synchronisation and loading of fast start generation. Improved control of frequency under normal operating conditions would minimise unnecessary triggering of these services caused by slightly wider than normal variation of frequency.

Contingency FCAS is intended to respond to contingency events, particularly the sudden loss of one or more major generating units, and the frequent activation, particularly of contracted load interruption in response to increasingly 'normal' drifting of frequency, can be increasingly disruptive and inconvenient for Contingency FCAS providers.

This more frequent activation creates an incentive for these switched FCAS providers to take action. The actions they could take include:

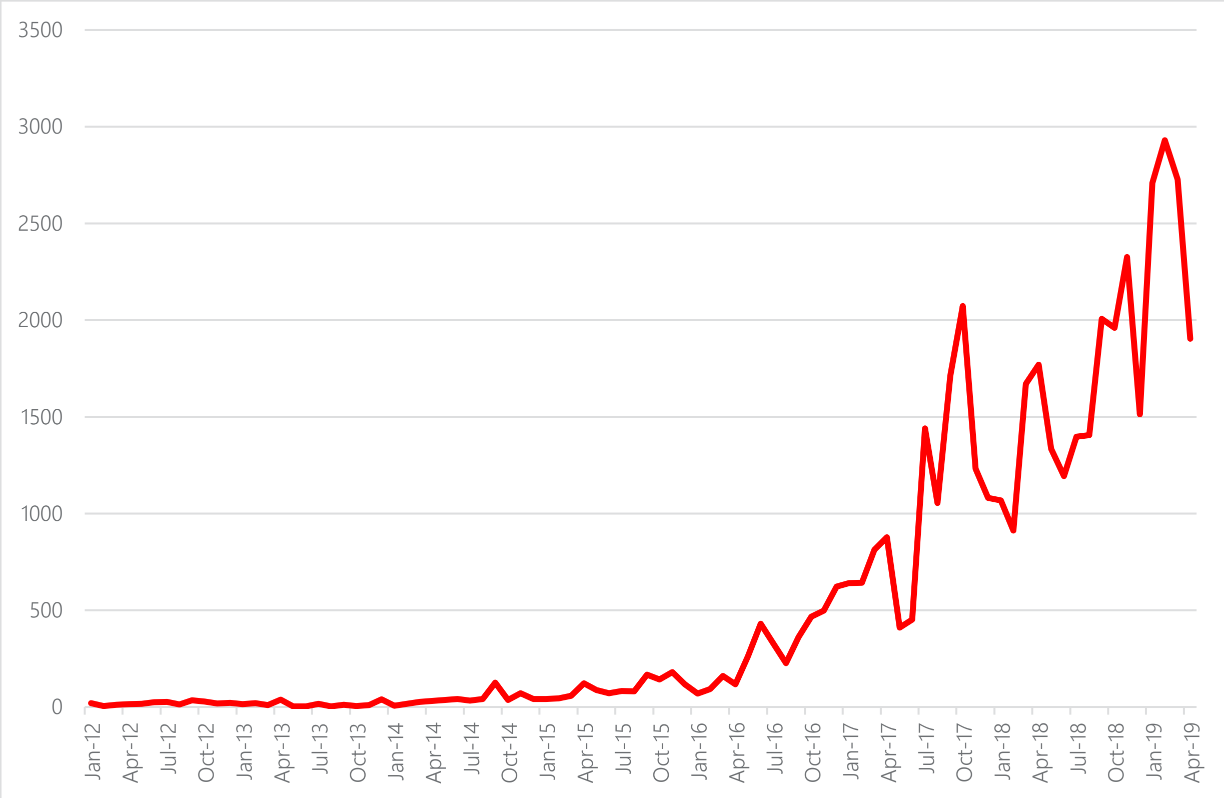
- widening their frequency response bands to reduce the occurrence of their activation, and/or adjusting other settings to reduce the amount of response from the facility, which reduces both their technical effectiveness and their value as Contingency FCAS.
- increasing the cost of their Contingency FCAS offers to reflect the increased potential usage.
- limiting participation in the Contingency FCAS markets, which reduces competition.

Figure 18 clearly shows that the percentage of time that frequency in the mainland is outside the NOFB is increasing.

Figure 18 shows that the number of discrete instances of frequency departing the NOFB has been increasing, mirroring the deterioration in frequency performance, suggesting that the risk that any frequency disturbance could occur while power system frequency is already outside the NOFB is increasing rapidly. The decline in April 2019 shows that the recent increase in the procurement of Regulation FCAS[61] has made a difference, but it is still significantly higher than it was three years ago.

[61] See section 6.1 for details.

Figure 18 Number of frequency events outside the NOFB (Jan 2012 to Apr 2019)



11.3.5 Synchronising of plant

Some Generators have reported increasing difficulties and delays in synchronising their generating units to the power system due to the increasing movement of frequency under normal operating conditions.

International standards require synchronous generation to be designed to synchronise without damage to a frequency difference of ±0.067 Hz[62]. Where frequency is drifting more than this, as it routinely does in the NEM, longer times to synchronise can reasonably be expected, which represents lost opportunities for those seeking to sell their electricity through the NEM.

The ability to synchronise and load fast start plant rapidly and reliably will likely become increasingly valuable to operators of this generation once 5-minute settlement is introduced on 1 July 2021[63].

The operational flexibility offered to the NEM by these fast start generating systems is expected to become increasingly important as the proportion of total energy supplied by weather-driven generation increases. The ability to start and synchronise rapidly and reliably will become increasingly important for efficient market operation, which would be supported by more stable control of power system frequency.

11.3.6 Wear and tear on plant

Some Generators have expressed concern about the increase in wear and tear on plant attempting to correct frequency deviations in the present environment.

62 IEEE Std C50.12-2005: Salient-Pole 50 Hz and 60 Hz Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications Rated 5 MVA and above, and IEEE C50.13-2014: Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and above. Available at: https://ieeexplore.ieee.org/document/1597614.

63 See National Electricity Amendment (Five Minute Settlement) Rule 2017 No. 15. Available at: https://www.aemc.gov.au/sites/default/files/2018-07/ERC0201%20note%20and%20amending%20rule.pdf

If more generating systems provide PFR because of the proposed rule, any wear and tear impact on each of them will decrease. It is when only a few generating systems are providing PFR that those few will, literally, be doing the heavy lifting and exposing their plant to greater wear and tear.

As noted in Section 5.2, the proposed rule will assist in converting the existing vicious cycles of generator behaviour into virtuous cycles.

11.4 Balancing the costs and benefits of the proposed rule

AEMO submits that the parts of the national electricity objective that are relevant to this rule change proposal are the efficient investment in, and efficient operation and use of, electricity services with respect to the price and the reliability of supply because:

- Frequency is a vital aspect of power system operation that directly affects the reliability of the power system when it is not in balance and can affect the supply of electricity to consumers. AEMO's reduced ability to control power system frequency following major disturbances to the power system through PFR means that AEMO must rely more on emergency schemes for controlling frequency, such UFLS and OFGS.
- The complementary measures AEMO described earlier are only expected to have marginal impact but are the only measures that AEMO can take in the absence of the proposed rule.

As noted in Section 6.1, the impact of the increase in Regulation FCAS, to date, appears to be that it can keep frequency closer to the extremities of the NOFB but cannot hold it closer to 50 Hz.

AEMO submits that the proposed rule meets the rule-making test because:

- The AEMC has previously stated that 'a reliable power system is a crucial part of the energy market and the long-term interest of consumers'[64]. AEMO is unable to achieve any real improvement in the control of power system frequency under normal operating conditions using the current tools available to it under the NER. AEMO notes that the AEMC has previously considered the extent of potential changes underway in the NEM and the ability of current frameworks to adapt and address the consequences of those changes as a relevant consideration[65]. The AEMC has made changes to the NER where it was likely that continuing with existing arrangements would not be in the long-term interests of consumers. Having UFLS as the only tool to control under-frequency has far more economic impact than the solution that the proposed rule provides. PFR will minimise the risk that UFLS will be used.
- The potential for more PFR facilitated by the proposed rule coupled with better information about the actual level of PFR will also improve the usefulness of planning for contingencies, and a more efficient planning process will benefit consumers by facilitating better decisions by AEMO to improve the efficient operation of the NEM. A better understanding of how the power system will perform under a range of conditions would facilitate more efficient operation of the power system and procurement of appropriate levels of FCAS, as well as how the power system will react to contingencies.
- The proposed rule merely creates a framework under which Generators can volunteer to provide PFR with no compensation other than a reduction in their exposure to Regulation FCAS costs. As a consequence, AEMO contends that the costs to be incurred by these Generators would not exceed the benefits to be gained and, as noted in Section 11.3.1, because the proposed rule will not result in

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[64] See page 31, Rule Determination, National Electricity Amendment (Enhancement to the Reliability and Emergency Reserve Trader) Rule 2019, 2 May 2019. Available at: https://www.aemc.gov.au/sites/default/files/2019-05/Final%20Determination.pdf.

[65] See page 16, Rule Determination, National Electricity Amendment (Emergency frequency control schemes) Rule 2017, 30 March 2017. Available at: https://www.aemc.gov.au/sites/default/files/content/5dad7625-02cd-4b3b-b52d-b70d1b2609ea/Emergency-frequency-control-schemes-Final-rule-determination-%28FINAL-PU.pdf.

any cost increases to consumers, either now or the longer term, the benefits of the proposed rule will always exceed the costs.

11.5 Comparison of costs and benefits with and without proposed rule

The costs of doing nothing are greater than the costs of the proposed rule and conversely, the benefits are less. Table 9 summarises the costs associated with the proposed rule and compares them against the costs of not making the proposed rule.

Table 7 Comparison of costs and benefits associated with proposed rule against the costs of doing nothing

Issue	Proposed rule	No rule change
Changes to plant controls	Minor cost as provision of PFR is voluntary.	Nil
Fuel consumption	Minor cost as provision of PFR is voluntary.	No guarantee that additional fuel will not be consumed as frequency will continue to deteriorate. Increased Regulation FCAS will also consume more fuel.
Wear and tear	Decreasing costs as more generating systems provide PFR.	Increasing in cost as more generating system disable their frequency responsiveness due to deteriorating frequency.
Regulation FCAS	Potential cost decrease if only the minimum efficient volumes of Regulation FCAS are needed.	Increase in cost as more Regulation FCAS is being procured from 22 March 2019.
Contingency FCAS	No or minimal impacts; Contingency FCAS volumes unaffected.	The proposed rule will have no impact on the volume of Contingency FCAS that needs to be procured. Changes to the MASS to recognise PFR delivered inside the NOFB may be justified to allay concerns of under-delivery due to measurement assumptions in the MASS.
Impact on consumers	No or minimal increase in costs.	Greater cost as more Regulation FCAS is being procured and as the power system remains more vulnerable to disruption due to poor frequency control.
Frequency activated automated protection systems	Better utilisation, and lower incidence of false or unnecessary triggers, leading to lower costs associated with contingencies.	Increase in risk of false activations disrupting power system and market operations and consequent costs associated with false contingencies.
Supply-demand balance	More PFR will ensure supply-demand balance restored most efficiently and effectively, resulting in less cost associated with contingencies being larger due to ineffective frequency control.	AGC will constantly chase frequency, resulting in the ineffective and inappropriate use of Regulation FCAS at a high cost.
Synchronisation	Generation will be able to synchronise to the power system more quickly, allowing more efficient market operation	Generation will continue to take more time than is necessary to connect to the power system resulting in increasing costs that are passed through to the consumer.

APPENDIX A. GLOSSARY

This proposal uses many terms that are defined in the NER and are intended to have the same meanings. Common abbreviations for terms and measures are set out below:

Abbreviation/Term	Term/Meaning
AEMC Final Report	The AEMC's Final Report: Frequency Control Frameworks Review, dated 26 July 2018.
AEMO Incident Report	AEMO Final Report: Queensland and South Australia system separation on 25 August 2018. An operating incident report for the National Electricity Market, 10 January 2019.
AER	Australian Energy Regulator
AGC	*Automatic generation control*
causer pays	The principle underlying the NER framework for recovering the costs payable to Regulation FCAS providers. It requires determination of the extent to which suitably metered market generating systems or loads have contributed to the need for regulation frequency control.
Contingency FCAS	*Fast raise service*, *fast lower service*, *slow raise service*, *slow lower service*, *delayed raise service*, and *delayed lower service*.
Contingency Lower FCAS	*Fast lower service*, *slow lower service* and *delayed lower service*
ENTSO-E	European Network of Transmission System Operators for Electricity
ERCOT	Electric Reliability Council of Texas
FCAS	*Frequency* control *ancillary service*
FOS	*Frequency operating standard*
Generator	*Generator*
kV	kiloVolt (1,000 Volts)
MASS	*Market ancillary service specification*
MW	MegaWatt (1,000,000 Watts)
NEM	National Electricity Market
NER	National Electricity Rules
NOFB	*Normal operational frequency band*
NSW	New South Wales
OFGS	Over-*frequency* generator shedding
PFR	Primary frequency response
PPA	Power purchase agreement
PV	Photovoltaic
QLD	Queensland
QNI	QLD–NSW interconnector
Regulation FCAS	*Regulating raise service* and *regulating lower service*.
SA	South Australia
SCADA	Supervisory control and data acquisition.
TAS	Tasmania
TNSP	*Transmission network service provider*
UFLS	Under-*frequency load shedding*
VIC	Victoria

APPENDIX B. DRAFT RULE

This draft is based on version 121 of the National Electricity Rules.

PROPOSED CHANGES TO CHAPTER 3

3.15.6A Ancillary service transactions

....

(k) *AEMO* must prepare a procedure for determining contribution factors for use in paragraph (j) and, where *AEMO* considers it appropriate, for use in paragraph (nb), taking into account the following principles:

(1) the contribution factor for a *Market Participant* should reflect the extent to which the *Market Participant* contributed to the need for *regulation services*;

(2) the contribution factor for all *Market Customers* that do not have *metering* to allow their individual contribution to the aggregate need for *regulation services* to be assessed must be equal;

(3) for the purpose of paragraph (j)(2), the contribution factor determined for a group of *regions* for all *Market Customers* that do not have *metering* to allow the individual contribution of that *Market Customer* to the aggregate need for *regulation services* to be assessed, must be divided between *regions* in proportion to the total customer energy for the *regions*;

(4) the individual *Market Participant's* contribution to the aggregate need for *regulation services* will be determined over a period of time to be determined by *AEMO*;

(5) a *Market* ~~*Registered*~~ *Participant* ~~which has classified a *scheduled generating unit*, *scheduled load*, *ancillary service generating unit* or *ancillary service load* (called a **Scheduled Participant**)~~ will not be assessed as contributing to the deviation in the *frequency* of the *power system* if, within a *dispatch interval*, its *plant*:

(i) ~~the Scheduled Participant achieves its *dispatch* target at a uniform rate;~~[deleted]

(ii) ~~the Scheduled Participant~~ is *enabled* to provide a *market ancillary service* and responds to a control signal from *AEMO* to *AEMO's* satisfaction; or

(iii) ~~the Scheduled Participant~~ is ~~not *enabled* to provide a *market ancillary service*, but~~ operating in *frequency response mode* in accordance with one or more parameters specified in the procedure and responds to arrest the *frequency* deviation ~~to *AEMO's* satisfaction responds to a need for *regulation services* in a way which tends to reduce the aggregate deviation~~;

(6) where contributions are aggregated for *regions* that are operating asynchronously during the calculation period under paragraph (i), the contribution factors should be normalised so that the total contributions from any non-synchronised *region* ~~or *regions*~~ is in the same proportion as the total customer energy for that *region* ~~or *regions*~~; ~~and~~

(7) [deleted]~~a *Semi-Scheduled Generator* will not be assessed as contributing to the deviation in the *frequency* of the *power system* if within a *dispatch interval*, the *semi-scheduled generating unit*:~~

~~(i) achieves its *dispatch* target at a uniform rate;~~

~~(ii) is *enabled* to provide a *market ancillary service* and responds to a control signal from *AEMO* to *AEMO's* satisfaction; or~~

~~(iii) is not *enabled* to provide a *market ancillary service*, but responds to a need for *regulation services*.~~

...

(nc) *AEMO* must maintain and publish on its website a list of *plant* being operated in the manner contemplated by paragraph (k)(5)(iii).

PROPOSED CHANGES TO CHAPTER 4

4.9.4 Dispatch related limitations on Scheduled Generators and Semi-Scheduled Generators

A *Scheduled Generator* or *Semi-Scheduled Generator* (as the case may be) must not, unless in the *Generator's* reasonable opinion, public safety would otherwise be threatened or there would be a material risk of damaging equipment or the environment:

(a) send out any *energy* from a~~the~~ *generating unit*, except:

(1) in accordance with a *dispatch instruction*;

(2) in response to remote control signals given by *AEMO* or its agent;

(3) in connection with a test conducted in accordance with the requirements of this Chapter or Chapter 5;

(3A) as a consequence of its operation in *frequency response mode* to adjust *power system frequency* in response to *power system conditions*; or

(4) in the case of a *scheduled generating unit*~~:~~,

~~(i)~~ in accordance with the *self-commitment* procedures specified in clause 4.9.6 up to the *self-dispatch level*; ~~or~~

~~(ii) as a consequence of operation of the *generating unit's* automatic *frequency response mode* to *power system* conditions;~~

…

4.9.8 General responsibilities of Registered Participants

(a) A *Registered Participant* must comply with a *dispatch instruction* given to it by *AEMO* unless to do so would, in the *Registered Participant's* reasonable opinion, be a hazard to public safety or materially risk damaging equipment.

(a1) A *Scheduled Generator* or *Semi-Scheduled Generator* is not taken to have failed to comply with a *dispatch instruction* as a consequence of the operation of a *generating unit* in *frequency response mode* to adjust *power system frequency* in response to *power system conditions*.

PROPOSED CHANGES TO CHAPTER 5

S5.2.5.11 Frequency control

…

(i) For the purposes of subparagraph (b)(2), and with respect to a *negotiated access standard* proposed for the technical requirements relevant to this clause S5.2.5.11:

…

(4) subject to clause 4.9.4(e), a *generating system* may ~~is required to~~ operate in *frequency response* mode at any time, but must operate in *frequency response mode* ~~only~~ when it is enabled for the provision of a relevant *market ancillary service*; and

…

CHAPTER 11 – New Part

Part ZZZX Primary frequency response under normal operating conditions

11.1XX Rules consequential on the making of the National Electricity Amendment (Removal of disincentives to the provision of primary frequency response under normal operating conditions) Rule 2018

11.1XX.1 Definitions

For the purposes of this rule 11.1XX:

Amending Rule means the *National Electricity Amendment (Removal of disincentives to the provision of primary frequency response under normal operating conditions) Rule* 2019.

commencement date means [date].

11.1XX.3 Amendment to contribution factor procedure

(a) *AEMO* must, in accordance with clause 3.15.6A(m), amend and *publish* the procedure for determining contribution factors under clause 3.15.6A(k), as required, to take into account the Amending Rule to apply from the commencement date.

(b) If, prior to the commencement date and for the purposes of developing changes to the procedures referred to in paragraph (a) in anticipation of the Amending Rule, *AEMO* undertook consultation or a step equivalent to that required in the *Rules consultation procedures*, that consultation or step is taken to satisfy the equivalent consultation or step under the *Rules consultation procedures*.