INTERIM PRIMARY FREQUENCY RESPONSE REQUIREMENTS

REPORT AND DETERMINATION

Published: 1 **June 2020**

EXECUTIVE SUMMARY

This Report and Determination (Report) finalises the consultation conducted by AEMO to make and publish the interim Primary Frequency Response Requirements (IPFRR) under clause 11.122.2(a) of the National Electricity Rules (NER).

AEMO released an early draft of the proposed Primary Frequency Response Requirements with its rule change proposal ERC0274 Mandatory primary frequency response and updated it during the AEMC's consultation on that proposal. AEMO updated the document again before commencing this consultation on 1 April 2020[1].

AEMO also held three forums with Generators and one meeting with Australian Energy Council members to discuss the latest draft and respond to concerns and thirteen submissions were received, some late, for AEMO's further consideration. Overall, there were fourteen major issues raised, with a variety of minor issues and five other issues AEMO has highlighted in this Report.

Major changes made to the IPFRR as a result of submissions received during this consultation are:

1. AEMO has provided more detail on how Affected Generators should operate their Affected GS in each market AEMO operates.
2. AEMO has clarified that Affected Generators are to ensure that their Affected GS can meet the PFR settings at the connection point. How Affected Generators adjust their Affected GS to achieve those outcomes is at their discretion.
3. AEMO has restructured the document to specify standing variations to the operation of Affected GS to acknowledge that there are many reasons affecting different technologies that could impact on the provision of PFR at any given time, eliminating the need for ad hoc variations for common limitations on the provision of PFR.
4. The Self-Assessment process and documentation have been updated and clarified to assist AEMO's processing and grouping of Affected GS by ability and timing to be ready to provide PFR.
5. Consultation with Affected Generators following receipt of Self-Assessment results to co-ordinate changes is more prominent.
6. AEMO has provided more information to assist Affected Generators who might be seeking an exemption or variation and aligned the principles with the PFR Rule and clarified that they are free to reapply if circumstances change or more information comes to light.
7. It is now clearer that there are alternative ways to demonstrate plant stability, not just by way of step response test.
8. AEMO has clarified that it will not conduct additional compliance monitoring specifically for the IPFRR. Potential non-compliances will be investigated if there is evidence indicating that an Affected GS is being operated contrary to its approved PFR settings.
9. Affected Generators granted an exemption or variation will have the option of consenting to the publication of additional details of the reason for exemption or the varied parameter values.
10. AEMO has included an indicative implementation timetable, noting that it will be updated following receipt of the Self-Assessment results and published separately on AEMO's website.

After considering the submissions received, AEMO's determination is to make the interim Primary Frequency Response Requirements in the form published with this Report.

[1] Although commencing after publication of the National Electricity Amendment (Mandatory primary frequency response) Rule 2020 No. 5, the consultation documents were finalised prior to its publication.

CONTENTS

1. STAKEHOLDER CONSULTATION PROCESS

As required by clause 11.122.2(a) of the National Electricity Rules (NER), AEMO has consulted on the interim Primary Frequency Response Requirements.

AEMO's timeline for this consultation is outlined below.

Deliverable	Date
Notice of consultation published	1 April 2020
Submissions closed	8 May 2020
Final Report published	01 June 2020

A glossary of terms used in this Draft Report can be found at Appendix A.

2. BACKGROUND

2.1. Context for this consultation

The National Electricity Amendment (Mandatory primary frequency response) Rule 2020 No. 5 commences on 4 June 2020 (PFR Rule). Its purpose is to introduce a mandatory requirement on all Scheduled Generators and Semi-Scheduled Generators to make their generating systems responsive to changes in power system frequency so as to provide primary frequency response (PFR) to assist AEMO achieve the following outcomes:

- Re-establish effective control of power system frequency, and thereby align the NEM with standard international practice.
- Increase the resilience of the power system to disturbances, particularly events beyond simple credible contingency events.
- Ensure a predictable frequency response from generation to power system disturbances, to support power system planning and modelling.

The key instrument in determining how and when Scheduled Generators and Semi-Scheduled Generators are to make these changes and how exemptions and variations from these requirements will be managed by AEMO, is the Primary Frequency Response Requirements (PFRR).

Clause 4.4.2A(a) of the NER states:

(a) *AEMO* must develop, publish on its website and maintain, the *Primary Frequency Response Requirements* in accordance with the *Rules consultation procedures*.

The transitional rules provide for an interim version to be made under clause 11.122.2, which requires AEMO to publish interim Primary Frequency Response Requirements (IPFRR) in accordance with an abridged consultation process. Clause 11.122.2(a) & (b) states:

(a) *AEMO* must develop, publish on its website and maintain interim Primary Frequency Response Requirements by 4 June 2020 to apply until the *Primary Frequency Response Requirements* are made and published under paragraph (d).

(b) AEMO is not required to comply with the *Rules consultation procedures* when making the interim Primary Frequency Response Requirements under paragraph (a) but must publish a draft of the interim Primary Frequency Response Requirements on its website by 9 April 2020 and provide at least 20 business days for written submissions from any person on this draft.

The requirements the IPFRR is required to meet are stated in clause 11.222.2(c):

(c) The interim Primary Frequency Response Requirements must:

(1) take into account any submissions on the draft of the interim Primary Frequency Response Requirements received under paragraph (b);

(2) include the matters to be included in the *Primary Frequency Response Requirements* under new clause 4.4.2A(b); and

(3) set out the process for the coordinated activation of changes to *generating systems*, including the date (which may vary according to *plant* type) by which *Scheduled Generators* and *Semi-Scheduled Generators* must effect changes to their *plant*, to comply with the Interim Primary Frequency Response Requirements.

The requirements the PFRR must meet are in clause 4.4.2A(b) and (c), which are:

(b) The *Primary Frequency Response Requirements* must include:

(1) a requirement that *Scheduled Generators* and *Semi-Scheduled Generators* set their *generating systems* to operate in *frequency response mode* within one or more performance parameters (which may be specific to different types of *plant*), which:

(i) must include maximum allowable deadbands which must not be narrower than the *primary frequency control band* outside of which *Scheduled Generators* and *Semi-Scheduled Generators* must provide *primary frequency response*; and

(ii) may include (but are not limited to):

(A) droop; and

(B) response time,

(the *primary frequency response parameters*);

(2) subject to rule 4.4.2B, the conditions or criteria on which a *Scheduled Generator* or *Semi-Scheduled Generator* may request, and *AEMO* may approve, a variation to, or exemption from, any *primary frequency response parameters* applicable to its *scheduled generating system* or *semi-scheduled generating system*;

(3) the process and timing for an application for a variation to, or exemption from, any *primary frequency response parameters* applicable to a *scheduled generating system* or *semi-scheduled generating system*, and the process for approval by *AEMO* of such variation or exemption; and

(4) details of the information to be provided by *Scheduled Generators* and *Semi-Scheduled Generators* to verify compliance with the *Primary Frequency Response Requirements* and any compliance audits or tests to be conducted by *AEMO*.

(c) The *Primary Frequency Response Requirements* must not require a *Scheduled Generator* or *Semi-Scheduled Generator* to:

(1) maintain stored energy in its *generating system* for the purposes of satisfying clause 4.4.2(c1); or

(2) install or modify monitoring equipment to monitor and record the *primary frequency response* of its *generating system* to changes in the *frequency* of the *power system* for the purpose of verifying the *Scheduled Generator's* or *Semi-Scheduled Generator's* compliance with clause 4.4.2(c1).

Clause 4.4.2B(a) details the principles AEMO must have regard to when considering whether to approve an application for an exemption or variation. It states:

(a) In considering whether to approve an exemption from, or a variation to, any of the *primary frequency response parameters* applicable to a *Scheduled Generator's* or *Semi-Scheduled Generator's generating system*, *AEMO* must have regard to:

(1) the capability of the *generating system* to operate in *frequency response mode*;

(2) the stability of the *generating system* when operating in *frequency response mode*, and the potential impact this may have on *power system security*;

(3) any other physical characteristics of the *generating system* which may affect its ability to operate in *frequency response mode*, including (but not limited to) *dispatch inflexibility profile*, operating requirements, or *energy constraints*; and

(4) whether the *Scheduled Generator* or *Semi-Scheduled Generator* has been able to establish to *AEMO's* reasonable satisfaction that the implementation of the *primary frequency response parameters* applicable to that *Scheduled Generator's* or *Semi-Scheduled Generator's generating system* will be unreasonably onerous having regard to (among other things):

(i) the likely costs of modifying the *generating system* to be able to operate in *frequency response mode*; and

(ii) the likely operation and maintenance costs of operating the *generating system* in *frequency response mode*, relative to the revenue earned from the provision of *energy* and *market ancillary services* by the *generating system* in relation to its operation in the *NEM* during the 12 months prior to the date of the application for exemption or variation, as applicable.

2.2. Consultation

AEMO issued a Notice of Consultation and published a draft of the IPFRR on its website on 1 April 2020. Submissions were originally due on 30 April 2020, however, during the forums, AEMO extended the due date to 8 May 2020.

AEMO received thirteen written submissions.

At the request of the Australian Energy Council (AEC), AEMO convened a videoconference with the AEC on 20 April 2020, which was also attended by representatives of several industry participants, including, to AEMO's knowledge:

Alinta Energy	CS Energy	Delta Electricity
Engie	Horizon Power	Hydro Tasmania
Infigen Energy	InterGen	Origin Energy
Snowy Hydro	Stanwell Corporation	

AEMO also organised four forums, each focussed on a different type of generation technology, so as to ensure that Generators with diverse concerns could receive an equal opportunity to have their issues heard.

Table 1 details the dates of each forum and all known organisations represented. All forums were held by videoconference.

Table 1 Forum Attendees

Date	Focus	Company/Organisation
22 April 2020	Coal and gas generation	AEMC
		AGL
		Alinta Energy
		CS Energy
		Delta Electricity
		ERM Power
		Horizon Power
		InterGen
		Origin Energy
		Stanwell Corporation
23 April 2020	Hydro generation, consultants and Network Service Providers	AEMC
		AGL

		CQ Partners
		Energy Queensland
		Hydro Tasmania
		Jacobs
		Snowy Hydro
		Stanwell Corporation
29 April 2020	Wind and solar generation and battery systems	AEMC
		AGL
		Alinta Energy
		APA Group
		CleanCo Qld
		Enel Green Power
		Enel X
		Impact Investment Group
		Innogy Renewables Australia
		Meridian Energy
		NEOEN
		Tesla
		Tilt Renewables
		Total Eren
		Windlab
		X-Elio

Copies of submissions have been published on AEMO's website at https://aemo.com.au/consultations/current-and-closed-consultations/primary-frequency-response-requirements-document-consultation, while notes of discussions, and issues raised in forums (excluding any *confidential information*) have been published at: https://aemo.com.au/initiatives/major-programs/primary-frequency-response.

Many forum attendees sought clarification on various aspects of the IPFRR and the notes follow a question-and-answer format. Only material issues are addressed in this document.

3. SUMMARY OF MATERIAL ISSUES

While most Consulted Persons structured their submissions by reference to the sections of the IPFRR, many of them in fact raised broader issues. This report is, therefore, generally structured thematically, rather than by reference to a particular section of the IPFRR.

The key material issues arising from the proposal and raised by Consulted Persons are summarised in Table 2.

Table 2 Material Issues

Reference	Issue	Raised by
4.1	Requirement to provide PFR	Forum of 20, 22 & 29 April 2020 Infigen Energy Stanwell
4.2	Allowable deadband	Forum of 20 & 22 April 2020 CS Energy Delta Electricity ERM Power Infigen Energy Hydro Tasmania
4.3	Whether all Affected GS should be operating with the same deadband	Forum of 29 April 2020
4.4	Operating with a wider deadband	Forum of 20, 22 & 29 April 2020 AGL Energy Clean Energy Council Delta Electricity Tilt Renewables
4.5	The use of P_{MAX} as a reference point for droop control	Forum of 22, 23 & 29 April 2020 AGL Energy Clean Energy Council Edify Energy Origin Energy Tilt Renewables
4.6	Limitations on the delivery of PFR	Forum of 20, 22, 23 & 29 April 2020 CS Energy Delta Electricity ERM Power Origin Energy Stanwell
4.7	Exemption and variation criteria	AGL Energy CS Energy ERM Power Infigen Energy
Error! Reference source not found.	Usurpation of FCAS markets	Forum of 20 & 22 April 2020 CS Energy Delta Electricity ERM Power
Error! Reference source not found.	Impact on generator performance standards (GPS)	Forum of 20, 22 & 29 April 2020 AGL Energy Vestas
4.10	Alternatives to step response tests	Forum of 22 & 23 April 2020 Hydro Tasmania
4.11	Staged implementation	Alinta Energy CS Energy Delta Electricity
4.13	Implementation timeline	Forum of 20 & 23 April 2020 Delta Electricity Infigen Energy Origin Energy
4.14	Impact of COVID-19 on implementation	Alinta Energy CS Energy ERM Power Stanwell Hydro Tasmania Origin Energy
5.2	Publication of more detail on Affected GS settings	Forum of 22 April 2020 Delta Electricity

A detailed summary of issues raised by Consulted Persons in submissions and at the meetings and forums, together with AEMO's responses, is contained in Appendix B.

4. DISCUSSION OF MATERIAL ISSUES

4.1. Requirement to provide PFR

4.1.1. Issue summary and submissions

This is an issue that received numerous submissions indicating confusion over the requirement that PFR be provided when an Affected GS receives dispatch instruction to generate >0MW. The confusion is around which type of market the dispatch instruction applies to.

Infigen Energy submitted:

> Infigen suggests the requirement for Affected Generators to "*commence providing PFR every time they receive a dispatch instruction in the sport market of >0MW"* needs to be further clarified. At present, it is not clear if this instruction includes regulation markets, enablement for FCAS markets or just dispatch in the energy market.
>
> If AEMO's intention is for Generating Systems (GS) dispatched in the regulation market to provide PFR, AEMO should explicitly state the expected response for those units. For example, if PFR is to reduce output and AGC signal is to increase output, whether the response should be the sum of the signals or should the AGC signal be discarded. Similarly, for semi-scheduled generators when a cap is received lower than your maximum available output, but a frequency deviation would cause an increase in output (where possible), is there a priority of signals that should be followed? AEMO should provide explicit guidelines as to how conflicting signals should be treated.

Stanwell submitted:

> Stanwell's large units currently receive AGC targets which include both energy and regulating FCAS instructions where applicable. From the AEMO forums, Stanwell understands that under the PFRR a frequency response value is to be determined locally (e.g. via droop) and added to (or subtracted from) this AGC target in order to meet the combined energy, regulating FCAS and PFR obligations. While this is like some current arrangements for contingency FCAS, it is not clear whether such an approach will support system control in all circumstances.

4.1.2. AEMO's assessment

There are three spot markets that are impacted by this:

1. The energy market.
2. The Contingency FCAS market.
3. The Regulation FCAS market.

The other concern was over how *semi-scheduled generating systems* should respond during a *semi-dispatch interval*.

Energy market

For Affected GS participating in the energy market only, there should be no confusion.

Generation under AGC control

For Affected GS participating in the energy market plus either or both Regulation or Contingency FCAS markets, AEMO acknowledges that some further clarity is warranted. In effect, automatic generation control (AGC) targets should be treated as if issued at 50Hz and an Affected Generator should subsequently apply a droop function to its Affected GS around that AGC setpoint.

As discussed in the forum of 20 April 2020, AEMO considers that an Affected GS' response should be the sum of the AGC signals received and the requirement to provide PFR.

Energy and Regulation FCAS Markets

This is relevant to generation enabled for, and providing, Regulation FCAS under AGC control, but with a 0 MW energy market target. In this case, the actual MW output of a generating unit will be continually moving, either generating or absorbing MW under AGC control. Here, it is expected that PFR is provided in addition to this base movement in MW output controlled via AGC.

Energy and Contingency FCAS Markets

Where a generating system is dispatched for Contingency FCAS with a 0 MW energy target, the situation could be more complex. As an example, this could occur with hydro plant operating in tail-water depression mode, where the generating unit will be synchronised to the power system but will be operating with a 0 MW energy target. Should a significant frequency excursion occur, the generating unit will be able to switch from synchronous condenser mode to generation mode in a few seconds and produce a material Contingency FCAS response.

In this case, it is not reasonable to expect PFR to be provided as the generating unit is physically unable to do so when operating in this manner. This, of course, does not prevent the generating unit from being used to provide PFR if it is capable of doing so.

Semi-Dispatch

Where a semi-scheduled generating system is generating during a semi-dispatch interval, it is constrained by a 'semi-dispatch cap', thereby creating headroom, and it should use that headroom to provide PFR, where it can safely and stably do so.

This is consistent with the principle that the provision of PFR is a higher priority than strict compliance with a dispatch target. It is also entirely consistent with the long-standing treatment of scheduled generation subject to constraints in dispatch, where it is not required to block frequency response or lock governors when constrained to prevent an increase in output in response to a low frequency condition. Such a response would be expected and desirable.

4.1.3. AEMO's conclusion

AEMO has amended section 2 of the IPFRR to clarify what is expected of Affected GS operating in the energy market and FCAS markets, and when semi-scheduled generation is subject to a semi-dispatch cap.

The impact of the provision of PFR on time error management will be monitored.

4.2. Allowable deadband

4.2.1. Issue summary and submissions

Section 3.2 of the IPFRR gave rise to questions during the 22 April 2020 forum and in submissions that can be briefly summarised as:

1. Drafting should be clearer as to what is the widest permissible deadband.
2. How the allowable deadband is to be achieved.
3. The requirement should be based on Affected GS capability.

Delta Electricity submitted:

> It is understood that this clause presently contains a typographical error and that PFCB is considered by AEMO to be the minimum, not maximum, deadband possible to be assigned to a plant under the PFRR. It is anticipated that the determined Interim PFRR will be revised to indicate this.

> The deadband applicable at a site might necessarily be found, during the implementation and testing phase, to be required to be set at a wider level particularly where the Affected GS has several different mechanisms and controllers being coordinated to provide an overall system. It is recommended that the PFRR, in recognising existence of a complex system on a Unit, require only that at least one element in a complex system (e.g. the mechanical governor) be required to try to match the PFCB and other elements be set in consultation with AEMO to provide the overall most stable result.

ERM Power submitted:

> AEMO has indicated that "Each Affected GS must provide PFR outside the Affected GS' Deadband, which must be no wider than the *primary frequency control band* (PFCB)". We note however that the amended rules specify that PFCB is the minimum settings that AEMO may make the governor deadband setting for an Affected GS rather than the maximum allowable setting under the National Electricity Rules (NER). We also note that an Affected GS may apply for an exemption for actual governor deadband setting based on the inherent technical capability of the Affected GS. Therefore, we recommend that section 3.2 be amended to indicate;
>
> > Each Affected GS must provide PFR outside the Affected GS' deadband, which must be no wider than the deadband setting agreed between AEMO and the Market Participant for the Affected GS.

Infigen Energy submitted:

> The costs imposed on any single unit will depend on how active that unit will be in delivering PFR. Therefore, especially for smaller units, it is important that deadband settings are coordinated across all participants (to ensure, for example, that a small number of more capable units are not penalised for having that capability).
>
> Infigen therefore does not support the *maximum* (most relaxed) deadband in the Primary Frequency Response Parameters (PFRP) being set to the *minimum* (most restrictive) threshold permitted in the Rules. AEMO has not provided evidence that this is the "right" deadband for **all** scheduled and semi-scheduled generators in the NEM. If the most flexible assets are forced to have much tighter deadbands, they will incur much higher costs than less flexible assets – disincentivising further capabilities, as highlighted in Infigen's previous submissions to AEMC and AEMO.
>
> We therefore suggest that the required deadband setting be adjusted based on the outcome of self-assessments – with the maximum deadband setting being adjusted to reflect the "typical" capability of the fleet (e.g., the 90th percentile – if 90% of capacity can achieve a 0.015 deadband, then 0.015 likely to be appropriate).

CS Energy submitted:

> CS Energy also considers the requirements in section 3.2 of the draft Interim PFRR are ambiguous when read in the context of the balance of the document. This is because the Affected GS can seek a variation or exemption from AEMO for the actual governor deadband setting reflecting the Affected GS technical capabilities as specified by the original equipment manufacturer (OEM). Consequently, the Affected GS's Deadband may be wider than the PFCB.
>
> CS Energy proposes that the wording in section 3.2 be modified to read as follows:
>
> > "Each Affected GS must provide PFR outside the Affected GS' Deadband, which must not be narrower than the PFCB."

On the other hand, Hydro Tasmania, in its submission was entirely supporting of the narrowness of the deadband:

> Hydro Tasmania recognises the importance and value of primary frequency response (PFR) in the National Electricity Market (NEM) to enhance overall system frequency performance, and consider that this service will be particularly important as we move to an increasingly variable energy generation mix. We are generally supportive of the proposed methodology outlined in AEMO's Interim PFRR document, including the ±0.015Hz governor deadband proposal, the permanent droop requirement, and the PFR exemption principles.

4.2.2. AEMO's assessment

Clarity of drafting

AEMO agrees that the drafting of section 3.2 of the IFPRR could be improved.

AEMO has chosen to set the allowable deadband at the primary frequency control band (PFCB), which is defined in the PFR Rule as ±0.015 Hz and may be amended by the Reliability Panel.

AEMO's intention is that Affected GS ultimately be operated with frequency response deadbands no larger than the PFCB, currently specified as being within the range of 0 to ±0.015Hz. Clause 4.4.2A(b)(1)(i) of the PFR Rule states that AEMO cannot mandate a deadband that is narrower than the PFCB, but this does mean that Affected GS cannot operate with a narrower deadband, even a zero deadband, if they wish to do so.

Furthermore, if Affected GS already operate with a narrower deadband, they are not required to widen it to meet the PFCB.

How the allowable deadband is to be achieved

Some Consulted Persons interpreted the term 'deadband', used to describe one of the performance requirements in the PFR Rule and IPFRR, as a requirement that all available, or possible, deadbands within Affected GS' control systems must be at or below this value. A number of Generators provided detailed submissions on the complexity of generation control systems to show this would not be feasible.

AEMO is not attempting to prescribe exactly how Affected Generators should implement setting changes to achieve the PFCB, or any other performance requirements specified in the IPFRR. AEMO agrees that the complexity of the design and arrangement of generation control systems might mean that achieving the parameter specified in section 3.2 of the IPFRR can be achieved in different ways for different Affected GS.

Due to differences in the design and technology between different types of generating systems, different control system settings, modes of operation and adjustments will be required to meet the requirements of the IPFRR.

For some Affected GS, the changes will be simple, and might only affect a single setting. For others, a range of different control systems could require adjustment, setting changes, or changes to their mode of operation to achieve the desired outcomes.

The Self-Assessment was conceived because of the wide range of different control system designs and generation technologies across generation in the NEM. It is intended that Affected Generators advise AEMO how they intend to achieve the requirements specified in the IPFRR.

Ultimately, AEMO is only concerned about an Affected GS' performance at the connection point. AEMO wishes to see each Affected GS respond whenever the frequency is outside a small deadband, which is set at the PCFB. For Affected GS that is capable of performing in that way, how each Affected Generator achieves that outcome is within each Affected Generator's discretion.

The requirement should be based on capability

The PFR Rule is predicated on implementation based on Affected GS' inherent capability. Any other measure detracts from that outcome and, potentially, leads to inequitable treatment of different types of generating systems.

ERM suggested that the interim and final deadband settings should be negotiable. For reasons that have been explored extensively during consultation on the PFR Rule, the final deadband settings must be consistent across the NEM's scheduled and semi-scheduled generation, to the degree this can reasonably be achieved, at ±0.015Hz. By opening the deadband settings to negotiation with each Affected Generator, the PFR Rule is unlikely to be implemented in a way that achieves its purpose within a reasonable time, or even at all.

Infigen suggested that the deadband be set at scheduled and semi-scheduled generation's 'typical' capability. Again, this is likely to frustrate the purpose of the PFR Rule in seeking to enliven existing capabilities within the NEM.

Variations may be approved on an ad hoc basis, but only if an Affected Generator can demonstrate a lack of capability as contemplated by the principles in clause 4.4.2B of the PFR Rule.

An interim setting of ±0.05Hz was suggested during the forums as a known setting with which Affected GS in New South Wales have operated in the past. AEMO has agreed to adopt this as an interim step towards a managed transition in getting to ±0.015Hz.

4.2.3. AEMO's conclusion

AEMO has amended section 3.2 to make it clear that Affected GS must respond to frequency deviations from 50Hz by ±0.015Hz at the connection point.

4.3. Whether all Affected GS should be operating with the same deadband

4.3.1. Issue summary and submissions

Some Consulted Persons queried the prudence of requiring all Affected GS to operate with a deadband of ±0.015Hz. This issue was highlighted during the forum of 29 April 2020.

4.3.2. AEMO's assessment

During the workshop on 27 February 2020, AEMO acknowledged that the operation of some Affected GS at a ±0.015 Hz deadband may be inadvisable. Provided these cases are allowed for within the PFRR framework, however, there is no theoretical problem with having a standard specification across all Affected GS.

AEMO requires all Affected GS to be frequency-responsive where the frequency varies outside a small deadband (specified as 49.985Hz to 50.015Hz) at the Affected GS' connection point, unless there is a clear reason why this is not appropriate, and an exemption or variation has been granted.

One of the benefits of applying consistent deadband settings to the greatest degree practicable is to avoid the reality, or appearance, of free riders, particularly in a near universal, and non-compensated service as is required by the PFR Rule. Any Affected Generator permitted to operate on a wider deadband than others in the absence of a variation based on sound technical reasons, is essentially receiving the benefit of the more stable control of frequency provided by the others, without contributing to that outcome. The materiality of this issue depends on the level of variation in the deadbands applied, but the principle is important.

A range of comparable power systems have a similar standard, namely, one narrow deadband setting with adjustments only for outliers, where required.

4.3.3. AEMO's conclusion

AEMO has determined not to change to the IPFRR in response to this issue.

4.4. Operating with a wider deadband

4.4.1. Issue summary and submissions

Several Consulted Persons asked AEMO during the forums whether AEMO would accept wider deadbands than the PFCB. There were also submissions made on this issue. The issues raised can be summarised as:

1. Whether a wider deadband is permissible.
2. Impact on Affected GS that cannot achieve PFCB by design.
3. Level playing field.
4. Payment for superior performance.

The Clean Energy Council (CEC) put it this way:

> Section 3.2 (Deadband) of the document notes that each affected generator must provide PFR outside the Affected GS' Deadband, which must be no wider than the PFCB. At the AEMO workshop held on the 27th of February 2020, AEMO stated that not every generator will have the same deadband applied and there is scope for a generator to agree a wider deadband with AEMO. The ability to agree a wider deadband with AEMO is not included in the document. The CEC wish to clarify whether there is scope for a wider deadband.

Delta Electricity submitted[2]:

> Delta Electricity considers that the National Electricity Objective requires that if a particular plant in a local region cannot achieve the tightness of overall deadband of +-15mHz and a larger deadband is agreed by AEMO to apply at that plant then, in the interests of fair competition in the application of a mandatory Rule, other nearby plant of similar technology should be advised and permitted to relax any relevant part of a complex controller to be no narrower than the deadband permitted by AEMO for the nearby competitor. An alternative to this approach would be for AEMO to develop a compensation process for superior performance.

AGL Energy submitted:

> Clause 4.4.2A of the final rule states that the PFRR must include a requirement that relevant generators will provide PFR, and must do so within a maximum allowable deadband, which cannot be narrower than the National Electricity Rules (**NER**) prescribed control band of 49.985Hz to 50.015Hz (**PCB**).
>
> The AEMC's final rule has given AEMO flexibility to allow generators provide PFR at a wider deadband than the PCB, however the drafting of the PFRR V1.2 does not explicitly support or give effect to this flexibility. We understand from the meetings AEMO hosted in April 2020, that the intention is to preclude narrower deadbands than the PCB, but not necessarily wider deadbands.
>
> As detailed in our submission to the AEMC's draft determination, much thermal plant in the National Electricity Market (**NEM**) was constructed and designed with PFR at +/- 0.025Hz, while other plant control systems can only be set to two decimal places and therefore cannot measure PFR to three decimal places. In short, a significant amount of plant will be simply unable to meet a +/- 0.015Hz deadband without significant investment. In AGL's view, for plant that cannot easily meet the PCB, it is better to have these generators contributing at other levels (for example, +/- 0.025Hz or +/- 0.02Hz) than not at all, and the PFRR should reflect that this could be an acceptable outcome for some generators under the variation provisions.

Tilt Renewables submitted:

> In previous submissions to the AEMC Tilt Renewables has highlighted the differing costs associated with providing PFR across technologies. As semi-scheduled generation will typically be required to spill near-zero marginal input cost energy to provide primary frequency response, Tilt Renewables considers that the costs for providing this service will likely be higher for semi-scheduled generators compared to

[2] Delta Electricity made the same submission under different headings: Section 3.2 - PFR Parameters – Maximum Allowable Deadband and Section 10(c) - Publication of Primary Frequency Response Outcomes – (c) variations.

scheduled generators. This is further compounded by the fact that MW losses relating to providing PFR (Primary Frequency Response) for conventional generators due to curtailing output to respond to over frequency will be largely cancelled out by responding to under frequency – noting that conventional generators will use less fuel/water to respond to over frequency. To reflect the higher costs associated with providing PFR on semi-scheduled generators Tilt Renewables suggests AEMO explore the option of having higher and wider droop and deadband settings on semi-scheduled generation to ensure that most of the response is provided by those technologies able to provide this service at the lowest cost.

4.4.2. AEMO's assessment

Whether a wider deadband will be permissible

AEMO indicated during the forums that permitting Affected Generators to seek a progressive narrowing of their deadbands rather than achieving the PFCB in one change necessarily means that Affected GS will be operating with deadbands that are wider than the PFCB, but this will only be temporary.

While the PFR Rule gives AEMO the option to set a deadband that is wider than the PFCB, this does not preclude AEMO from adopting the PFCB as the specification of the widest permitted deadband.

During the course of reviewing the results of the Self-Assessments, AEMO might be made aware of the need for some Affected GS to operate with wider deadbands because they cannot operate at the PFCB by design, or because of inherent plant instability issues. These situations could form the basis for an application for variation, which AEMO would need to assess on its merits based on the information provided with the application.

Variations to operate at wider deadbands outside of these circumstances would be exceptional.

The PFR Rule was made to enliven existing capability across all scheduled and semi-scheduled generation in the NEM. If any Affected GS is inherently capable of operating to meet the PFR Rule, it will be required to do so. The only plant that will be permitted to operate without frequency response, or with a wider deadband, will be Affected GS that meets either the exemption or variation criteria.

Impact on Affected GS that cannot achieve PFCB by design

As noted above, Affected Generators with Affected GS that cannot achieve the PFCB by design should submit an application for exemption if the plant is inherently incapable of being frequency-responsive, or an application for variation, if the deadband that can be achieved based on inherent capability is wider than the PFCB.

The latter case would apply to AGL's example where Affected GS was designed with deadbands at ±0.025Hz or cannot be measured to three decimal places.

Level playing field

Delta Electricity's proposal that Affected Generators be afforded the opportunity to widen their deadbands to the widest common denominator to maintain a level playing field would not achieve the purpose of the PFR Rule.

The PFR Rule was made because it met the national electricity objective (NEO). It makes the provision of PFR a mandatory and universal obligation, and discretion is left with AEMO to implement the PFR Rule to improve power system security. The idea that competition requires all Affected GS operate according to the widest permitted deadband, even if that deadband were approved on an exceptional basis, undermines the PFR Rule.

Furthermore, while different types of generation technology have different pressure points when it comes to the cost of operation, the PFR Rule only considers costs in the context of applications for exemption or variation if the costs of meeting the PFR Rule would be 'unreasonably onerous' given a set of criteria. The

PFR Rule does not support AEMO's setting of different deadbands for different types generation technology based on their different cost profiles.

Payment for superior performance

Delta Electricity's suggestion of payment for superior performance is a matter that is not addressed by the PFR Rule and is not within AEMO's remit. AEMO understands the AEMC will consider these matters in its consultation on the Removal of disincentives to primary frequency response rule change proposal.

4.4.3. AEMO's conclusion

Wider deadbands will only be considered on an exceptional basis, namely, for those Affected GS that are inherently incapable of meeting the ±0.015Hz requirement while those who wish to operate with a narrower deadband are not precluded from doing so.

Any Affected Generator who considers their Affected GS cannot operate in accordance with that requirement will need to apply to AEMO for an exemption or variation and provide detailed reasons and substantiation for AEMO's consideration.

4.5. The use of P_{MAX} as a reference point

4.5.1. Issue summary and submissions

Several Consulted Persons raised the choice of P_{MAX} as a reference point, citing a concern that renewable generation will shoulder a disproportionate share of the provision of PFR. AEMO had indicated during the forums that it was open to exploring alternative parameters if they were more appropriate.

The concerns raised can be summarised as:

1. AEMO has retracted representations made during the forums.
2. Droop should be negotiable.
3. The burden on renewable generation will be higher than on conventional generation.
4. Droop should be based on Affected GS' availability.

The CEC submitted:

> Section 3.3 (Droop) displays equation 1 that demonstrates how droop will be calculated. During the AEMO workshop referenced above, AEMO stated that the change in active power would be based on the available power at the time. Therefore, AEMO should clarify the interpretation of **P_max** in the droop equation to avoid confusion. It is important that this is clarified in the PFRR document as generators should respond to frequency changes outside the PFCB based on their current level of generation.

Edify Energy submitted:

> We refer to section 3.3 (Droop) which defines PMAX in Equation 1 (Droop definition) as "Maximum Operating Level in MW" of a Generating System being the maximum allowed export capacity of the generator. We would propose that PMAX should be replaced with the actual power being generated at the time of the frequency deviation or that this could be negotiated on a project by project basis.
>
> Renewable energy generators often only operate at a level below maximum output based on the available resource. Making the change to actual power prior to the frequency deviation would ensure an overall proportional response to frequency deviations regardless of weather conditions and time of day.

Tilt Renewables submitted:

> Equation 1 in Section 3.3 of the PFRR details the droop calculation which describes how the generator is expected to alter its active power output in response to frequency deviations. AEMO has suggested in previous workshops that the droop would be calculated based on P_available as opposed to P_max which is now used in the PFRR. The consequence of the change for VRE (Variable Renewable Energy) is that

> its share of PFR provided will be much higher than its share of energy supply compared to conventional generators. Wind in particular is nearly always online, so under the proposed droop definition it would be providing PFR proportional to its installed capacity the majority of the time, despite only being capable of producing a proportion of that installed capacity as active power due to prevailing wind speeds.
>
> By using P_max in the droop calculation instead of the initially considered P_available, AEMO in its drafting of the PFRR has failed to consider differing technologies and has placed a more cumbersome burden with respect to PFR on VRE. During the industry workshops AEMO stated its desired to achieve a shared frequency response across the generation fleet such that each generator is 'pulling their weight'. Tilt Renewables estimates that the increase in energy spilt/lost for wind by using P_max instead of P_available in the droop calculation will be inversely proportional to the capacity factor of the generating system (for a typical wind farm with ~30% capacity factor this would equate to 1/.3 = 3.33 times the losses). This result would not be an appropriate outcome of the PFRR regime.
>
> Given the above Tilt Renewables requests that P_max in the droop calculation be replaced with P_available.

Origin Energy submitted:

> **Definition of droop should reflect generator availability**
>
> The formula for droop in the draft PFRR is based on the maximum operating level of the generating system (Pmax). Defining droop in this way could create issues as a generator may be generating less than its maximum capacity when called upon to respond to frequency deviations. We suggest that the Pmax in the formula should instead be defined as the availability of the generator at the time of the frequency movement.
>
> Additionally, where part of a generating system has an exemption (e.g. the steam stage of a CCGT), this should be excluded from the Pmax of the generating system used to calculate the level of droop.

AGL Energy submitted:

> Regarding the droop and response time parameters, AGL is concerned that the measurement of this remains tied to P_{MAX}. The PFRR state that "[T]he response time is measured from when the *frequency* crosses the limit of the Affected GS' Deadband until *active power* reaches a 5 % change based on P_{MAX}." For generators that have multiple generating units under one dispatchable unit identifier (**DUID**), such measurement would not be appropriate, nor would it be appropriate for hydro generators whose maximum output level depends on storage dam levels.
>
> This issue was discussed at length during the April meetings where AEMO acknowledged that generators enabled for PFRR are expected to respond in line with plant capability, including any limitations, at the time of the frequency disturbance. In AGL's experience, incremental droop responses are unlikely to meet the 5% parameter at all times due issues such as non-linear unit response, process conditions, or the load range/magnitude of the frequency deviation, which all affect the P/ P_{MAX} portion of the droop calculation. We consider the PFRR should provide further detail on how such limitations will be treated when assessing generators' compliance with the droop and response time requirements.

4.5.2. AEMO's assessment

General Comment

This issue is about the consistent treatment of different generation technologies. Control systems have long been set by reference to P_{MAX}, namely, to the rated size of a generating system. This is a key purpose of droop - whether it is for voltage or frequency control - to allocate response across generation in proportion to plant size and ensure generation can be operated in parallel in a stable manner when collectively controlling some common variable, such as frequency, or local voltage.

AEMO has retracted representations made during the forums

During the forums, AEMO indicated on a number of occasions that it was open to the use of other parameters than P_{MAX}, if they were more appropriate. AEMO invited suggestions from Consulted Persons on alternative measures, noting that it must be a fixed value.

For clarity, AEMO's comments made during each forum are detailed in the table below:

Date	Notes from forum	Reference
20 April 2020	In response to an ad hoc question about the droop being relative to P_{MAX}, AEMO advised that the requirement be applied per operating generating unit and asked for Consulted Persons to submit other parameters, if they considered them to be more appropriate.	Page 3
22 April 2020	Section 3.4 – Has there been any discussion on the use of P_{MAX} as a reference point? AEMO is open to the use of other parameters if they are more appropriate and looks forward to suggestions from Consulted Persons on this issue. If a Generator wishes to use a different Power base for specifying droop, this should be noted in the self-assessment.	Page 3
23 April 2020	Section 3.4 – Has there been any discussion on the use of P_{MAX} as a reference point? In the case of hydro plant, dam level might be a more appropriate parameter. AEMO is open to the use of other parameters if they are more appropriate and looks forward to suggestions from Consulted Persons on this issue. Control systems are set based on P_{MAX} and not adjusted by reference to dam levels on a day-to-day basis, and neither is the droop setting. AEMO does not expects that unit control tuning would be continually adjusted in response to system conditions. If there is any particular issue with this, it can be addressed by way of variation.	Page 2
29 April 2020	Section 3.3 – The use of P_{MAX} as a reference point for renewables will be problematic. Doesn't this mean that renewables are taking a bigger hit than thermal generation? The proposed approach is consistent with existing approaches. The MW change in output for a given change in frequency (i.e. the droop) should be based on a fixed rated capacity, not capacity available at any point in time. If the rated capacity of the plant can change, for example, due to the online status of individual generating units in a multi-unit hydro plant, or availability of inverter or turbine strings in a VRE plant, the MW response to a given frequency change will also change. It is not expected that droop is continually adjusted based on current conditions. AEMO is open to the use of other parameters than P_{MAX}, if they are more appropriate and looks forward to suggestions from Consulted Persons on this issue but wants this to be a fixed value. Where it is a minimum or maximum operating level issue, this is addressed by way of standing variation. Renewables should not be taking a disproportionate share of the load in addressing small frequency variations because it is relative to the size of plant as a proportion of the total plant generating at any time. This is the key purpose of droop control of power in response to frequency changes – to allocate response across all generation in proportion to plant size. If there is any particular issue with this, it can be addressed by way of variation.	Page 2-3

Droop should be negotiable

It is an underlying principle of the PFR Rule that all capable scheduled and semi-scheduled generation should contribute PFR in proportion to their capacity. Edify Energy's suggestion to permit droop to be negotiated, would be inconsistent with this principle.

The burden on renewable generation

For generation technologies, such as wind and solar, the instantaneous output of a generating system is typically tied to instantaneous availability of the primary energy resource, assuming no curtailment, however, there is no obvious technical reason why its response to frequency needs to change on with the availability of the primary energy resource, as the installed capacity of a generating system does not change.

Use of a consistent value, such as P_{MAX}, for determining droop response ensures an Affected GS' response to a change in frequency remains consistent and is not dependent on its output level at the time of the change in frequency.

The MW change in output for a given change in frequency (namely, the droop characteristic) should be based on a maximum capacity, not the available primary energy resource at a point in time. If its response were to vary on that basis, an Affected GS' contribution to overall system frequency control would reduce significantly.

If a case could be made that changing an Affected GS' droop response to align with the IPFRR was not possible, or the costs involved in doing so could be regarded as unreasonably onerous, an application for a variation of this requirement could be made.

Allowing a generating system to scale its response to frequency based on instantaneous primary energy resource availability would greatly reduce its contribution to the overall system frequency response, broadly in line with its annual operating capacity factor (assuming it could run unconstrained at all times).

This is not consistent with the PFR Rule, which is to allocate a minimum frequency response obligation to all capable scheduled and semi-scheduled generating systems in the NEM, in proportion to their installed capacity.

Droop should be based on Affected GS' availability

Origin Energy's proposition aligns with the requirement that droop be based on P_{MAX}.

Where the rated size of an Affected GS effectively changes, say, due to the temporary outage of PV inverters or wind turbines, or due to only a some generating units being in service, it is expected that its frequency response at the connection point will change. The P_{MAX}, or size, of the generating system, has temporarily changed.

4.5.3. AEMO's conclusion

AEMO has determined not to change the use of P_{MAX} as a reference point in section 3.4 of the IPFRR.

4.6. Limitations on delivery of PFR

4.6.1. Issue summary and submissions

Some Consulted Persons wanted to ensure that all plant and operational limitations were captured so that there were no inadvertent non-compliances. A number of submissions sought to identify new issues.

Delta Electricity submitted:

> As evidence of the potential for variability in response times during real system events, attachment 3 includes a table of results from recent deadband testing (February and March 2020) of Vales Point Unit 5. The amount of stored energy on a Unit, fuel conditions, ambient conditions, interactions between interconnected control systems of a single Unit, interactions between Units across the NEM and the electrical dynamic response of the NEM at different times of the day and the year all impact on Units being able to consistently deliver on parameters such as response time if too precisely defined. The capability may exist but due to system variability only be demonstrated in 50% of responses, for example. A Units response can also be affected by the AGC dispatch delivery and the timing of dispatch intervals relative to when a frequency response is required. Units will be capable of delivering the specified PFRR response time but, due to many variables in the Unit, the Network and AEMOs dispatch systems should not be expected to consistently deliver it.

…

The Draft PFRR assumes a simple system. In reality, systems such as that installed at Vales Point involve several controllers that work differently.

To simplify the self-assessment process, Delta Electricity recommends the PFRR include standard variations for Units like that at Vales Point permitting PFR only apply above self-commitment levels and when able to be automatically dispatched by AEMO. At other times, Units are operated off coordinated modes, manually or in automatic response to detected conditions, to prevent loss of Unit. Manual controls attempt to stabilise a Unit and if achieved operators then return the Unit to full automatic control.

In Turbine Follow control mode, as is commonly used during Unit start up but also automatically engaged after larger plant-related disturbances to maintain safe conditions and Unit security, the DCS provides no form of frequency control. In Turbine follow mode, the DCS uses the governor to control steam pressure only.

No redesign is considered practical on the mechanical governing systems nor the governing systems that control a Steam Unit when being synchronised or regulating initial Unit loading prior to valve transfer to the mechanical governor and throttling valves.

Simple adjustments to existing FCAS controllers installed in the Unit DCS are preferred and will provide more prompt addressing of system security concerns than will extensive redesigns.

…

There will be operational reasons, including low load operations below registered minimum loads, and test conditions of a temporary nature where subparts of or the overall Affected GS PFR controller may need to be taken out of service. Some conditions will automatically remove the system from operation. Where possible, AEMO agreement to the temporary removal from service of PFR will be sought and AEMO informed prior to withdrawal and following reinstatement. It is understood that AEMO is already considering including such circumstances as Standard Variations in the PFRR. [3]

…

Outside of NOFB limited PFR responses, rapid lower responses larger than Performance standard (S5.2.5.7 Partial Load Rejection) values should be considered standard limitations on PFRR. Many plants will have a protection system that will interrupt their Unit if the load drop exceeds the GPS registered value.

…

The imperative of implementation of mandatory PFRR should be on urgently addressing AEMOs system security concerns regarding existing frequency quality. Where an existing controller can simply be adjusted to deliver PFRR droop and an overall Unit governing deadband approaching the PFCB, great flexibility in accepting other PFRR parameters is recommended over specific detailed and strict compliance expectation.

ERM Power submitted:

With regards to section 4.2 we suggest the following amendment;

> maintain operation between the Affected GS' current prevailing Maximum Operating Level and Minimum Operating Level

This will ensure that the current prevailing operating conditions, including ambient temperature, are considered when assessing this outcome.

…

We recommend that two additional dot points be added to section 9.1 to indicate;

- prevailing ambient temperature conditions

[3] Delta Electricity made the same submission under different headings: Section 4.1 - No Withdrawal of Response, Section 4.3 - Continuity of Response and Section 9.2 - Changes to PFR settings.

which is a critical consideration for gas turbines, and

- when operating in accordance with the provisions of NER Clause 3.8.19 – Dispatch inflexibilities

The need for an Affected GS to operate in a mode where it is unable to comply with a dispatch instruction predominantly occurs in real time and the ability for a generator to request exemption from AEMO in accordance with subsection 9.2 in this circumstance, is in our view impractical.

Further, the Rules are clear and substantive as to when an Affected GS may submit a dispatch inflexibility dispatch bid or offer and that a generator may only submit a dispatch inflexible dispatch bid or offer where the Affected GS is unable to follow dispatch instructions and is subject to the Market Participant for the Affected GS supplying to the Australian Energy Regulator (AER) upon written request;

> "such additional information to substantiate and verify the reason for such inflexibility as the AER may require from time to time."

We consider that the requirements of Clause 3.8.19 of the NER are sufficiently clear and substantive so as to provide to AEMO clear evidence for the reasoning where PFR is not provided during a period where an Affected GS has submitted a dispatch bid or offer and is operating under the provisions of Clause 3.8.19. This would remove a potential compliance burden on both market participants and the AER.

Stanwell submitted:

Whilst we understand that the intent of this clause is that PFR is to ordinarily be enabled, it needs to be acknowledged that there are a variety of conditions, (for thermal boiler plant in particular) under which frequency control mode may need to be temporarily disabled. Such conditions can include, but are not limited to the following (some of which are typically handled by bidding the plant inflexible):

- boiler protection actions;
- boiler run backs caused by loss of various boiler auxiliaries;
- plant testing;
- mill trips; and
- low load operation.

Under such circumstances, the control mode will be automatically or manually switched out of frequency response. Whilst this is an infrequent occurrence, it would add little value to communicate to AEMO every time. This could result in unnecessary administrative burden on generating and AEMO operations staff.

Stanwell suggests this should be included as a standing variation in the PFRR for particular plant types (perhaps under a new clause 7.6). Doing so would alleviate the requirement for replication of such criteria under clause 7.1.5 by multiple individual applicants.

Origin Energy submitted:

Exemption requests should consider planned upgrades or maintenance

In considering exemption requests, AEMO should take into account pre-existing plans for plant upgrades and maintenance. Some plants may not have current PFR capability in line with the PFRR but do have subsequent plans for upgrades or maintenance that would improve their ability to provide frequency response. These generators should be allowed to receive an exemption up until the time these previously planned upgrades have been made. Bringing forward these works could lead to undue costs and require generators to deviate from their predetermined optimal development/maintenance plans.

There should be a process for generators to inform AEMO of temporarily disabled PFR

The PFRR should lay out the process for generators to inform AEMO of a temporary disabling of frequency response capability. Generators will occasionally need to temporarily remove the capability for testing or maintenance, while still supplying energy.

CS Energy submitted:

CS Energy suggests references in section 4.2 of the draft Interim PFRR document to maintenance of operation between the Affected GS' Maximum Operating Level and Minimum Operating Level requires recognition of conditions such as ambient temperature de-ratings, stability issues and other intermittent operational issues.

…

CS Energy considers it essential for compliance with any regulatory requirements that the requirements can be clearly interpreted. CS Energy would encourage AEMO to address in the final Interim PFRR the inconsistencies between section 4.1 (No withdrawal of response), section 7.1.5 (Physical characteristics) and section 9.1 (Ability to operate in frequency mode and sustain PFR).

The need for an Affected GS to operate in a mode where it is unable to comply with a dispatch instruction predominantly occurs in real time or during planned work that may involve testing or process safety. The requirement for a generator to request a variation or exemption from AEMO in accordance with subsection 9.2 is already covered in existing market processes.

Further, the Rules are clear and substantive as to when an Affected GS may submit a dispatch inflexibility dispatch bid or offer and that a generator may only submit a dispatch inflexible dispatch bid or offer where the Affected GS is unable to follow dispatch instructions.

This position is consistent with CS Energy's comments in section 6 of this submission.

…

Section 2 of the draft Interim PFRR provides:

> "Unless exempted by AEMO, or the PFRP are varied, under section 7, Affected Generators must commence providing PFR every time they receive a dispatch instruction in the spot market of >0MW in respect of an Affected GS … ."

CS Energy recommends AEMO provide further detail on what constitutes '>0MW' and how it applies to different generation technologies. CS Energy considers the detail should specify the following:

(a) that it excludes a PFRR when in shutdown and start-up mode, when operating at the minimum safe operating level (MSOL) or at the Self Dispatch Level; and

(b) expected PFRR when enabled for and delivering FCAS Regulation and Contingency Services or during the provision of wide band frequency response.

4.6.2. AEMO's assessment

General

AEMO understands that plant limitations could be identified by plant type or be specific to an Affected GS. In the initial draft of the IPFRR, AEMO included those it could identify as generic in sections 4.2 and 9.1 of the IPFRR so that their occurrence would not be seen as non-compliances.

As a result of discussions during the forums, AEMO considers that these limitations are best dealt with by way of standing variations, rather than as mere acknowledgements of plant limitations. To remove the need for frequent communication between AEMO and Affected Generators and the need for Affected Generators to apply for short-term variations, AEMO asked Consulted Persons during each of the forums to advise AEMO of any other issues that should be included as standing variations.

Limitations covered already

From the examples raised by Consulted Persons, AEMO notes:

- Operating within the Minimum Operating Level and Maximum Operating Level was already accounted for in section 4.2 of the IPFRR and is now a standing variation in section 7.6.

ERM Power's suggestion to refer to the 'current prevailing' Minimum Operating Level and Maximum Operating Level is not required, by virtue of the definition of those terms[4].

- Ambient temperature is accounted for in the existing section 9.1 where it refers to the safety and stability of an Affected GS due to operating temperature limits and is now a standing variation in section 7.6.

Plant out of service

Affected GS need to be available for dispatch to receive a dispatch instruction to generate >0MW before the obligation to provide PFR would arise.

Affected Generators who take their Affected GS out of service to undertake maintenance or tests are unlikely to be issued with a dispatch instruction because AEMO understands the general practice is that they are bid 'unavailable' in AEMO's market systems and so do not receive any dispatch instructions for the duration of the outage.

Testing while an Affected GS remains online is now included as a standing variation in section 7.6.

4.6.3. AEMO's conclusion

AEMO has replaced sections 4.2 and 9.1 of the IPFRR with a new section 7.6, which lists a range of possible plant limitations as standing variations to make it clear that no compliance issues should arise if any of these conditions are met, removing the need for making application for a variation for the duration of one or more of those conditions.

The new items included in the list in section 7.6 that were not previously noted in the earlier draft in sections 4.2 or 9.1 are:

- To effect the start-up or shutdown of the Affected GS, including following plant disturbances.
- To manage self-commitment, synchronisation, decommitment and de-synchronisation of the Affected GS.
- While the Affected GS is inflexible.
- Where the Affected GS is comprised of one or more hydro generating units, while they are being operated in tail-water depression mode.
- To the limit of an Affected GS' obligations and capabilities, as expressed in the performance standards under clause S5.2.5.7 and S5.2.5.8 of the NER.
- To conduct tests on the Affected GS.
- Limitations due to prevailing ambient temperature.

4.7. Exemption and variation criteria

4.7.1. Issue summary and submissions

There has been significant discussion over the nature of the exemptions and variations and the criteria AEMO will apply when reviewing applications for exemption or variation. The issues include:

1. The difference between an exemption and a variation.
2. Reasonableness test.
3. Magnitude of costs to be considered excessive.

[4] See the definition of these terms in clause S5.2.5.11 of the NER.

4. Ability to reapply for exemption or variation.
5. Capability limited to OEM specification.

ERM Power submitted:

> AEMO in 7.1.1 set out the basis for full or partial exemption based on the technical capability of the Affected GS. To improve clarity in this area with regards to interaction with the original equipment manufacturers technical envelope, we recommend that this subsection be amended to;
>
> > If an Affected Generator's application for exemption or variation is on the basis that an Affected GS is inherently incapable of operating in frequency response mode, or meeting some particular PFRP, the Affected Generator must demonstrate this incapability no matter what changes are made to the Affected GS by providing AEMO with copies of relevant original equipment manufacturer (OEM) specifications, or test results, or advice."
> >
> > For the avoidance of doubt, AEMO acknowledge that an Affected GS cannot be required to operate outside the technical envelope approved by the original equipment manufacturer.
>
> We believe it is critical that the final interim PFRR must not set out a requirement that would lead to the Affected GS being operated in a way that is detrimental to generating unit operations as set out by the OEM.

CS Energy submitted:

> In section 7.1.1, CS Energy would like AEMO to acknowledge that an Affected GS cannot be required to or will be operated outside the technical capability approved by the OEM.
>
> In section 7.1.5, AEMO details a list of eligible examples that an Affected GS(s) can utilise in an application for exemption from or variation to, any of the primary frequency response parameters. CS Energy notes that the list reflects existing market processes and operational outcomes that that may occur on occasions that are managed and accommodated in the Rules and procedures. CS Energy does not agree with the list and would expect an exemption to reflect the inability to provide PFRR and a variation as a permanent restriction or inability to meet aspects of the PFRR.

Infigen Energy submitted:

> The clause requiring participants to "demonstrate this incapability no matter what changes are made to the Affected GS by providing AEMO with copies of relevant original equipment manufacturer (**OEM**) specifications or test results" (emphasis added) seems onerous and arguably impossible to comply with – one cannot prove a negative. While this rule may be appropriate for thermal power stations, wind farms and inverter-based technologies have significantly more options available (e.g., replacement of control systems, etc., with exponential cost increases). We suggest a reasonableness test be applied – with consideration of the relevant OEM specifications, test results, and incremental changes to the plant.
>
> It is also unclear what magnitude of costs will be deemed too excessive by AEMO in order to apply for a variation or exemption.
>
> Providing evidence of expected ongoing costs will be difficult when there is little known about the outcome of this rule change, especially on generators that have never provided frequency response. We recommend that exemption principle 7.1.4 of the interim guidelines be made ongoing, such that participants relax deadband settings or be exempted if actual costs prove to be too high. This will maximise initial participation in the market and reduce costs to businesses (by not forcing participants to request exclusion upfront to manage uncertain risks).

AGL Energy submitted:

> AEMO has outlined a number of principles it will have regard to when considering applications for exemption or variation to the PFR parameters. In our view, these principles appear more targeted towards exemption.
>
> We propose the inclusion of a principle focused on variation, articulating that existing generators should provide PFR with fixed droop and deadbands within their design limits, while remaining as close as practical to AEMO's nominated parameters. In our view, it is appropriate to acknowledge that current

> generator control systems were established in good faith to comply with the regulatory requirements of the day and the shift to mandatory PFR should respect existing investments.
>
> For example, AGL's submission to the AEMC's draft determination highlighted that the Australian Standard for Droop has historically been set at 4%, and many generators would be configured to comply with this historical setting. Accordingly, it's likely these generators would seek a variation to AEMO's 5% Droop parameter.
>
> Section 7.3 of the PFRR implies that generators can seek to vary any of the PFR parameters by referencing the form in Appendix E. AGL considers it would be helpful to expressly state that variation of individual PFR parameters is possible where necessary.

4.7.2. AEMO's assessment

Difference between an exemption and a variation

Many participants in AEMO's forums have different views on the difference between an exemption and a variation. Some asked AEMO to provide for 'partial exemptions'.

For clarity, AEMO considers that:

- An exemption can be sought only when an Affected GS is not frequency responsive and cannot be made so, having regard to one or more of the factors in clause 4.4.2B(a) of the PFR Rule.
- A variation should be sought when an Affected GS is, or can be made to be, frequency-responsive, but not to the degree required to meet one or more of the Primary Frequency Response Parameters (PFRP) in section 3 of the IPFRR. Again, the factors in clause 4.4.2B(a) of the NER apply.

Reasonableness test

The PFR Rule is predicated on the reasonable use of existing capability in the NEM's scheduled and semi-scheduled generation to provide PFR. All applications for exemption or variation will be considered through that lens.

AEMO acknowledges that section 7.1.1 of the initial draft IPFRR was not clear. AEMO's intention was to state that where, by design, an Affected GS cannot be made frequency-responsive, evidence of this will be required from the OEM. The provision of comparable advice from a suitably qualified consulting engineer is now included as an alternative to OEM information.

Where there is a possibility that an Affected GS could be made frequency-responsive, the only basis on which an application for exemption would be considered is whether, as stated in clause 4.4.2B(a)(4) of the PFR Rule:

> the *Scheduled Generator* or *Semi-Scheduled Generator* has been able to establish to *AEMO's* reasonable satisfaction that the implementation of the *primary frequency response parameters* applicable to that *Scheduled Generator's* or *Semi Scheduled Generator's generating system* will be unreasonably onerous having regard to (among other things):
>
> (i) the likely costs of modifying the *generating system* to be able to operate in *frequency response mode*; and
>
> (ii) the likely operation and maintenance costs of operating the *generating system* in *frequency response mode*,
>
> relative to the revenue earned from the provision of *energy* and *market ancillary services* by the *generating system* in relation to its operation in the *NEM* during the 12 months prior to the date of the application for exemption or variation, as applicable.

Appropriate changes will be made to section 7.1.1 to reflect this.

Magnitude of costs considered excessive

In the absence of any financial data, AEMO is unable to provide any guidance on the level of expenditure (capex and opex) that would be considered to be excessive. Furthermore, it is an assessment that has to be carried out by reference to the revenue generated by an Affected GS in the 12 months prior to the date of the application.

Where necessary, AEMO intends to seek independent advice on issues such as the cost of various works and typical return on investment for different types of generating systems during implementation.

Ability to reapply for exemption or variation

AEMO notes Infigen Energy's concern about the lack of information about future operation and maintenance costs. Section 9.2 of the IPFRR was designed to offer Affected Generators an opportunity to seek a variation to the PFR Settings applied to their Affected GS.

This has now been moved to section 7.7 and made clear that Affected Generators can re-apply if new facts or evidence emerge after the initial implementation of the PFR Rule.

Capability limited to OEM specification

The PFR Rule as a whole is predicated on the use of existing capability in the NEM to correct frequency deviations under normal operating conditions.

AEMO considers that the range of standing variations now included in section 7.6 of the IPFRR, and Affected Generators' ability to seek plant-specific variations, should make it clear that the PFR Rule does not require Affected GS to be operated beyond their capability, as originally specified by the OEM or, as appropriate, a suitable consulting engineer.

AEMO notes that the design capability of a generating system is not necessarily the same as its historical performance settings.

In the example provided by AGL, a droop setting of 4% would meet the requirement in section 3.3 of the IPFRR and would not need to be altered or be subject to an application for variation.

4.7.3. AEMO's conclusion

AEMO has:

- Amended and restructured section 7.1 of the IPFRR to reflect its intention and the PFR Rule better.
- Deleted section 9.2 and replaced it with a new section 7.7 to clarify that applications for exemption or variation can be made in the future.

4.8. Usurpation of FCAS markets

4.8.1. Issue summary and submissions

Questions around the FCAS markets and the provision of PFR remain to be addressed as part of the AEMC's consultation on the Removal of disincentives to primary frequency response rule change proposal.

Nevertheless, three submissions, in particular, commented that, by requiring the provision of PFR outside the normal operating frequency band (NOFB), AEMO is usurping FCAS.

Delta Electricity submitted:

> Delta Electricity maintains a present viewpoint that PFRR delivery required by the new Rule does not authorise the PFRR to specify droop response beyond NOFB limits. The NOFB limits are the defined widest initiation limits for commencement of market services i.e. contingency FCAS. It is Delta Electricity's opinion that contingency FCAS delivery, which makes use of energy stored for its purpose,

> the same energy to be used for PFR on Vales Point Units, ought to already include PFR required beyond the NOFB. If not already being prepared for by AEMO, further adjustments for pre-dispatch volumes for 6/60s FCAS are recommended. Whilst Delta Electricity also considers that PFR delivery is more similar in concept to regulation FCAS, the present FCAS regulation system dispatched by AEMO to Vales Point cannot deliver "fast-acting" PFR because of its delivery with the energy dispatch as a single combined target and only reflective of slower time-error corrections as the AGC determines. An additional regulation response delivered as a separate signal to a power station DCS could make use of the stored energy used for contingency services and provide "fast-acting" PFR. However, this change would need FCAS controller redesigns in Unit DCS not catered for in the PFRR rule change.
>
> …
>
> AEMO have stated that PFR is to exist in an unlimited amount regardless of the NEM dispatch of Contingency FCAS. Delta Electricity considers this to be overreach in the mandatory PFR rule application and that the range of response should be limited by droop definition and measured reaction between the assigned deadband and the normal operating frequency band (NOFB) where AEMOs NEM dispatched FCAS controls should be adequately prepared to include for PFR outside of the NOFB. Any more response from PFRR beyond the NOFB is overreach into the competitive FCAS 6s market which, under separate Rules that detail the objectives of MASS and specifically FCAS, are also required to maintain system security.
>
> For example, on a system that can achieve the PFCB and assuming AEMOs PFRR maintains frequency to the PFCB most of the time, the above Droop reaction may equate to a maximum of 135mHz of response. PFR required beyond these deviations ought to be prepared for and delivered by FCAS services.
>
> However, effective raise PFR (ie. fast-acting) responses under the PFRR will also be zero on Units with no pre-prepared stored energy.
>
> It is also the function of a well-designed proportional controller to observe the assigned droop equation and only deliver the proportional MWs relevant to the detected frequency (or speed) variation. The droop characteristic and its relationship to the detected deviation in frequency or speed is itself a limiter of the range of response for each given deviation.
>
> …
>
> PFR is also provided by Market Ancillary services. Requiring response times to be assessed against 0.5Hz frequency changes is overreach and the maximum expected PFR obligation should be limited to the reaction required from the PFCB to the NOFB, i.e. a 135mHz change at most. Sudden movements larger than this amount must by Rules definitions be engaging MASS FCAS controls that AEMO should be dispatching to include for PFR beyond the NOFB.

ERM Power submitted:

> Also, we request further clarity with regards to section 4.2 with regards to the requirements for the Affected GS to provide PFR outside the Normal Operating Frequency Band (NOFB) based on the following;
>
> AEMO in its rule change request indicated that;
>
> > "The decline in the primary frequency response (PFR) of generating systems has resulted in this lack of effective frequency control within the normal operating frequency band,"
>
> Consistent with the argument of requiring mandated PFR to improve frequency within the NOFB, AEMO argued that the cost impact for the provision of mandatory PFR within the NOFB on an individual generator would be small.
>
> > "If all capable scheduled and semi-scheduled generation in the NEM were required to provide PFR in accordance with AEMO's specifications, all the objectives of this rule would be met with lowest impact on the operation of each affected Generator."
>
> This was further supported by the submission by AEMO of a case study detailing dispatch deviations for five generators over a 24 hour and 7-day period in the Western Australia Electricity Market (WEM).

The Australian Energy Market Commission (the Commission), in its Final Determination to the rule change request, accepted AEMO's arguments that the provision of a widespread requirement for the provision of mandatory PFR on all registered generating units in the NEM would result in only small cost impacts on individual Affected GS.

> "The Commission accepts the views expressed by AEMO in its rule change request and supported by its expert advice that a mandatory requirement for primary frequency response applied to a broad cross-section of the generating fleet would mean that costs incurred by each individual generator would likely be minimised. If every scheduled and semi-scheduled generator provides primary frequency response then this will minimise the costs for each individual generator, since no one generator will bear the burden of responding — instead, this will be shared across the entire fleet."

Further, AEMO in its rule change request acknowledge that the provision of PFR in the National Electricity Market (NEM) outside the NOFB is already provided by procurement by AEMO of contingency frequency control ancillary services (FCAS);

> "Contingency FCAS when delivered from a proportional controller is a form of PFR, albeit with a very wide zone of insensitivity not seen in other comparable power systems."

This was also acknowledged and agreed to by the Commission in the Final Determination;

> "Under current arrangements, PFR is provided by fast and slow contingency FCAS services that operate outside the normal operating frequency band (NOFB). The NOFB is defined in the frequency operating standard as 49.85 Hz — 50.15 Hz. PFR may also be voluntarily provided by generator governor response and active power control within the NOFB. Providers of PFR within the NOFB are not directly paid for being frequency responsive".

In considering the above, it should be noted that AEMO only procures sufficient contingency FCAS response to restore power system frequency to within the NOFB, not to return power system frequency to close to 50 Hertz.

The Rules indicate in several sections the importance of FCAS procurement to the management of power system frequency.

> "Ancillary services are services that are essential to the management of power system security, facilitate orderly trading in electricity and ensure that electricity supplies are of acceptable quality." [clause 3.11.1(a)]
>
> "AEMO may give dispatch instructions in respect of scheduled generating units, semi-scheduled generating units, scheduled loads, scheduled network services and market ancillary services pursuant to rule 4.9;" [clause 4.4.2(a)]
>
> "AEMO may at any time give an instruction (a dispatch instruction) to a Market Participant which has classified one or more of its generating units or loads as an ancillary service generating unit or an ancillary service load:
>
> (1) stating that the relevant generating unit or load has been selected for the provision of a market ancillary service;
>
> (2) stating the market ancillary service concerned; and
>
> (3) nominating the range to be enabled." [clause 4.9.3A(a)]

AEMO is also required to ensure that in meeting its requirements under 4.4.2(a) that;

> "AEMO must use reasonable endeavours to arrange to be available and allocated to regulating duty such generating plant as AEMO considers appropriate for automatic control or direction by AEMO to ensure that all normal load variations do not result in frequency deviations outside the limitations specified in clause 4.2.2(a);"

where 4.2.2(a) indicates that;

> "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;"

> Given that the amended rule stipulates that AEMO may not require an Affected generator to maintain stored energy, headroom or foot room, (included in the definition of headroom), to ensure the provision of mandatory PFR,
>
> > "The Commission has specified in the final rule that the PFRR cannot require generators to maintain additional headroom or stored energy for the purpose of providing primary frequency response. The Commission acknowledges that AEMO did not propose to include a requirement in the PFRR that generators maintain headroom as part of its proposed rule"
>
> it is unclear to ERM Power how section 4.2 may require the provision of mandatory PFR outside the NOFB given AEMO's and the Commission statements that; the provision of mandatory PFR is only expected to require small deviations from dispatch targets and incur minimal costs, and seek clarity from AEMO regarding this. From ERM Powers perspective we are concerned that the provision of mandated PFR should not be the case for large power system frequency excursions outside the NOFB and doing so place providers of mandatory PFR outside the NOFB at a commercial disadvantage to service providers paid for the provision of PFR via the contingency FCAS markets. Provision of PFR outside the NOFB would not in our view result in the minimisation of costs on these Affected GS as set out in the rule change request and Final Determination.

CS Energy submitted:

> CS Energy would have preferred AEMO to adopt a holistic approach to the development of the Interim PFRR to ensure consistency with Market Ancillary Service Specifications (**MASS**), Frequency Control Ancillary Services (**FCAS**), Frequency Operating Standards (**FOS**), Generator Performance Standards (**GPS**), wide band frequency response and associated Rules.
>
> CS Energy recognises the challenge faced by AEMO in delivering a technical engineering concept that is coupled with a market mechanism and then overlayed with legalese. Unfortunately, what arguably should have been a relatively straightforward process has, in CS Energy's view, turned into an unnecessarily complex bureaucratic process.
>
> …
>
> CS Energy would also like further clarity on section 4.2 Range of Response, relevantly the expectations for the Affected GS to provide PFR outside the normal operating frequency band (**NOFB**) as defined in the FOS. This is important as the NOFB represents the interface and domain of the FCAS contingency market. The final Rule expressly provides that the PFRR must not require the Affected GS(s) to provide headroom or footroom for the purpose of providing PFR. CS Energy does not view the PFRR as displacing the FCAS market or the provision of mandated wide band frequency response.

4.8.2. AEMO's assessment

At present, FCAS are services that AEMO acquires through spot markets and the specification of each FCAS is contained in the market ancillary service specification (MASS).

There are, essentially, two types of FCAS:

1. Contingency FCAS – This can only must be provided after power system frequency exits the NOFB upon the occurrence of a contingency event and is designed to assist AEMO in meeting certain requirements of the FOS. It is not designed to play any role in controlling power system frequency under normal operating conditions. There are six sub-types of Contingency FCAS, distinguished by speed of response and whether they are addressing a rise or fall in power system frequency.
2. Regulation FCAS – This provides a secondary response under normal operating conditions and relies on a centralised signal (AGC) before a generating system will response to frequency deviations. It is intended to allow for the control of power system frequency close to the normal level of 50 Hz in the absence of any disturbance but is capable of doing so only when supported with adequate PFR. There are two sub-types of Regulation FCAS, distinguished by whether they are addressing a rise or fall in power system frequency.

Participation in the FCAS markets is voluntary and subject to strict compliance obligations. When registered to provide FCAS, Generators are required to provide the service for which they are registered and in accordance with their bids. AEMO pays for the provision of the service bid by a Generator because, effectively, they could be required to curtail or operate their generating systems to a sub-optimal level to do this.

Unlike Contingency FCAS and Regulation FCAS, the provision of PFR under the PFR Rule will not be limited to when Affected GS are enabled. Clause 4.4.2(c1) states that, subject to clause 4.4.2A(c) (which deals with AEMO's allocation of regulating duty to generating plant):

> each *Scheduled Generator* and *Semi-Scheduled Generator* that has received a *dispatch instruction* to generate a volume greater than zero MW must operate its *generating system* in accordance with the *Primary Frequency Response Requirements* as applicable to that *generating system*;

While no impact on existing operating practices in relation to the management of Contingency FCAS obligations is intended, it cannot be ruled out. The more that stable control of power system frequency closer to 50 Hz is achieved, as intended by the PFR Rule, the more remote the possibility of any potential impact of this issue on Contingency FCAS.

AEMO notes that it has recently amended the market ancillary services specification to recognise any impact on Contingency FCAS delivery by the PFR Rule.

Clause 4.4.2A(c)(1) of the PFR Rule explicitly states that Affected Generators do not need to store energy to provide PFR to meet the requirements of the PFR Rule, as they may currently do when enabled for the provision of Contingency FCAS. AEMO does not consider that either the PFR Rule, or anything in the AEMC's PFR Rule determination, implies a prohibition on any possible provision of PFR outside of the NOFB.

4.8.3. Importantly, AEMO is still required under the NER to continue to enable sufficient Contingency FCAS to meet all the requirements of the FOS. In determining Contingency FCAS requirements, AEMO will continue to disregard any 'free' PFR, as has always been the case. AEMO expects the FCAS markets to continue to operate as designed, and to continue to fulfil the roles for which they were designed, although perhaps additional capable providers might choose to register to provide Contingency FCAS. AEMO's conclusion

AEMO has determined not to make any change to the IPFRR as a result of the submissions made on this issue.

4.9. Impact on generator performance standards (GPS)

4.9.1. Issue summary and submissions

A range of issues was raised during the forums on GPS, relating to Consulted Persons' concerns about reopening Affected GS' GPS. Only AGL Energy submitted on this issue directly, while Vestas addressed more technical concerns.

The issues raised can be summarised as follows:

1. Scope of impact on GPS.
2. Whether clause 5.3.9 applies.
3. Application of clause S5.2.2 process.
4. The need for modelling Affected GS performance.
5. Whether renewable generation will require storage.
6. Whether Affected Generators with renewable generation will be remunerated to preserve project economics.

AGL Energy submitted:

> AGL strongly supports the exclusion of clause 5.3.9. We do remain concerned that AEMO may trigger other related elements of the NER when a generator makes modifications to implement PFR. Given the potential costs and regulatory burden involved with certain NER mechanisms, the PFRR should provide detailed guidance on when AEMO is likely to:
>
> - seek changes to generator performance standards;
> - seek to apply the settings change process in S5.2.2; or
> - require a generator to undertake some form of modelling outside the provisions of clause 5.3.9.
>
> Finally, where the changes necessary for a generator to implement PFR would have triggered the clause 5.3.9 process, it would be useful for the PFRR to clarify AEMO's expectations regarding implementation.

Vestas submitted:

Mandatory underfrequency response

Automatic access standard requirement for Frequency control	**Recommended PRIMARY FREQUENCY RESPONSE**
(1) The *generating system's power* transfer to the *power system* will not: (ii) decrease in response to a fall in the *frequency* of the *power system* as measured at the *connection point*; and (2) The *generating system* is capable of operating in *frequency response mode* such that it automatically provides a proportional: (ii) increase in *power* transfer to the *power system* in response to a fall in the *frequency* of the *power system* as measured at the *connection point*, sufficiently rapidly and sustained for a sufficient period for the *Generator* to be in a position to offer measurable amounts all market ancillary services for the provision of power system frequency control.	Mandatory underfrequency response where: • (3.4. Response time) an Affected GS should be capable of achieving a 5% change in active power output, within no more than 10 seconds, resulting from a sufficiently large positive or negative step change in frequency greater than the Affected GS' Deadband and less than or equal to 0.5 Hz. • (4.3. Continuity of Response) PFR must remain continuously enabled at the PFR Settings, unless agreed with AEMO, independent of ancillary services enablement.

Droop

Automatic access standard requirement for Frequency control	**Recommended PRIMARY FREQUENCY RESPONSE**
(4) (ii) the droop can be set within the range of 2% to 10%.	(3.3. Droop) For all Affected GS, Droop must be set to less than or equal to 5%

…

Vestas recommendations:

- Remuneration for generators providing PFRR services should be considered to ensure the renewable energy project economics are not adversely impacted.
- Keep the adjustable range of droop between 2 and 10% and use 5% as default as some grid connection points may require higher droop than 5%.

4.9.2. AEMO's assessment

General

In general terms, the GPS for a generating system establish its minimum performance capabilities. In many cases, however, including in relation to frequency response, the GPS only specify a certain level of plant capability, not actual real-time performance obligations.

The IPFRR establish Affected GS' real-time performance obligations based on capabilities described in clause S5.2.5.11 of the NER, in a way that the GPS currently do not. Given the nature of GPS, it is to be expected that (particularly for older Affected GS), the performance capabilities documented in the GPS will be less onerous than the obligations required by the IPFRR, even where an Affected GS' actual capability is sufficient to meet the IPFRR (fully or substantially).

For some newer Affected GS, their GPS under clause S5.2.5.11 of the NER are more specific and, in some cases, specify performance requirements, settings or other arrangements that could conflict with the requirements in the IPFRR.

Scope of impact of PFR Rule on GPS

AEMO envisages that it will only be necessary to update the GPS for the clause S5.2.5.11 performance standard solely to remove any inconsistency with the IPFRR.

AEMO does not see a need to reassess the capability of plant in relation to any other GPS, particularly those under clause S5.2.5.7 and S5.2.5.8 of the NER. To recognise and resolve any potential conflict between these two GPS and the requirements of the PFRR, AEMO has expressly included the limits of these two GPS as standing variations in section 7.6 of the IPFRR.

AEMO intends to meet with Network Service Providers (NSPs) to ensure a common understanding of how the PFR Rule interacts with existing GPS, and for new Affected GS, how the relevant capability is to be incorporated in their GPS.

Application of clause 5.3.9

Clause 5.3.9(a1) explicitly disapplies the clause 5.3.9 process where Affected GS are being modified to comply with the PFRR which, by implication, includes the IPFRR.

Application of clause S5.2.2 process

The process proposed in the IPFRR, effectively, meets the requirements of clause S5.2.2 of the NER.

The need for modelling Affected GS performance

Where the material changes required to comply with the IPFRR are confined to governor or plant load controller deadbands, load limiters, or distributed control systems, AEMO will not require additional modelling studies for the purposes of verifying the changes made to Affected GS' control system settings. The evidence requirements are set out in section 8.2 of the IPFRR.

Droop settings higher than 5% could potentially be sought by Affected Generators as a variation, although AEMO is not aware of examples where they are required.

Whether renewable generation will require storage

No Generator impacted by the PFR Rule needs to maintain any headroom (or 'foot-room'). The management of minimum economic levels of guaranteed headroom (and foot-room) will continue to be performed through the FCAS markets, however, where an Affected GS, incidentally, has either headroom (or foot-room) and can safely and stably provide PFR using that headroom (or foot-room), it should do so.

Preservation of project economics for renewables

The PFR Rule only considers the issue of cost is in the context of exemptions and variations. See section 4.7 of this Report for further discussion of this issue.

4.9.3. AEMO's conclusion

AEMO has determined not to make any change to the IPFRR as a result of the submissions made on this issue. AEMO will be contacting each Affected Generator whose GPS might require review and update and will discuss implementation of the PFR Rule with NSPs to ensure a smooth implementation.

The only GPS where changes might be required is the one under clause S5.2.5.11 of the NER.

4.10. Alternatives to step response tests

4.10.1. Issue summary and submissions

Several Consulted Persons raised questions during the forums about alternatives to the step response tests required by draft section 8 of the IPFRR. The alternatives suggested are as follows:

- Where an Affected GS has operated recently with settings that are identical, or very similar, to those required by the IPFRR.
- Extensive recent testing carried out on the Affected GS for reasons unrelated to the PFR Rule.
- Trip-to-house load tests.

The only submission on this issue was from Hydro Tasmania:

> **Verification of machine response performance**
>
> Hydro Tasmania agrees with AEMO that there is a need to verify the machine response performance after tightening governor deadbands (as described in Section 3.4 of the PFRR document). **However, implementing the proposed systematic approach across Hydro Tasmania's generation fleet would potentially be logistically very difficult, time consuming and expensive**. This is due to the large number of generation assets within our portfolio, and the geographic and technological diversity of our generation fleet.
>
> ….
>
> **Hydro Tasmania therefore requests that AEMO gives further consideration to alternate verification methods and/or ways that testing can be carried out in the most efficient manner**. As an example of an alternative approach, the data captured during the frequency control trials undertaken in Tasmanian in collaboration with AEMO and TasNetworks could be used to form the basis for verification of machine response performance. The results of these trials, including the machine response captured by the high speed governor data logging, detailed monitoring of guide vane movements and the overall system frequency improvements in Tasmania have already been provided to AEMO. Additionally, Hydro Tasmania is currently undertaking an extensive and ongoing program to upgrade our governor control systems. In the event that these assets are scheduled for an upgrade in the next two years, Hydro Tasmania would like to request a deferral of the PFR performance verification obligations until the new governor control system is commissioned.
>
> Noting the actions already taken by Hydro Tasmania, any potential delay in verification of some generating units in Tasmania is unlikely to materially impact on the management of power system frequency. Hydro Tasmania would welcome the opportunity to discuss verification requirements further with AEMO to ensure verification requirements are met in the most practical and efficient way possible.
>
> …
>
> **PFR response verification for identical machines**
>
> For machines sharing the same waterway, identical primary rating and governor settings, Hydro Tasmania seeks AEMO's agreement for single machine performance results to be used to represent all

the like units. Based on experience, Hydro Tasmania would expect the performance difference to be negligible.

PFR verification based on simulation

Given the diversity of the generating portfolio, as a supplementary approach, Hydro Tasmania requests consideration be given to the possibility of using simulated test results for PFR verification wherever is possible.

4.10.2. AEMO's assessment

AEMO's primary concern in requiring step response tests is to ensure the stable operation of Affected GS when operating with the PFR settings. A staged test is an accepted and effective method of demonstrating this, however, it is acknowledged that it can be disruptive, and consumes time and resources.

Where alternative methods of demonstrating plant stability with the proposed PFR settings are available, the IPFRR has been updated to allow for them, in particular, the provision of recent and comparable test data as an alternative is now acceptable.

In Tasmania, a number of Affected GS have already recently (temporarily) operated with settings consistent with the requirements of the IPFRR and demonstrated stable operation under those conditions. This recent evidence would be adequate to demonstrate the use of those settings again.

Where an upgrade of governor control systems is proposed in the near future, Affected Generators could seek a variation from AEMO to defer tests or other verification.

It is also noted that where multiple identical machines have identical settings applied, there is reduced benefit in testing of each machine individually, except, perhaps, to confirm whether the settings have been applied correctly. In this case, the results of testing only of one of these identical machines would be acceptable.

The suggestion of trip to house load tests as an alternative type of test is not practical because it involves the disconnection of a generating system from the power system. PFR is required while the generating system remains connected and synchronised.

Finally, simulation is not being considered as an option because there is a need for a physical test, or experience to demonstrate stability. In this instance, simulations cannot provide sufficient confidence in the stability of response following changes to Affected GS' settings.

4.10.3. AEMO's conclusion

AEMO has amended section 8 of the IPFRR to include a new section 8.2.3 accepting the following as alternatives to a step response test:

- Where an Affected GS has recently operated with settings that are identical, or very similar, to those required by the IPFRR, evidence of stable operation while operating with those settings.
- Recent suitable testing sufficient to demonstrate that operating the Affected GS with the PFR settings will result in stable operation.
- The IPFRR now also notes that where identical settings will be implemented on multiple identical generating units, a demonstration of stable operation of only one of these units, by test or other means, would be required.

4.11. Staged Implementation

4.11.1. Issue summary and submissions

During the forums held as part of this consultation, AEMO suggested that implementation could be effected in two stages, whereby those Affected GS would be subject to a gradual tightening of their deadbands in two steps might be appropriate. The reaction during the forums was mixed and only some submissions referred to this issue.

CS Energy submitted:

> Section 3.2 of the draft Interim PFRR provides:
>
> > "Each Affected GS must provide PFR outside the Affected GS' Deadband, which must be no wider than the [primary frequency control band (PFCB)]."
>
> CS Energy notes that Rule 4.4.2A(b)(1)(i) as inserted by the final Rule specifies that the PFCB is the lower bound that AEMO may require the governor deadband setting for an Affected GS rather than the maximum allowable setting. Given that such a narrow deadband is unprecedented in the NEM, CS Energy is disappointed that from implementation AEMO has chosen to set the PFCB at this lower boundary rather than a staged narrowing of the PFCB.

Delta Electricity submitted:

> Cautious adjustments towards tighter deadbands required for a Unit are recommended particularly on Units such as Vales Point where the overall governing system is made up of control sub-systems. Deadbands of sub-systems that provide optimum stability of a Unit and the Network should be favoured over deliberate and strict matching of deadbands of a sub-system of a Unit to the equivalent of the PFCB. The pursuit of a common overall governing deadband on Units with interconnected governing sub-systems that must coordinate to avoid instability is not just a simple matter of setting deadbands of the subsystems to the equivalent of the PFCB.
>
> Delta Electricity also recommends staged and coordinated implementation of tighter dead bands so that the PFR delivery is evenly shared between participants. Generators in the NEM should not be required to control frequency more sensitively than a competitor without being compensated for it. As part of mandatory PFR Rules implementation, the development by AEMO of a system that recognises superior PFR delivery and compensates superior performance is recommended. An eventual market solution that includes this recognition but also procures only the minimum amount required to produce the quality of frequency control the NEM requires at any given moment remains Delta Electricity's preferred long-term system.

Alinta Energy submitted:

> As outlined in past submissions, the decision to mandate frequency control to a (±0.015) Hz dead band setting is physically untested in the NEM and implementing such a narrow dead band setting requirement rapidly would likely introduce several risks that may have unintended implications on the NEM's operating state.
>
> As such, Alinta Energy supports AEMO's prudent decision to include the progressive step change allowance as outlined in section 5.1(b), allowing for a reduction in dead band settings commencing with (±0.050) Hz.
>
> This approach will allow participants and AEMO to progressively monitor the performance of frequency of the NEM as it adheres to the new dead band setting requirement. Upon close consideration of what impact the initial step change has on the network, it may be found that the proposed second step change requirement to (±0.015) Hz actually not required.

4.11.2. AEMO's assessment

AEMO had indicated a preparedness to implement a progressive narrowing of Affected GS deadbands, which will be centrally co-ordinated by AEMO once the results of the Self-Assessments have been reviewed but not all Consulted Persons welcomed the idea.

For this reason, section 5.1 of the IPFRR and Appendix A, containing the pro forma Self-Assessment, provide Affected Generators with an option of a one-, or two-stage implementation.

Delta's suggestions regarding payment for superior service are best addressed to the AEMC in its consultation on the Removal of disincentives to primary frequency response rule change proposal.

4.11.3. AEMO's conclusion

AEMO has determined not to make any change to the IPFRR as a result of the submissions made on this issue.

4.12. Implementation timeline

4.12.1. Issue summary and submissions

In summary, the issues raised by Consulted Persons were:

1. Implementation timetable as a whole.
2. Some of the deadlines are too tight.

Delta Electricity proposed an alternative timetable for AEMO:

> It is recommended the interim PFRR include example timeframes for the process from self-assessment through to implementation be included as a further appendix. An example is below:

Process Step	**Permitted Period**	**Total elapsed period**
Participant Self- Assessment	60 business days	60 business days
AEMO request for more information	5 business days	65 business days
Participant supply of more information - Extension of time request	5 business days	70 business days
AEMO grants extension of time 15 business days	(not specified; assumed) 5 business days	75 business days
Participant supplies extra information and PFR variation form	15 business days	90 business days
AEMO PFRR Variation consideration – Further information needed	10 business days	100 business days
Participant supply of more information for the variation - Extension of time request	10 business days	110 business days
AEMO grants variation information extension of time 15 business days	(not specified; assumed) 5 business days	115 business days
Participant Variation – Further information supplied	15 business days	130 business days
Implementation wait time (to suit AEMO NEM-coordinated implementation)	(not specified) 20 business days	150 business days
Implementation to 50mHz - Tested	(not specified; assumed but dependent on actual event) 5 business days	155 business days
Implementation to final Deadband wait time (to suit AEMO NEM-coordinated implementation)	(not specified) 60 business days	215 business days
Implementation to final adopted deadband - Tested	(not specified; assumed but dependent on actual event) 5 business days	220 business days

Infigen Energy submitted:

> AEMO should clarify the explicit dates and timelines for implementation (rather than relative days, where possible).
>
> AEMO's expectation of a 5-business day turn-around to queries from AEMO is unrealistic. For example, if the OEM needs to be contacted, this would be unachievable even under normal global business conditions. Infigen suggests given the potential complexity, a 20-business day timeframe (in line with AEMO's timeframe) is necessary. While AEMO has suggested that participants should already have all answers on hand, this is not realistic. Equipment that was not specified, nor designed to provide these services may require more extensive investigations and/or studies. Infigen does not accept that extensions can only be at AEMO's sole discretion; a negotiated framework is required.

Origin Energy submitted:

> **Timelines should be flexible to account for potential compliance issues and the expectations for generators should be clear**
>
> Origin considers the timeline for the first tranche of generators (i.e. those > 200 MW) to comply with the PFRR is tight, and that some flexibility is required as both plant operators and AEMO adjust to the new requirements. …
>
> This flexibility should extend to the 10 business days generators will have to respond to any follow up questions after a self-assessment. Delays could occur where a generator is required to contact the Original Equipment Manufacturer (OEM). Given the technical nature of the issues, it is possible the OEM would not be able to provide a complete response within the prescribed timeline. Origin therefore suggests that the PFRR makes allowances for circumstances such as these, which are outside the control of the generators.
>
> To improve clarity, the PFRR should specify that generator self-assessments of capability can be based on historical data such as previous tests or measured response to events, consistent with footnote 4 of Appendix A. Additional guidance on the level of detail that generators need to be provided for self-assessments would also be welcomed.

4.12.2. AEMO's assessment

General

AEMO's aim is to have as many Affected GS operating with PFR settings as possible before summer 2020-21, particularly generation from Tranche 1 (those with a capacity of more than 200 MW).

Changing Affected GS' settings during the summer high demand period carries increased risk and is much less likely to be achievable, which means that the next opportunity to effect changes will be March 2021. AEMO expects to use any hiatus over summer to resolve issues with Affected GS that might require time to resolve before they can be ready to provide PFR.

Therefore, AEMO expects those Affected GS that can provide PFR with minimal changes to their control systems and likely will not require tests to be the first group to be ready to provide PFR by summer.

Implementation Timetable

Clause 11.122.2(c) of the PFR Rule requires the IPFRR to, amongst other things:

> (3) set out the process for the coordinated activation of changes to *generating systems*, including the date (which may vary according to *plant* type) by which *Scheduled Generators* and *Semi-Scheduled Generators* must effect changes to their *plant*, to comply with the Interim Primary Frequency Response Requirements.

Attempting to create a specific timetable has been a challenging aspect of the IPFRR because AEMO envisages that the results of the Self-Assessment will be determinative of the next steps, in particular how AEMO will go about requesting changes to Affected GS' control settings to achieve the PFR settings required. While Delta Electricity's proposed timeline provides a high-level overview of a process to achieve implementation, in reality there will be several workstreams resulting in implementation at different dates/times.

In all, this makes the creation of a fixed implementation timetable unrealistic. The timetable is necessarily dynamic and will need to be updated regularly.

Deadlines

In selecting the deadlines, AEMO considered how the application for registration timeframes are set out. The timelines are just as tight but far more extensive, in terms of the material that an applicant for registration as a Generator could be required to provide to AEMO.

Leaving deadlines to the uncertainty of negotiation is untenable given the imperative to achieve a step change in the improvement of power system frequency performance by summer 2020-21.

Any delays, where unavoidable, can be addressed through ad hoc applications for extensions for the provision of information or data, or variation to implementation deadlines.

4.12.3. AEMO's conclusion

AEMO has outlined an indicative implementation timeline for Tranche 1 in Appendix G of the IPFRR, noting that it will be updated regularly during implementation and published on its website.

Key dates in this timeline will depend on the eventual results of Self-Assessments. As noted elsewhere, it is AEMO's intention to coordinate implementation closely with Affected Generators, particularly those in Tranche 1.

AEMO has deliberately allowed for significant flexibility in implementation, where this will be required. The need for an urgent, significant improvement in power system frequency performance, however, dictates some stringency around deadlines.

4.13. Impact of COVID-19 on implementation

4.13.1. Issue summary and submissions

COVID-19 was raised by some Consulted Persons as a justification for extending implementation in a variety of ways. The issues raised can be grouped as raising potential delays due to:

1. Reliance on third parties for information to complete the Self-Assessments.
2. Travel restrictions.
3. Restrictions on fieldwork.

Alinta Energy submitted:

> The impact of COVID-19 has introduced extraordinary changes to Australia's communities and economy. In response, Alinta Energy has ramped up our resourcing capabilities to deliver and provide support for homes and businesses.
>
> The implementation of the mandatory frequency control rule change is currently requiring significant time and resources from Alinta Energy and key operational staff on site at power stations. Scheduling engineering feasibility studies, undertaking risk assessments, doing testing and physically making any required changes to generation plant takes significant time.
>
> From a resourcing perspective, many key experts required to consult on and implement dead-band setting changes can only be sourced from overseas or interstate. With the current Government imposed international/domestic travel restrictions and site restrictions limiting contractors on site, this is an extremely challenging rule change to implement.

> Alinta Energy urges AEMO to consider delaying the rule change implementation schedule to allow for industry to plan and provide appropriate operational flexibility to be built into individual generator's PFRR forward work plans.

ERM Power submitted:

> Given the need to acquire a high level of technical assistance in determining the inherent technical capability of the generating units and also the internal engineering resource that will be required for commissioning and testing at a time when COVID-19 is resulting in reduced capability in these areas, we recommend AEMO consider an additional blanket extension of 40 business days to the timeframes set out in Table 2.

Stanwell submitted:

> The current COVID-19 restrictions may limit the ability of Original Equipment Manufacturers (OEMs) to provide evidence on unstable operation, which could result in a delay of generators submitting their self-assessment.

CS Energy submitted:

> CS Energy recommends AEMO considers an extension to the time frames detailed in section 5, Table 2 to acknowledge the impact of COVID-19. COVID-19 is already and will continue to impact availability of technical expertise and mobilisation of internal engineering services to enable the required assessment, commissioning and testing to implement the PFRR on the Affected GSs in the CS Energy portfolio.
>
> CS Energy understands AEMO's approach to any delay of the implementation of mandatory PFR is to address this in its response to each Affected GSs application. However, this does not consider the impact that COVID-19 may have on a generator's ability to undertake the assessment. This self-assessment is due by the date specified in section 5, Table 2. While a generator can apply for an extension of this date, this is an unnecessary diversion of resources at a critical time when Participants are seeking to otherwise manage the impact of COVID-19 on their operations.

Hydro Tasmania submitted:

> **Verification of machine response performance**
>
> … These challenges will be exacerbated by the ongoing COVID-19 pandemic, and associated limitations and constraints on Hydro Tasmania's resourcing.

Origin Energy submitted:

> Additionally, the disruption due to COVID-19 should also be taken into consideration including where travel restrictions limit the movement of critical staff or contractors.

4.13.2. AEMO's assessment

General

While AEMO acknowledges that COVID-19 carries the risk of increased difficulty for some Affected Generators in implementing the changes required, it is not clear that this issue would be substantive enough to require a delay in implementation. The materiality of this issue will not be known until AEMO has received a sufficient number of Self-Assessment results.

Where a single Affected Generator was perhaps unavoidably delayed on a single Affected GS due to COVID-19, this could, potentially, be dealt with by the Affected Generator applying for a variation. A delay in implementation for an Affected GS in one of the later tranches would be a different matter to delays for larger generation in Tranche 1.

The current process for implementation allows for flexibility in implementation dates, if required. The timetable for an Affected Generator to undertake a Self-Assessment also has some allowance for unavoidable delays, however, it is important that it is undertaken in a timely manner, where reasonably possible.

AEMO's experience since the first draft of the IPFRR was published many months ago is that some Affected Generators who have chosen a proactive approach have already achieved significant progress towards undertaking their Self-Assessments and determining appropriate PFR settings.

Reliance on third parties for information

As indicated on numerous occasions during the forums, delays to the provision of information by third parties, such as OEMs can form the basis of an application for an extension of time. Moreover, it is AEMO's expectation that Affected Generators would not have waited until 4 June 2020 before contacting third parties who hold relevant information for the Self-Assessments.

Travel restrictions

AEMO understands that there are some Affected Generators who might need to access expert engineering assistance from parts of the country or the world where travel is simply not possible. These issues can be identified as part of their Self-Assessment and applications made for variation to the implementation of the PFRP to their Affected GS.

Disruption to fieldwork

Where fieldwork is necessary to make changes to Affected GS, Affected Generators need to apply for variation to the implementation of the PFRP to their Affected GS.

4.13.3. AEMO's conclusion

AEMO does not consider there is a need to delay implementation by reason of COVID-19, as there is sufficient flexibility in the proposed process to address individual issues.

AEMO has determined not to make any change to the IPFRR as a result of the submissions made on this issue. Instead, it will manage issues on an ad hoc basis through variation applications.

4.14. Publication of more detail on Affected GS settings

4.14.1. Issue summary and submissions

Delta Electricity considered that AEMO's published list of variations granted in respect of the PFRP should include the detailed parameter values approved by AEMO. Delta Electricity raised this issue both during the forums and in its submission, which stated:

> It is recommended that Deadband values agreed to by AEMO as variations should be listed against Units to ensure fairness in application is transparently comparable between Units of similar design and technology.
>
> Delta Electricity considers that the National Electricity Objective requires that if a particular plant in a local region cannot achieve the tightness of overall deadband of +-15mHz and a larger deadband is agreed by AEMO to apply at that plant then, in the interests of fair competition in the application of a mandatory Rule, other plant of similar technology in the same jurisdiction should be advised and permitted to relax any relevant part of a complex controller to be no narrower than the deadband permitted by AEMO for the nearby competitor. An alternative to this approach would be for AEMO to develop a compensation process for superior performance.

4.14.2. AEMO's assessment

Information about the control system settings of generating systems is generally considered to be confidential information under the NER.

The control system settings information that AEMO will be receiving from Affected Generators as part of the Self-Assessments is information that AEMO was entitled to receive when the Affected GS were first connected to the power system, and which needs to be kept up to date. This information was first provided under various provisions in Chapter 5 of the NER when the Affected Generator was a Connection Applicant and considered to be *confidential information* under clause 5.3.8 and S5.2.4.

Even if the Affected GS predates the NER, information about the control system settings of generating systems needs to be kept up to date under various provisions in Chapter 5 of the NER.

AEMO also notes that the grant of exemptions and variations depends on a number of factors, including financial information, which is confidential under clause 4.4.2B(c) of the NER. Not all generation of similar age and technology will have comparable financial positions.

Delta Electricity's proposed alternative compensation scheme is not within the scope of the NER as amended by the PFR Rule. This may be addressed by the AEMC in its consultation on the Removal of disincentives to primary frequency response rule change proposal.

4.14.3. AEMO's conclusion

Publishing details of Affected GS' control system settings values would disclose information that is, or could be, confidential and is not contemplated by clause 4.4.2A(d) of the PFR Rule. Accordingly, AEMO is unable to publish those details without further changes to the NER.

Instead, AEMO has amended Appendices D and E of the IPFRR to provide an option for each Affected Generator applying for exemption, or variation, to consent to the publication of more granular data related to their exemption or variation, if granted.

5. OTHER MATTERS

5.1. AEMO's other remedial action to address deterioration of frequency control under normal operating conditions

5.1.1. The Issue

While not strictly within the scope of the consultation, Delta Electricity submitted that AEMO should focus on other remedial actions to address the deterioration of frequency control under normal operating conditions.

> Delta Electricity recommends and encourages AEMO to maintain focus on other actions that improve frequency conditions. Adjustment to FCAS dispatch volumes made by AEMO in 2019 and early 2020 have demonstrably (see attachment 4) retarded the deterioration first identified in 2017 as being concerning to AEMO and lower demand conditions currently occurring appear also to be increasing the time frequency remains within the NOFB. Delta Electricity continues to believe that deterioration has much to do with factors, not related to PFR reduction, that are evidently influencing the day to day frequency performance.

5.1.2. AEMO's response

AEMO has a multi-pronged program of addressing the challenges faced by the lack of primary frequency response in the NEM and will continue to do so while implementing the PFR Rule, as all of its work will contribute to better control of power system frequency under normal operating conditions.

5.2. Implementation reporting

5.2.1. Issue summary and submissions

Although not raised during the forums, some submissions indicated that AEMO should collect and report on various PFR implementation data, impacts and learnings.

Alinta Energy submitted:

> Given this, Alinta Energy supports AEMO constructing both live and forecasting reports that should be presented as part of the PFRR obligation. Whilst this may not be possible due to privacy at the individual generator level, in aggregate it should be possible to provide broad data to industry on aggregate MW dead band settings, droop settings, response times and stored head room by regions. Such reports should also include both national and state current aggregated dead band or expected dead band data.
>
> The provision of such data would assist plant operators across the NEM in understanding the frequency performance of the market and how their individual generators will safely operate and perform within that. This will assist generators in performing their own stability analysis as well as completing the generator self-assessment.

Stanwell submitted:

> Stanwell strongly supports AEMO's proposal to implement the first tranche of generators through a managed transition process in order to minimise the risk of unexpected or unstable operation. Stanwell further suggests that this process represents the last reasonable opportunity to gather information on the relationship between the amount of plant enabled for PFR and the resultant effect on distribution of frequency – information that is likely to be required for the development of a long term market signal as envisaged by the AEMC.
>
> Having generating systems turn on PFR and narrow their dead bands progressively should provide a significant dataset, albeit one where enabled plant may not be providing PFR in all circumstances due to lack of headroom or foot room. Once generators are enabled for PFR under the current rules there appears to be no mechanism to reduce provision in order to investigate the impact on frequency control, however the Tasmanian trial and overseas experience points to tight frequency control being achievable without PFR provision from all generators.

CS Energy submitted:

> While CS Energy generally accepts the draft Interim PFRR, CS Energy remains of the opinion, as expressed in our submission on the Mandatory Primary Frequency Response Draft Determination, that the Interim PFRR does not appear to make provision for unforeseen outcomes and learnings arising from the early implementation of the proposed ±0.015Hz deadband for mandatory primary frequency response.

5.2.2. AEMO's response

AEMO agrees that careful management of implementation will be required, particularly for generation in Tranche 1. A staged approach to changes in deadbands is available to allay concerns over too drastic a change.

As noted in section 6.3.1 of the IPFRR, the process of implementing changes will require close coordination, and it is AEMO's intention to work with Affected Generators, both collectively and individually, to ensure any impacts on power system security and stability of plant are identified and managed.

AEMO agrees that implementation in stages will offer valuable insights into the effect of changing generation control settings on the power system overall, and on individual Affected GS. Any data generated throughout the process will be of value in considering what future changes could be required or be appropriate to the NEM's frequency control arrangements.

While AEMO will be able to collect some data at this time, for example, on power system frequency outcomes and system disturbances or similar events, some data from Affected Generators would also be required, for example, to identify the impacts of changing system frequency outcomes on plant operation and AEMO looks forward to Affected Generators' cooperation in sharing that data.

5.3. Timing for the submission of applications for exemption or variation

5.3.1. The issue

Questions were raised during the forums about whether the timing of the submission of applications for variation and exemption, specifically, what AEMO's actions would be if an Affected Generator had not submitted an application for either where the Self-Assessment clearly indicated that an application should be made.

5.3.2. AEMO's response

After further reflection on the matter, AEMO has determined that section 5.1(c) is not sufficient to alert Affected Generators that applications for exemption or variation should be submitted at the same time as the Self-Assessment results are submitted to AEMO. Sections 7.2 and 7.3 of the IPFRR have been amended to this effect.

5.4. Removing response time from PFRP

5.4.1. The issue

Some Consulted Persons considered that the response time should not be a PFRP and be relegated to an 'additional' performance requirement in section 4 of the IPFRR.

Delta Electricity submitted:

> It is recommended this parameter [section 3.4 response time] be moved to section 4 ….

ERM submitted:

> ERM Power notes and supports the inclusion of cross referencing to Section 4.2 with regards to the specification of "response time". However, we recommend that AEMO consider if the response time requirement set out in Section 3 would be better defined as an additional performance requirement in Section 4. This would result in the requirements around response time being specified in one section only of the PFRR.

CS Energy submitted:

> In the interests of consolidating the 'response time' requirements specified in section 3 and cross referenced to section 4.2, CS Energy suggests AEMO combines the response time, range of response and any other associated performance criteria into one section.

5.4.2. AEMO's response

AEMO acknowledges that the response time to a frequency change is a significantly more variable frequency response parameter PFRP than the deadband or droop. It is a characteristic that will vary widely between technologies, and even within a given plant over time, depending on operating conditions.

Ultimately, however, it is preferable to have some stated performance requirement in section 3 of the IPFRR, even if it was set at a relatively low level, than to have no requirement at all.

Many technologies and plant will easily meet this requirement under all conditions. If this is not possible, and the inability to meet this requirement is not due to one of the conditions specified in the standing variations in section 7.6, AEMO prefers that the Affected Generator apply for a variation.

5.5. Restructure of exemption and variation principles

5.5.1. The issue

Clause 4.4.2B(a) of the PFR Rule differs from the draft PFR Rule, in that it restructured the principles by which AEMO is to assess applications for exemption and variation and merged two principles.

5.5.2. AEMO's response

AEMO has restructured the sub-sections in section 7.1 of the IPFRR to mirror the structure of clause 4.4.2B(a) of the PFR Rule.

6. DETERMINATION

Having considered the matters raised in submissions and at the meetings and forums, AEMO's determination is to make the interim Primary Frequency Response Requirements in the form published with this Report, in accordance with clause 11.122.2(a) of the NER, with effect from 4 June 2020.

APPENDIX A. GLOSSARY

Term or acronym	Meaning
AEC	Australian Energy Council
Affected Generator	Any *Generator* registered to operate an Affected GS.
Affected GS	Any *scheduled generating system* or *semi-scheduled generating system*.
AGC	*automated generator control*
CEC	Clean Energy Council
Contingency FCAS	The following types of FCAS: • *fast raise service* • *fast lower service* • *slow raise service* • *slow lower service* • *delayed raise service* • *delayed lower service*
FCAS	*frequency* control *ancillary services*
FOS	*frequency operating standard*
IPFRR	The interim Primary Frequency Response Requirements developed and published by AEMO in accordance with clause 11.122.2(a).
MASS	*market ancillary service specification*
Maximum Operating Level	As defined in clause S5.2.5.11(a) of the NER.
Minimum Operating Level	As defined in clause S5.2.5.11(a) of the NER.
NEO	The national electricity objective, as that term is defined in section 7 of the *National Electricity Law*.
NER	National Electricity Rules
NOFB	*normal operating frequency band*
NSP	*Network Service Provider*
OEM	Original equipment manufacturer
PFCB	*primary frequency control band*
PFR	*primary frequency response*
PFR Rule	The National Electricity Amendment (Mandatory primary frequency response) Rule 2020 No. 5.
PFRR	*Primary Frequency Response Requirements*
Regulation FCAS	The following types of FCAS: • *regulating raise service* • *regulating lower service*
Self-Assessment	The self-assessment contemplated by section 5 of the IPFRR.

APPENDIX B. SUMMARY OF SUBMISSIONS AND AEMO RESPONSES

No.	Consulted Person	Issue	AEMO Response
1	Infigen Energy CS Energy Stanwell	Section 2 – Requirement to provide PFR See section 4.1.1.	See sections 4.1.2 and 4.1.3.
2	Stanwell	Specifically, where AEMO is attempting to correct accumulated time error it typically introduces a frequency bias to the calculation of AGC targets for units providing regulating FCAS. That is, if the system needs to “catch up” after a period of low frequency, AEMO set AGC targets to deliberately run the system fast (above 50Hz) and this is delivered by higher AGC targets for regulating raise providers and no response from other units. Individual units’ PFR droop response is typically calculated off a static 50Hz, meaning that with narrow dead bands mandated across the system, the higher AGC targets for the few regulating raise providers that are trying to physically run the system faster than 50Hz are likely to be offset by locally derived PFR droop signals from the many PFR enabled generators if frequency exceeds 50.015Hz. This would appear to limit AEMO’s ability to correct time error using regulation FCAS.	The likely effect of increased PFR around a narrowed deadband on NEM time error is unclear. Arguably, one reason for increased accumulation of NEM time error is due to the currently low levels of PFR, where the NEM is increasingly able to operate at up to 150 mHz away from the nominal 50 Hz, and thereby more rapidly accumulate time error. As the Stanwell submission correctly notes, the generation at tighter frequency deadbands will, all other things being equal, reduce the ability to run the power system ‘faster’ or ‘slower’ than the nominal 50 Hz to correct time error. The materiality of this issue, however, is unclear. It is also noted that the Frequency Operating Standard (FOS) has, over recent years, relaxed requirements in relation to the management of time error and is currently silent on the timeframes for correction of any time error that accumulates, so long as it can, ultimately, be corrected.
3	Alinta Energy	PFRR response when receiving >0 dispatch target As currently drafted in section 2 of the PFRR, the obligation applies to generators only when they have a dispatch target greater than zero (rules clause 4.4.2(c1)). However, if a generator receives dispatch targets across several intervals to meet a maximum dispatch target load, and mid-way through ramping up to meet such a target, simultaneously begins providing primary frequency response due to the PFRR obligation, how is the generator to be treated in relation to its obligations to follow dispatch targets? Alinta Energy seeks further clarification in section 2 of the PFRR in terms of how AEMO intends to	The relationship between clause 4.4.2(c1), 4.9.4 and 4.9.8 of the NER was canvassed extensively in AEMO’s rule change proposal and the AEMC’s consultation material for the PFR Rule, particularly the Final Determination. AEMO has amended section 2 of the IPFRR to clarify how Affected GS is expected to respond relative to non-zero dispatch instructions for different markets.

No.	Consulted Person	Issue	AEMO Response
		operationalise this requirement and the interaction between other NER obligations. In addition, if a generator is prevented from ramping up to maximum load as a result of providing PFRR response for a lengthy period of time (potentially hours) while responding to a frequency disturbance, how is it to be treated? It is unclear to Alinta Energy whether its normal bidding profile will be respected or whether a generator may be disproportionately required to provide PFRR response whilst commercial considerations are set aside. Alinta Energy encourages AEMO to provide some worked examples in the final PFRR document as a means to assisting participants understanding of how the PFRR will be operationalised.	
4	Delta Electricity	Section 3.2 – Maximum Allowable Deadband See section 4.11.1.	See section 4.11.2 and 4.11.3.
5	Delta Electricity Infigen Energy CS Energy ERM Power	Section 3.2 – Maximum Allowable Deadband See section 4.2.1.	See section 4.2.2 and 4.2.3.
6	ERM Power	Section 3 – Primary frequency response parameters We also note that the Final Determination of the Mandatory primary frequency response rule change determined that; "As part of meeting the requirements of the PFRR, generators will be required to provide a frequency response to a deadband no narrower than the primary frequency control band. However, other response characteristics such as droop and response time will only be specified by AEMO as part of the requirements if practical to do so." As the amended rule requires AEMO to develop and publish the interim PFRR in consultation with Market participants, it is our view that the amended rules intended that the requirements for characteristics such as droop and response time would form part of the consultation process for the development of the PFRR, as opposed to characteristics already set by AEMO prior to consultation commencing. We believe that in considering these characteristics as part of the consultation process AEMO should set out why the values proposed by AEMO for these additional	The point is moot. The proposed parameters have been public for some time. The justification for these parameters was submitted with AEMO's rule change proposal and the subject of the AEMC's consultation on the PFR Rule.

No.	Consulted Person	Issue	AEMO Response
		characteristics are technically required to meet the PFRR with regards to operation of the power system.	
7	Edify Energy CEC Tilt Renewables Origin Energy AGL Energy	Section 3.3 – Droop See section 4.5.1.	See sections 4.5.2 and 4.5.3.
8	Delta Electricity	Section 3.3 - Droop For Units with complex governing systems involving several controllers operating together, coordinated sub-systems can deliver an overall droop <= 5% with one subsystem >5%. The reaction from a mechanical governor delivers throttle valve positional change adjusting turbine load position proportional to a detected speed change. Its feedback is based on positional change not on delivered MWs. At nominal steam conditions for the dispatched load, the MWs delivered by a reaction to turbine speed change will be that expected from the droop lever ratio of ~4%. If actual steam conditions are less than nominal, the delivered MWs will be less than expected. If the initial stable speed from which the response is detected and/or the final stable speed where the response ceases are not 3000rpm, the turbine mechanical-hydraulic governor could be responding at odds with overall required corrections. A better droop equation for the mechanical-hydraulic governor is below: $\boldsymbol{Droop}\ (\%) = \mathbf{100} \times \Delta\mathbf{S/S0}\Delta\mathbf{TV}/\boldsymbol{TVMAX}$ Where: ΔS = change in turbine speed detected, in rpm. S0 = initial stable speed that may not be 3000rpm ΔTV = change in throttle valve position TV_{MAX}= maximum throttle valve movement The reaction from the DCS FCAS controller is added or subtracted to the dispatch target which in automatic dispatch from AEMOs AGC may well result in different overall outcomes for steady loading to that of energy ramp increases and decreases. The direction of a required PFR frequency response relative to an	AEMO understands that the overall response of an Affected GS can change, depending on whether it has a steady dispatch target, or whether it is ramping to a new dispatch target, either up or down. The IPFRR has been updated to detail the expected outcomes when, for example, an AGC ramp may be moving an Affected GS in one direction, and a response to frequency may try and move it in the opposite direction. The PFRR specifies a high-level overall objective for the response at the connection point. It does not aim to specify the exact control arrangements within the Affected GS that are used to meet this overall objective or requirement.

No.	Consulted Person	Issue	AEMO Response
		energy ramp direction is important to consider and it is recommended AEMO focus on droop reactions under steady load dispatch conditions.	
9	CS Energy	Droop CS Energy notes the absence of any reference to a fixed droop (no deadband) governor setting in the Rules or in the AEMO Interim PFRR consultation. CS Energy also notes that recently during NEM systems failure, AEMO has required nominated Registered Participants to provide frequency control using their generating system(s) with this fixed droop characteristic. If the nominated generating system(s) can provide frequency control and utilising this fixed droop characteristic, this potential outcome would conflict with the Rule and the AEMO Interim PFRR document specifications as currently written.	There is no conflict between the PFR Rule and the IPFRR. The responses provided in the incidents described were consistent with those proposed under the PFR Rule, and the IPFRR.
10	Delta Electricity	Section 3.4 – Response Time For Units with complex coordinated governing reactions from a variety of controllers, planned testing of a machine's complete response in a controlled manner is very difficult. The mechanical governor rotating element is driven off the turbine shaft and is not testable by introducing a simulated precision step change to its rotational speed. In the DCS, a simulated test on the FCAS controller can occur but the result won't include the natural response from the mechanical governor which will actually act in opposition to the DCS simulated speed response. Delta Electricity believes the capability required by the draft PFRR cannot be guaranteed to be consistently delivered by systems such as at Vales Point. Apart from the different systems of governing that operate, the operational circumstances that affect steam conditions are many and varied. A response of the type defined may occur where nominal fuel quality, full operating capacity and typical ambient conditions apply but variations will still occur regularly that will result in under delivery. The determination of adequate damping is also fundamentally difficult to examine and determine when the Unit is coupled to many other systems and controllers. How does AEMO expect each assessment of adequate damping to be performed? Does AEMO have standard spreadsheets that perform adequate damping arithmetic to aid participants in assessing responses? It is recommended AEMO consider a simpler definition easily	See response to item 8 in this table. On the specification of adequate damping, AEMO refers to the definition in the NER, which is used in existing publications, such as the Power System Stability Guidelines, and the NER on this standard control system requirement. Creating a new term to address this general requirement for the purposes of the PFR Rule is not considered prudent and would not improve implementation of the PFR Rule.

No.	Consulted Person	Issue	AEMO Response
		comparable on a presented trend or provide the method for participants to compare damping is adequate to the full Rules definition. … It is recommended … that adequate damping be replaced by a simpler expression of halving time of oscillatory amplitudes.	
11	Stanwell	Clause 3.4 – Response Time Typically, under droop action, active power response is proportional to frequency deviation, and consequently the time taken to achieve a 5 per cent change in output will depend on the size of the stimulus applied. A future response may not achieve a 5 per cent change in active power in 10 seconds as required under the clause if the stimulus is small or gradual. Stanwell is concerned that this may result in technical non-compliance with the PFRR. Stanwell suggests that either there is an acknowledgement in the PFRR that active power response is proportional to frequency deviation, or that the step size be stipulated as 0.5Hz.	The response time requirement is specified with respect to a notional step change in frequency. Such a disturbance will represent the ultimate underlying response capability of an Affected GS. In real events, however, frequency will change at a more gradual rate, and it is understood that as a result, the Affected GS's response will also be more gradual. Such an outcome would not be considered as a non-compliance with the PFRR.
12	Hydro Tasmania	**Response Time implication (Section 3.4)** Hydro Tasmania considers that the response performance stated in S3.4 should only represent the machine response performance under the given operating conditions at that point in time. Therefore, the data from these trials, for the purpose of PFR verification, should not be used as, or considered to be, a reference for potential future compliance assessments, which may be under very different operating conditions.	Where an Affected GS is consistently unable to achieve the specified response time requirement, the Affected Generator may seek a variation and provide suitable technical evidence. Where the inability is based on one of the standing variations specified in section 7.6, and applies for a limited timed only, no variation would be required.
13	Hydro Tasmania	**Response active power definition (Section 3.4)** Hydro Tasmania seeks to confirm that the '5% change of Pmax' in section 3.4 refers to primary electrical power injection only and that the inertial response is excluded. Hydro Tasmania would also request confirmation that the Pmax definition refers to the rated power of the individual machine, so that an individual unit is not assessed against the aggregated output of the dispatchable unit (DUID) of which the individual machine is a part of.	Inertial response would be excluded from any actual measured response. P_{MAX} is defined for a generating system, which is normally applied at a DUID level.
14	Vestas	On Section "3.4 Response Time", the "5% change in active power output, within no more than 10 seconds". Please clarify if the required active power ramp rate is at least 0.005pu /sec.	A 5% change in active power in 10 seconds would require an active power ramp rate is at least 0.005pu/s, however, if plant can safely and stably ramp at a higher rate than this, it

No.	Consulted Person	Issue	AEMO Response
			should do so, and not reduce its ramp rate to this minimum specified level as a requirement of the PFR Rule.
15	Delta Electricity ERM Power	Removing response time from PFRP See section 5.4.1.	See section 5.4.2.
16	CS Energy	Other response characteristics CS Energy notes the Final Determination of the Mandatory primary frequency response Rule change specified that: "As part of meeting the requirements of the PFRR, generators will be required to provide a frequency response to a deadband no narrower than the primary frequency control band. However, other response characteristics such as droop and response time will only be specified by AEMO as part of the requirements if practical to do so." AEMO has set out several other response characteristics in the Interim PFRR document. As specified in the final Rule, AEMO is required to develop and publish the Interim PFRR document in consultation with Participants. CS Energy considers AEMO should have provided an indicative framework of response characteristics and noted that through further consultation AEMO would determine and specify the final other response characteristics to deliver the PFRR. CS Energy agrees that response time is technology specific as inferred by AEMO in the Interim PFRR document. This further reinforces the CS Energy position that the final other response requirements should be captured in the AEMO consultation rather than having the characteristics determined by AEMO prior to the commencement of the consultation. The consultation process will enable AEMO to justify the parameters and characteristics for the proposed other response requirements. Further examples of parameters linked to the other response characteristics that need to be considered include but are not limited to: (a) Rule s 5.2.5.11 Frequency control may have no reference to the PFRR parameter(s) as applicable to a Registered Participants Affected GS(s) GPS or conversely has a reference that conflicts with the specifications in the Interim PFRR document that will require resolution of the conflict;	The abridged consultation for the IPFRR precluded the extensive formal consultation suggested by CS Energy, but AEMO has been consulting with Affected Generators informally for some time. In response to the numbered items: (a) See section Error! Reference source not found.. (b) This is covered by the standing variations in the new section 7.6 of the IPFRR. (c) See section Error! Reference source not found.. AEMO intends for the GPS to be consistent with the IPFRR. (d) See section 4.6.

No.	Consulted Person	Issue	AEMO Response
		(b) Affected GS(s) experiencing short term stability issues may result in a control system switch to 'desensitised mode' providing 50% of normal gain; (c) PMAX Maximum Operating Level is referenced to Rule s 5.2.5.11 (a) and combined with no requirement for the provision of 'headroom' and any potential conflict with the provisions in the Registered Participants Affected GS(s) GPS, AEMO will need to specify 'PMAX' in the context of the Interim PFRR. CS Energy understands that AEMO intends to allow the Registered Participant to nominate the PMAX for each of the Participants Affected GS(s) in their portfolio; and (d) CS Energy considers factors such as overload operation, impact of coal (fuel) quality, mills in service need to be taken in consideration in the finalisation of the other response characteristics as applicable to individual Affected GS(s).	
17	ERM Power CS Energy	Section 4 – additional performance requirements See section 4.8.1.	See sections 4.8.2 and 4.8.3.
18	Delta Electricity	Section 4.1 - No Withdrawal of Response Mechanical governors respond to speed change and will cease responding when speed is settled, even if it isn't 3000rpm. The mechanical governor deadband is relative to the speed from which the governor first reacts.[5] The response is not withdrawn but ceases when the required throttle valve movement, representing the required MW change for the detected speed change, is complete, at which point the mechanical feedback shuts off the hydraulic energy source to the throttle valves actuators. Unit MW controllers observe AEMOs AGC targets and also any error resulting from mechanical governing reaction. MW controllers eventually need to perform corrections to dispatch to achieve dispatch objectives to balance Generation and Demand outcomes. This correction back to energy dispatch objectives can appear as a withdrawal of the PFR. The withdrawal can be prevented by tighter deadbands on the DCS Frequency Controller. The DCS FCAS controller operating on a tighter deadband can provide a sustain a MW response from the mechanical governor and hold the turbine to that requirement for short periods and only	The underlying limitations of plant to provide sustained response are acknowledged in the IPFRR. In particular, the standing variations in section 7.6 should cover the requirements detailed in the submission. Contingency Raise FCAS will continue to be dispatched and paid in accordance with the FCAS market design.

[5] These first two sentences can also be found in Delta Electricity's response to section 3.2.

No.	Consulted Person	Issue	AEMO Response
		within the limits of available prepared energy to do so for raise response, or above Unit instability conditions for lower responses. Sustained system conditions cannot be permanently catered for by such machines except by way of adjusted energy dispatch from AEMOs AGC, energy rebidding or Unit automatic removal if instability is too great. Adequate balanced dispatch conditions eventually have to be prepared for via AEMO AGC allowing time for recovery in the Unit conditions.	
19	Delta Electricity	Section 4.2 - Range of Response See section 4.8.1.	See sections 4.8.2 and 4.8.3.
20	Delta Electricity	Section 4.3 - Continuity of Response See section 4.6.1.	See sections 4.6.2 and 4.6.3.
21	Vestas	• Please clarify if spinning reserve becomes a requirement for semi-scheduled generators as this requirement is implied by the Continuity of Response requirement. … • The recommended maximum droop amendment of 5%, requires minimum of 40% of $PPmmmmmm$ response for 1 $HHHH$ frequency deviation instead of minimum of 20% of $PPmmmmmm$ response for 1 $HHHH$ frequency deviation according to the requirements of the Automatic access standard. Therefore, the proposed PFRR doubles the spinning reserve with the maximum allowed droop gain changed from 10% to 5%. • It may not be economically feasible for renewable generation to operate curtailed to provide large spinning reserve in order to fulfil underfrequency response requirement. It seems to Vestas that the recommended mandatory PFRR serves as a technical push to energy storage in the renewable energy industry.	The PFR Rule does not require any headroom, 'foot-room', 'spinning reserve' or energy storage.
22	Vestas	Please clarify if synthetic inertia from wind turbine generators becomes a requirement for under-frequency control. If synthetic inertia is an option, please clarify what is the expected performance during the over-boost period and the recovery period	The PFR Rule does not create a requirement for any form of synthetic inertia or similar control response from generation.

No.	Consulted Person	Issue	AEMO Response
23	Hydro Tasmania	**Due dates for Affected Generator self-assessments** Hydro Tasmania is seeking AEMO's confirmation that the time frame specified in Table 2 is based on individual machine nameplate ratings rather than the DUID rating (e.g. individual Gordon units (144MW) will be considered in the second tranche).	The results of Self-Assessments are specified on a generating system basis, which is typically at the DUID level.
24	ERM Power	Section 5 – Initiation of Application With regards to the requirement to specify a date to achieve a deadband of +/- 0.015 Hz and noting our request to amend Section 3 with regards to the required deadband setting, we offer the following amendment to 5.1 (b); nominate using the form in [Appendix A] whether it wishes to alter the Affected GS' Deadband to ~~±0.015Hz~~ the final deadband setting agreed between AEMO and the Market Participant for the Affected GS.in one step, or to ±0.05Hz, or another interim deadband setting agreed between AEMO and the Market Participant for the Affected GS. and then to ~~±0.015Hz~~ the final deadband setting agreed between AEMO and the Market Participant for the Affected GS.on another date, to be co-ordinated by AEMO; and	ERM suggests interim and final deadband settings should be negotiable. For reasons explored extensively during consultation on the PFR Rule, the final deadband needs to be a consistent value across all capable scheduled and semi-scheduled generation, at ±0.015Hz. An interim setting of ±0.05Hz was suggested by Consulted Persons during the forums because it is a known setting with which Affected GS in New South Wales have operated in the past. AEMO has agreed to adopt this as part of a managed transition towards a tighter setting. See section 4.1 and 4.11.
25	Delta Electricity	Section 5.1(b) - Initiation of Application – Existing Affected Generators The deadbands values need to be amended to include for the very likely possibility that variations will be adopted. It may also need rewording to allow for plant that is proven to have an unadjustable zero deadband.	Noted.
26	Delta Electricity	Section 6.1 – Insufficient Information & Section 7.1.1 – Exemptions and Variations - Capability The clause should refer to the extension of time clause. It is possible the information doesn't exist or cannot be supplied by an OEM in which case how should AEMO and the participant approach settings that may lie outside available operating experience and knowledge, have no previous test results and where no OEM advice is available? How will the potential risk of damage be mitigated and will be the burden of risk be carried by AEMO and the participant compensated if there is temporary or permanent damage impacted on a Unit?	The grant of an extension of time is already addressed in section 6.2 of the IPFRR. If no information exists or can reasonably be found to substantiate a matter required to be substantiated as part of the Self-Assessment, the Generator will need to apply for an exemption or variation, as applicable. This risk identified in the submission is must be identified by the Generator and communicated to AEMO, who will then work with the Generator to identify appropriate mitigations.

No.	Consulted Person	Issue	AEMO Response
		Older plants sometimes have no information. The age of components also warrants caution in application of more sensitive controls in case of substantial damage resulting from an insistence of application if a participant's self-assessment, variation or exemption application carries no available evidence and AEMO chooses to reject full exemption or variations applications.	AEMO notes that the provision of PFR is subject to plant safety, which is now specified as a standing variation from the requirement for the provision of PFR.
27	Delta Electricity	Section 6.3 – AEMO Response Some paragraphs in this section are more descriptions about AEMOs response to submitted self-assessment results. See comments above on the overall process. Paragraphs 2 and 3 are not really obligations and could be removed to a more general section or appendix describing the overall process and providing examples.	Noted.
28	CS Energy	CS Energy notes that in section 6.3.1, the reference to Appendix B should be Appendix C.	Noted.
29	ERM Power CS Energy Infigen Energy AGL Energy	Section 7 – exemptions and variations See section 4.7.1.	See section 4.7.2 and 4.7.3.
30	Stanwell	7.1.1 - Capability This clause currently requires that "the Affected Generator must provide evidence of test results or other technical information, including evidence from the OEM, to demonstrate the unstable operation." … This issue could be addressed by allowing the assessment to be conducted by a consulting engineering firm as alternative to the OEM, an amendment we understand AEMO are already considering.	Agreed.
31	Origin Energy	Section 7.3 Variations should consider the shape of response from generator Origin welcome's AEMO's flexibility in providing variations where generators may not be able to meet the specifications laid out by the PFRR. The current drafting of section 7.3 implies that	Appendix A of the IPFRR has been updated to indicate the information to be provided to assist AEMO's assessment as have the applications in Appendix D, for exemptions, and Appendix E, for variations.

No.	Consulted Person	Issue	AEMO Response
		variations are available but doesn't make clear what generators can request as part of their self-assessment. We suggest that section 7.3 directly specify that variations are available for generator's droop, deadband, along with the speed, range and continuity of response. We also suggest that the PFRR specify that variations will be available for generators that respond in a nonlinear manner. Some generators can respond in a way that meets the PFRR obligations under most conditions but not do so under other circumstances. For example, some generators may not be able to respond (in either direction) while at their maximum output, but could otherwise satisfy the PFRR. The PFRR and the self-assessments templates should allow for generators to indicate where they would require variations, even when these variations are not always needed by that generator.	A range of typical or expected conditions are consolidated in section 7.6 as standing variations, which address the points raised in this submission.
32	Delta Electricity	Section 7.4.1 – Insufficient Information The clause should refer to the extension of time clause.	Agreed.
33	Delta Electricity	Section 7.5 – Standing Exemptions Include for standing variations.	Noted.
34	Delta Electricity	Section 8.1 & 8.2 – Stability Tests - General Some plant can perform step tests on a sub-system of the overall PFR system.	Noted.
35	Forums	Several Consulted Persons were concerned about the lack of guidance on when was the optimal time/date for the testing of Affected GS.	A test is not required for an Affected Generator to complete a Self-Assessment. It is within an Affected Generator's discretion as to whether they need to carry out a test to raise confidence in the results of their Self-Assessment. AEMO has amended Appendix A to include questions about testing so that Affected Generators can include this matter for discussion with AEMO at the appropriate time.
36	ERM Power	Section 8 – Stability Tests In order to eliminate the possibility of misinterpretation from the second paragraph of subsection 8.1, we recommend re-ordering of the initial words of the paragraph to make it read: "Where material changes are only made to governor or plant load controller deadbands, or to the DCS, modelling and	The second paragraph of section 8.1 has been amended for clarity. AEMO has no intention of seeking an enhancement to current monitoring capabilities by Affected Generators as a result of the PFR Rule.

No.	Consulted Person	Issue	AEMO Response
		testing beyond that described in section 8.2 will not be required by AEMO until expiry of the testing cycle detailed in an Affected GS' compliance program under clause 4.15(b) of the NER. We also note AEMO's inclusion of recorded test outcomes of "Values are to be provided to AEMO at a sample rate of no less than one sample per cycle, unless agreed by AEMO" We note that the Final Determination for the Mandatory primary frequency response rule change and final rule had both the intent and clearly stipulated that AEMO may not require either the installation of new or the modification of monitoring equipment to monitor and record the response of the relevant generating system to changes in power system frequency. "In response to stakeholder concerns made on the draft rule, the final rule also provides that the PFRR must not require the installation or modification of monitoring equipment to monitor and record the response of the relevant generating system to changes in power system frequency for the purpose of verifying compliance with the mandatory PFR requirement. The final rule does require, including consulting with industry, AEMO to document the details of the information to be provided by Generators to verify compliance with the PFRR, including any compliance tests or audits and testing requirements for the purpose of verifying compliance through its PFRR." [14] We are concerned that the inclusion of words "Values are to be provided to AEMO at a sample rate of no less than one sample per cycle, unless agreed by AEMO" in the interim PFRR seeks to circumvent this area of the final rule change and recommend that the wording be changed to; Values are to be provided to AEMO at a sample rate agreed between AEMO and the registered Market Participant for the Affected GS based on the capability of existing monitoring equipment in accordance with the requirements of NER subclause 4.4.2A (c)." This ensures that an agreement must be reached following consultation to the satisfaction of both AEMO and the Market Participant rather than just AEMO.	Requiring an agreement between AEMO and Affected Generators without any reference to current capability as a starting point could lead to unnecessary implementation delays. Monitoring and data recording requirements have been updated to allow for altered requirements by agreement.

No.	Consulted Person	Issue	AEMO Response
37	CS Energy	Section 8 - Stability Tests In the absence of AEMO's justification for a frequency step response stability test, CS Energy views the proposed requirement for the test as a duplication of tests already conducted by the Affected GS(s) for its GPS. A change to the deadband setting does not affect the governor response for a frequency deviation outside the deadband. Participants will have already submitted models and data as required for GPS R1 and R2 tests and will have demonstrated both stability and capability to reduce load more than 5% in 10 seconds. The current requirement for a frequency step response stability test does not appear to be justified and will impose unnecessary costs on Participants. Section 8.2.2 of the draft Interim PFRR provides: "Values are to be provided to AEMO at a sample rate of no less than one sample per cycle, unless agreed by AEMO that a different rate is acceptable." CS Energy would like AEMO to clarify in the final version of the Interim PFRR that the parties must consult to reach the agreement if a different rate is proposed.	AEMO has included a new section 8.2.3 to indicate that which alternatives to tests are acceptable. Section 8.2.2 indicates that Affected Generators may nominate alternatives, and AEMO must then indicate which, if any, alternative rate is acceptable. No further clarification is considered necessary.
38	Stanwell	Clause 8.1 Stability Tests – General Stanwell would like clarification as to whether R2 model validation testing would be required if changes to response limiters are considered material in the context of this clause. If this is the case, Stanwell considers this is an unnecessarily onerous testing requirement due to the expensive and involved R2 processes. Stanwell suggests that the clause be amended to specifically exclude limiter changes along with dead bands. Stanwell also suggests that the clause (or 6.3.2) be made clearer to remove any confusion that post implementation testing at the PFRP as approved under 6.3.2 is required.	Response or load limiters have been added to the list of alterations that would not trigger R2 type modelling requirements.
39	AGL Energy	Section 8.1 Section 8.1 states that "Any change to a control system or primary plant will require at a minimum a step response stability test as specified in section [8.2] or where a step test might not be possible, an alternative test to demonstrate stability following changes to meet the PFRR." In our view, this wording should be amended to clearly state that it applies to changes to control systems or primary	The provision has been amended. AEMO acknowledges that the term 'material changes' is subjective, however, the range of all possible changes is very wide, and it is not possible to draw a clear line on what would be material. The details will only be known once the Self-Assessments are completed.

No.	Consulted Person	Issue	AEMO Response
		plant with respect to frequency control, so as to remain in scope of the final rule and not attempt to capture additional matters. Section 8.1 refers to 'material changes' to DCS, or to governor or plant load controller deadbands, and beyond. The concept of 'material changes' is highly subjective in the absence of detailed guidance. We consider this section requires further explanation from AEMO and may even benefit from practical examples of material versus immaterial changes, to guide generators on how AEMO will determine which category changes will fall into, and the subsequent level of testing required. Section 8.2 of the PFRR provides that stability can be demonstrated through a step response stability test or actual response to a power system disturbance. The final rule provides that the procedure to alter a generating system in clause 5.3.9 of the NER does not apply to modifications made by a generator in order to comply with the PFR requirements applicable to that generator.	The suggestion that the IPFRR could apply to matters unrelated to the PFR Rule is unsustainable. No changes are required to address the point made in the first paragraph. The third paragraph is noted.
40	Hydro Tasmania	Stability Tests (Section 8) Where testing is undertaken, Hydro Tasmania seeks AEMO's confirmation that the machine stability demonstration, after revising the governor deadband to ±0.015Hz, can be integrated with the Response Time test specified in S 3.4. This means that the recording interval in S 3.4 would be extended to at least 10 seconds pre-triggered recording and at least 60 seconds recording after the unit has settled at its steady-state value.	AEMO agrees that these tests could be combined.
41	Delta Electricity	Section 8.2.1 – Stability Tests – Step response Stability Test AEMO may wish to consider including wording that permits short periods of notice with AEMO agreement because it is considered possible that strict adherence to 10 business days may not always suit AEMO, the TNSP and the participant acting reasonably. The determination of adequate damping is fundamentally difficult to examine and determine when the Unit is coupled to many other systems and controllers. How does AEMO expect each assessment of adequate damping to be performed? Does AEMO have standard spreadsheets that perform adequate damping arithmetic to aid participants in assessing responses? It is recommended AEMO consider a simpler definition easily comparable on a presented trend or provide the method for participants to compare damping is adequate to the full Rules definition.	AEMO has updated section 8.2.1 to allow for a shorter period by agreement. On the issue of adequate damping see item 10 of this table. Use of alternative measurement arrangements, including those of used by an NSP, where available, has been included.

No.	Consulted Person	Issue	AEMO Response
		Response time confirmations only need to be performed for either a positive or negative active power change. The recording system will be whatever is already installed as the Rule does not require the installation of new recording equipment with the ability to measure to one sample per cycle. TNSP records may be accessible.	
42	Delta Electricity	Section 8.2.2 – Stability Tests – Actual Response to Power System Disturbance Some plant can perform step tests on sub-systems of the overall PFR system but an actual response to power system disturbance would be required to demonstrate the coordinated response from the overall system. The recording system will be whatever is already installed as the Rule does not require the installation of new recording equipment with the ability to measure to one sample per cycle. TNSP records may be accessible.	Noted.
43	ERM Power	Section 9 – compliance See section 4.6.1.	See sections 4.6.2 and 4.6.3.
44	CS Energy	AEMO have advised that they will initially not be monitoring the Affected GS(s) PFR status. CS Energy strongly encourages AEMO to monitor Affected GS(s) PFR status to provide the visibility when the PFR is enabled or disabled during the intermittent periods of PFR unavailability.	Noted, however, AEMO is unable to engage in the type of monitoring suggested with existing monitoring equipment. Moreover, it would be unusual by international standards.
45	Delta Electricity	Section 9.1 – Compliance – Ability to Operate in Frequency Response Mode and Sustain PFR Mechanical governors respond to speed change and will cease responding when speed is settled, even if it isn't 3000rpm. The mechanical governor deadband is relative to the speed from which the governor first reacts. The response is not withdrawn but ceases when the required throttle valve movement, representing the required MW change for the detected speed change, is complete, at which point the mechanical feedback shuts off the hydraulic energy source to the throttle valves actuators. Stabilised frequency at any value will cause the mechanical response to cease but DCS FCAS response will continue if frequency remains outside the deadband of the FCAS controller.	See section 4.6.2 and 4.6.3.

No.	Consulted Person	Issue	AEMO Response
		However, in a sustained frequency event that runs across Dispatch intervals, AEMOs AGC and its dispatch decisions will influence the outcome of the DCS FCAS controller setpoint on Units remotely controlled by AEMO. Unless AEMO is intending to install additional controllers to influence and override NEMDE and AGC dispatch outcomes, this situation may need including for in Standard variations and in clause 9.1.	
46	Stanwell	Clause 9.1 Compliance - Ability to Operate in Frequency Response Mode and Sustain PFR As discussed in our commentary on clause 4.3 above, there are several known conditions that should be accommodated in addition to those already referenced in 9.1. Stanwell suggests that a reference be added to clause 9.1 to capture the standing exemptions, which we proposed to be added as clause 7.6 above.	Noted, but unnecessary in light of new section 7.6 dealing with standing variations.
47	Delta Electricity	Section 9.2 – Changes to PFR settings See section 4.6.1.	See sections 4.6.2 and 4.6.3.
48	Delta Electricity	Section 10(c) – Publication of Primary Frequency Response Outcomes – (c) variations See section 4.14.1.	See section 4.14.2 and 4.14.3.
49	Alinta Energy	Transparency of aggregate PFRR performance The provision of frequency control involves costs on plant and general wear and tear. The provision of these services deteriorates the operating life of units and requires an additional level of maintenance costs. For example, in regards to a gas fired generator, since the load gradient in frequency response mode is higher than during normal operation the thermal stress on the gas turbine is also higher. Therefore, operating hours beyond the frequency deadband are weighed with a factor greater than 1 in order to calculate the equivalent operating hours. This will reduce the interval time between regular inspections which are due after a given amount of equivalent operating hours defined by the original equipment manufacturer have passed. These costs vary greatly depending on the dead band frequency ultimately set as well as the order in which individual generators tighten their dead band settings.	AEMO intends to work closely with Affected Generators to coordinate implementation of the PFR Rule, particularly for those whose Affected GS are in Tranche 1. Close coordination of deadband changes is necessary to help avoid or minimise first mover disadvantage.

No.	Consulted Person	Issue	AEMO Response
		Alinta Energy is concerned that first movers could face significant disadvantages as the PFRR is rolled out across the NEM. As generators over 200MW adhere to the PFRR requirement, this exposes the first enabled units to a greater share of the frequency burden such as oscillatory interactions between different governors or hunting oscillations. The same is true for the first individual generators in certain regions or states whom are enabled. Thus, there is a high likelihood that the burden of costs will shift to predominantly to larger dispatchable technologies. This not only has equity implications; it also has implications for the generator self-assessment process. The internal risk assessments and generator self-assessment process currently being considered by participants are being made on the assumption that there is a "hard cutover" time where all generators over 200MW are tightening their dead bands. If generators are switching to the new PFRR requirement at different times, or even at different dead band settings, this will have direct implications for the performance of individual units and the generator self-assessment results.	
50	Alinta Energy	Progressive Reduction in Dead band Setting See section 4.11.1.	See section 4.11.2 and 4.11.3.
51	Alinta Energy	Frequency Signal Conditioning – further clarifications required Alinta Energy is seeking more clarification or guidance respectively with regards to the requirements for filtering (e.g. low pass filtering) and conditioning of the frequency signal measured at the connection point. The intention is to avoid any unnecessary load cycles - which are detrimental to the gas turbine's service life - that may be caused by the frequency crossing the limit of the deadband for a fraction of a second only or noise superimposed to the frequency signal. These are load cycles that would not contribute to grid stability but adversely affect the performance of the gas turbine.	It does not appear to AEMO that the IPFRR is an appropriate instrument to describe such specific control and measurement requirements.
52	Stanwell	Appendix A Section 3 – Results of Self-Assessment It is currently not clear if self-assessment is intended to capture existing capabilities, settings and configurations or what is predicted that the plant will achieve in the future if it is modified to deliver PFRR as much as physically possible. A misinterpretation of this requirement could result in incorrect information being supplied to AEMO as part of the self-assessment.	Changes made to Appendix A have addressed this concern.

No.	Consulted Person	Issue	AEMO Response
		Stanwell is seeking clarification on what information AEMO is seeking in this section (in the context of subsequent sections) and suggests that the wording be amended so there is no confusion on the part of generators as to what is to be provided.	
53	Delta Electricity Origin Energy Infigen Energy	Timelines See section 4.12.1.	See section 4.12.2 and 4.12.3.