RULE

Australian Energy Market Commission

DIRECTIONS PAPER

FREQUENCY CONTROL RULE CHANGES

PROPONENTS

AEMO
Infigen

17 DECEMBER 2020

INQUIRIES

Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

E aemc@aemc.gov.au
T (02) 8296 7800

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

EXECUTIVE SUMMARY

1 The Commission is seeking stakeholder feedback on two rule change requests related to the control of power system frequency to help 'keep the lights on'.

2 This paper discusses the market and regulatory arrangements that support the control of power system frequency. Frequency control services are a subset of the ESB's essential system services market design initiative. The paper sets out initial views and high-level policy directions on key issues arising from each of the frequency control rule changes that relate to the arrangements for fast frequency response and primary frequency response in the NEM. The paper identifies key decision points and areas where further investigation and technical input from AEMO will be used to support the Commission's draft determination.

3 To keep the lights on, the power system needs to be:

- **secure** – that is, able to operate within defined technical limits, even if there is an incident such as the loss of a major transmission line or large generator.
- **reliable** – that is, with enough generation, demand-side and network capacity to supply customers with the energy that they demand with a very high degree of confidence.

4 In order to maintain the power system in a secure operating state and avoid unplanned system outages, power system frequency must be controlled within a narrow range around 50Hz. This is achieved by dynamically balancing electricity generation and consumption in real time.

5 In practice, the control of power system frequency requires a sufficient quantity of inertia and frequency responsive reserves that are available to respond to correct deviations away from 50Hz. Inertia acts to resist changes in frequency due to sudden changes in supply and demand. It is provided inherently by large spinning machinery associated with synchronous generators such as coal, hydro and gas-fired power stations. Frequency responsive reserves are provided by a range of technologies, including generation, storage and demand response who are enabled through the market arrangements for frequency control ancillary services (FCAS) that operate alongside the market for energy in the National Electricity Market (NEM).

6 The two rule change requests discussed in this paper are:

- **Infigen Energy — *Fast frequency response market ancillary service*** — This rule change proposes the introduction of spot-market arrangements for Fast frequency response (FFR) to help efficiently manage system frequency following contingency events during low inertia operation.
- **AEMO — *Primary frequency response incentive arrangements*** — This rule change request proposes changes to the NER to support improved frequency control during normal operation.

7 These rule changes are referred to in this paper as the Frequency control rule changes.

8 The ESB, AEMC, AEMO and AER have undertaken a substantial amount of work over recent years in relation to the frequency control frameworks in the NEM. The Commission's assessment of the frequency control rule changes is consistent with and builds on this work.

9 In March 2020, the AEMC introduced an obligation for all scheduled and semi-scheduled generators in the NEM to support the secure operation of the power system by responding automatically to small changes in power system frequency. In its final determination, the Commission noted that a mandatory requirement for PFR on its own is not a complete solution and that further work needed to be done to understand the power system requirements for maintaining good frequency control. The Commission noted that it would be preferable to introduce alternative or complementary arrangements that incentivise and reward the provision of PFR. As a result, the Commission determined that the Mandatory PFR rule would be an interim arrangement which would sunset on 4 June 2023.

10 AEMO is currently in the process of coordinating changes to generator control systems in accordance with the Mandatory primary frequency response rule. The monitoring of plant and power system impacts due to the roll out of the Mandatory PFR requirement will help inform the Commission's determination of the enduring PFR arrangements.

11 Through the *Frequency control frameworks review*, the Commission also examined the broader structure of the existing FCAS markets to determine whether they will remain fit for purpose in the longer term as the power system changes, how to most appropriately incorporate fast frequency response, or enhance incentives for fast frequency response within the existing markets, and longer-term options to facilitate co-optimisation of energy, FCAS and inertia. Findings from this review will be an important input into any new arrangements for the provision of faster responding services.

12 Interaction with the Energy Security Board's post 2025 market design project

13 In March 2019, the COAG Energy Council requested the Energy Security Board (ESB) to advise on a long-term, fit-for-purpose market framework to support reliability, modifying the NEM as necessary to meet the needs of future diverse sources of non-dispatchable generation and flexible resources, including demand side response, storage and distributed energy resource participation. A key part of this work is the ESB's thinking on essential system services and scheduling and ahead mechanisms.

14 The AEMC is working closely with the ESB and the other market bodies, particularly AEMO, on these rule change requests given that these rule change requests dovetail with the direction of this other work. The rule change requests and so this paper complement and are interdependent with the work of the ESB in its 2025 project. These rule changes provide us with an opportunity to complement some of the thinking and assessment done in the ESB work program, as well as technical input from AEMO through its Renewable Integration Study.

15 Submissions to this paper will be used by the 2025 project to inform its analysis. In progressing these rule changes, the AEMC will consider responses to the 2025 work, where relevant to its assessment.

16 Interaction with AEMO's frequency control work plan

17 The consultation on changes to the NER for each of these work areas is supported by technical advice provided by AEMO, as part of its frequency control work plan. This work plan provides a cohesive summary of a range of actions that AEMO is undertaking to support

effective frequency control in the NEM as the power system transforms. It sets out AEMO's view of what changes are required to the arrangements for frequency control along with the priority and timing for making these changes.

18 The elements of the AEMO's work plan that directly relate to the frequency control rule changes include:

- **Mandatory PFR rule implementation** – AEMO is in the process of coordinating changes to generator control systems in accordance with the requirements *Mandatory primary frequency response* rule made which commenced in June 2020. This process is being rolled out in three tranches based on the registered capacity of the applicable generating units until mid-2021.
- **FFR implementation options report** – Technical advice on the development of FFR arrangements in the NEM to support the AEMC's assessment of the *Fast frequency response ancillary service market* rule change.
- **PFR incentivisation feasibility report** – Technical advice on enduring arrangements for primary frequency response to support the AEMC's assessment of the *Primary frequency response incentive arrangements* rule change.
- ***Frequency operating standard criteria options analysis*** – Advice on how the frequency operating standard defines the target frequency performance for the power system.

19 Fast frequency response market ancillary service

20 Infigen's rule change request identifies that the projected decline in system inertia will negatively impact on AEMO's ability to control power system frequency. This could result in an increased need for fast FCAS that typically respond to frequency variations within a period of six seconds after a contingency event.

21 Infigen proposes the introduction of new contingency FCAS products that would respond more quickly to changes in power system frequency and better manage frequency variations during reduced inertia operation. Infigen's proposed FFR services would operate in a similar way to existing contingency FCAS, with service provision being based on enablement through the NEM dispatch on a five-minute basis. Infigen proposes an FFR service specification where full active power response is delivered within two seconds, as opposed to the six seconds specification for the existing "fast raise" and "fast lower" services.

22 AEMO's *2020 Integrated system plan* (ISP) forecasts that power system inertia levels will continue to decline as more inverter-based generation plant connect to the power system and existing synchronous plant progressively retire. In addition, AEMO's *Renewable Integration Study stage 1 report* confirms Infigen's view that more and faster frequency responsive contingency reserves are required to keep the power system secure under reduced inertia operation.

23 The Commission's analysis shows, in the absence of changes to the existing market arrangements, that the projected decline in system inertia may lead to a doubling in the requirement for fast raise services by 2025 under the ISP step change scenario or by 2030

under the ISP central scenario.[1] This could lead to a significant increase in the costs for fast FCAS, which could be partially mitigated by the procurement of faster responding services, such as FFR.

24 As noted by the ESB, the development of spot-market arrangements for provision of FFR is preferred. The high level market options for the provision of contingency FFR are:

- Option 1 – new market ancillary services to procure FFR FCAS
- Option 2 – reconfiguration of the FCAS arrangements to procure FFR through the existing service classifications.

25 The Commission is interested in stakeholder views on these high-level FFR options along with a number of other policy considerations discussed in chapter 4 of this paper.

26 One particular area we are interested in stakeholder feedback on is the interaction between FFR and inertia. The consideration of spot market arrangements for inertia is being led through the ESB's essential system services market design initiative and therefore it is not envisaged that a complete arrangement for the valuation of inertia will be developed and implemented through the FFR rule change. However, the interactions between FFR and inertia will be considered as part of this rule change e.g. whether an FFR arrangement could include some valuation for inertial response.

27 Primary frequency response incentive arrangements

28 Background

29 In the period 2014 to 2019, the control of power system frequency during normal operation degraded, such that the power system frequency was spending more time further away from the target frequency of 50Hz than had historically been the case. AEMO identified the degradation of frequency control in the NEM as being driven by a decline in the responsiveness of generation plant to system frequency combined with an increase in the variability of generation and load in the power system.

30 By 16 August 2019, AEMO had formed the view that the decline in frequency control in the power system had reached the point where AEMO was increasingly unable to control the power system frequency under normal operating conditions. AEMO attributed the primary cause for the lack of control as the reduced provision of primary frequency response (PFR) from generation. In its rule change request, *Mandatory primary frequency response*, AEMO considered that there was an immediate need for additional frequency response to restore effective frequency control in the NEM during normal operation and following contingency events.

31 In response to AEMO's rule change request, and a similar request made by Dr Peter Sokolowski, the Commission made the *National Electricity Amendment (Mandatory primary frequency response) Rule 2020.* This rule introduced an obligation for all scheduled and semi-scheduled generators in the NEM to support the secure operation of the power system by

1 The 2020 ISP Central scenario is determined by market forces and current federal and state government policies. The step change scenario incorporates consumer-led and technology-led transitions that occur in the midst of aggressive global decarbonisation. AEMO, *An Overview of AEMO's 2020 Integrated System Plan*, 24 August 2020, p.3.

responding automatically to small changes in power system frequency. In its final determination, the Commission noted that a mandatory requirement for PFR on its own is not a complete solution and that further work needed to be done to understand the power system requirements for maintaining good frequency control. The Commission noted that it would be preferable to introduce alternative or complementary arrangements that incentivise and reward the provision of PFR. As a result, the Commission determined that the Mandatory PFR rule would be an interim arrangement which would sunset on 4 June 2023.

32 AEMO is currently in the process of coordinating changes to generator control systems in accordance with the *Mandatory primary frequency response rule*. The monitoring of plant and power system impacts due to the roll out of the Mandatory PFR requirement will help inform the Commission's determination of the enduring PFR arrangements.

33 Objectives for enduring PFR arrangements

34 The Commission intends to develop enduring arrangements for PFR through its ongoing assessment of AEMO's related rule change request, *Primary frequency response incentive arrangements*. In developing these enduring arrangements, the Commission will:

1. Confirm the **regulatory arrangements** and the role of Mandatory PFR

   This includes consideration of whether or not the Mandatory PFR arrangement should continue beyond the sunset date or be revised as part of an enduring PFR arrangement.
2. Develop **procurement arrangements** for new market ancillary services as required to automatically respond to small frequency deviations in the power system.
3. Develop **pricing arrangements** as required to value and pay providers of PFR
4. Consider the appropriate **cost allocation** approach for primary and secondary frequency regulation services. This includes consideration of potential changes to the existing causer pays process.
5. Consider revisions to the **frequency operating standard** in relation to how the required frequency performance for the power system during normal operation is specified.

35 Pathways toward enduring PFR arrangements

36 This paper considers a number of different policy options for the procurement, pricing and payment for PFR services. There are three viable pathways towards enduring PFR arrangements. These three pathways are defined by three different approaches to the enduring role for mandatory PFR and the associated frequency response band.

37 In summary, the three pathways to enduring PFR are:

1. Maintain the existing Mandatory PFR arrangement with improved PFR pricing.
2. Revise the Mandatory PFR arrangement by widening the frequency response band and develop new FCAS arrangements for the provision of PFR during normal operation (Primary regulating services).
3. Remove the Mandatory PFR arrangement and replace it with alternative market arrangements to procure PFR during normal operation.

38 Subject to the receipt of technical advice that will be informed by the monitoring of the roll-out for the Mandatory PFR arrangements, the initial position is that pathway two is likely to provide a balance between providing operational certainty and system resilience while incorporating new market arrangements that are likely to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of electricity consumers. The arrangements under pathway two incorporate elements of both mandatory and market-based procurement, albeit for different types of PFR. While further detailed policy development is required, this hybrid approach would provide AEMO with additional operational tools and is likely to provide greater flexibility to future power system developments.

39 Accordingly, the initial view is that pathway three is not a preferred approach for the development of enduring PFR arrangements in the NEM, given that a mandatory PFR arrangement provides a valuable safety net against the potential impacts associated with significant non credible contingency events.

40 Timeframes for consultation

41 This paper has been published to facilitate consultation on the two frequency control rule change requests. Submissions in response to these rule changes should be provided to the AEMC by **4 February 2021**.

42 The Commission intends to publish a draft determination for the *Fast frequency response market ancillary service* rule change by **22 April 2021** and a draft determination for the Primary frequency response incentive arrangements rule change by **16 September 2021.**

CONTENTS

APPENDICES

TABLES

FIGURES

1 INTRODUCTION

This paper sets out the Commission's preliminary views and proposed direction for two rule change requests that relate to the arrangements in the NEM for the control of frequency, specifically from:

- AEMO — *Primary frequency response incentive arrangements* [2]
- Infigen's rule change request — *Fast frequency response market ancillary service* [3]

These two rule change requests are referred to collectively in this directions paper as the 'Frequency control rule changes'.

This chapter provides an overview of:

- the purpose for this directions paper and the process for consultation on the frequency control rule changes.
- the rule change requests
- how this work is being coordinated with the Energy Security Board's (ESB) market design initiative related to essential system services as part of its 2025 NEM market design work program
- how AEMO's frequency control work plan will provide important technical information to these processes and
- the structure of this directions paper.

1.1 Purpose of the directions paper

This paper discusses the market and regulatory arrangements that support the control of power system frequency. Frequency control services are a subset of the ESB's essential system services market design initiative, and this paper dovetails and is consistent with the direction of this work.

The paper sets out initial views and high-level policy direction on key issues arising from each of the frequency control rule changes that relate to the arrangements for fast frequency response and primary frequency response in the NEM. The paper identifies key decision points and areas where further investigation and technical input from AEMO will be used to support the Commission's draft determination.

1.2 Process for consultation

The Commission welcomes submissions from stakeholders in response to this directions paper and will use the comments received to inform its draft decision on the rule changes. Submissions will also be used by the ESB's 2025 project to inform its analysis.

Submissions are due **4 February 2021**.

2 Rule change request available on project web page: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

3 Rule change request available on project web page: https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service

We also welcome interested stakeholders to contact us if they would like to meet with us to discuss this consultation paper or any related issues. All enquiries in relation to the Frequency control rule change requests should be directed to Sebastien Henry on sebastien.henry@aemc.gov.au.

1.3 Energy Security Board post 2025 market design

The issues raised in these rule change requests complement and are interdependent with issues being considered by the ESB in its post-2025 market design work.

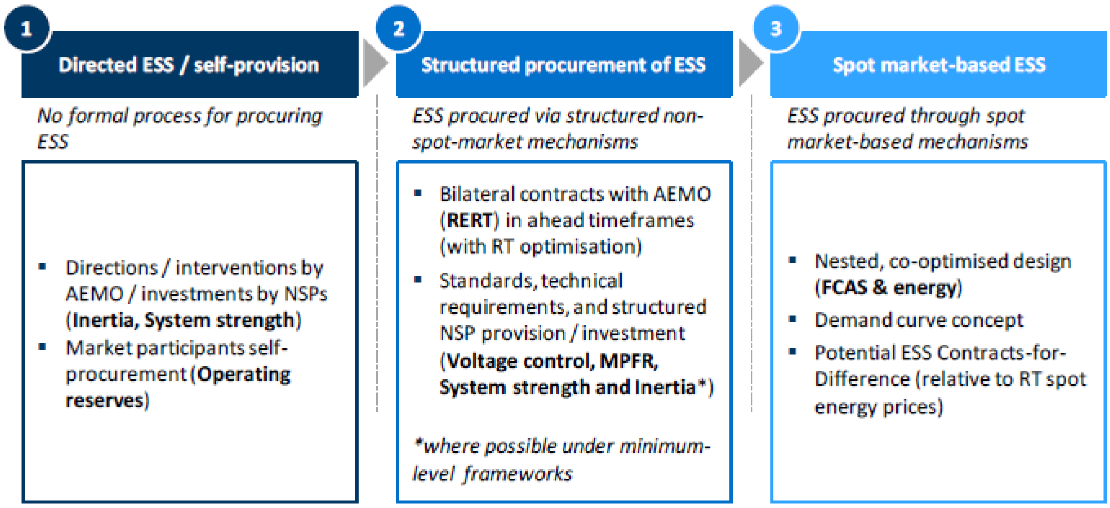
1.3.1 Background to post 2025 market design work

In March 2019, the COAG Energy Council (now the ministerial forum of Energy Ministers) requested the Energy Security Board (ESB) advise on a long-term, fit for purpose market framework to support reliability, modifying the NEM as necessary to meet the needs of future diverse sources of non-dispatchable generation and flexible resources including demand side response, storage and distributed energy resource participation. The post 2025 program has been established as a pathway to a fit for purpose market design for the NEM. The ESB will provide advice to Energy Ministers on changes to the existing market design, or recommend an alternative market design, to enable the provision of the full range of services to customers necessary to deliver a secure, reliable and lower emissions electricity system at least cost by mid-2021.

There are seven core market design initiatives being progressed. Key to this project are the essential system services and scheduling and ahead market work streams.

On 7 September 2020, the ESB published a consultation paper which set out a possible road map for system services for the post-2025 market design. The ESB paper included an overview of work undertaken by FTI Consulting to assist with the formulation of a general framework for the procurement of system services. See Figure 1.1.

Figure 1.1: Procurement options for essential system services



The spectrum of procurement options for ESS, with identification of current provision mechanisms in bold. Source: FTI analysis

Source: FTI, Essential System Services in the NEM, 14 August 2020, p.90.
Note: Reproduced from the *ESB Post 2025 Market design — Consultation paper*, September 2020, p.61.

Given this advice, the ESB's view is that system services for frequency control would lend themselves to being procured through co-optimised real time spot markets similar to existing FCAS arrangements.[4]

The ESB also noted that in the long-term there should be a spot market developed for inertia. This requires further thought however, such as how to deal with the binary nature of inertia provision in that generators cannot incrementally increase their provision of inertia and therefore that inertia can only be increased in the system by committing additional generators to turn on.

These rule changes form part of this work. The AEMC is working closely with the ESB and the other market bodies, particularly AEMO, on these rule change requests given that these rule change requests dovetail with this other work and its direction. The rule change requests complement and are interdependent with the work of the ESB in its 2025 project. These rule changes provide us with an opportunity to complement some of the thinking and assessment done in the ESB work program, as well as technical input from AEMO through its Renewable Integration Study and subsequent work-streams.

To ensure that the various work streams are fully coordinated, the ESB reviews at its monthly Board meeting inter-dependencies between the AEMC rule changes and the 2025 project, prior to critical decision points for each project. Submissions to this paper will be used by the 2025 project to inform its analysis. In progressing these rule changes, the AEMC will consider responses to the 2025 work, where relevant to its assessment.

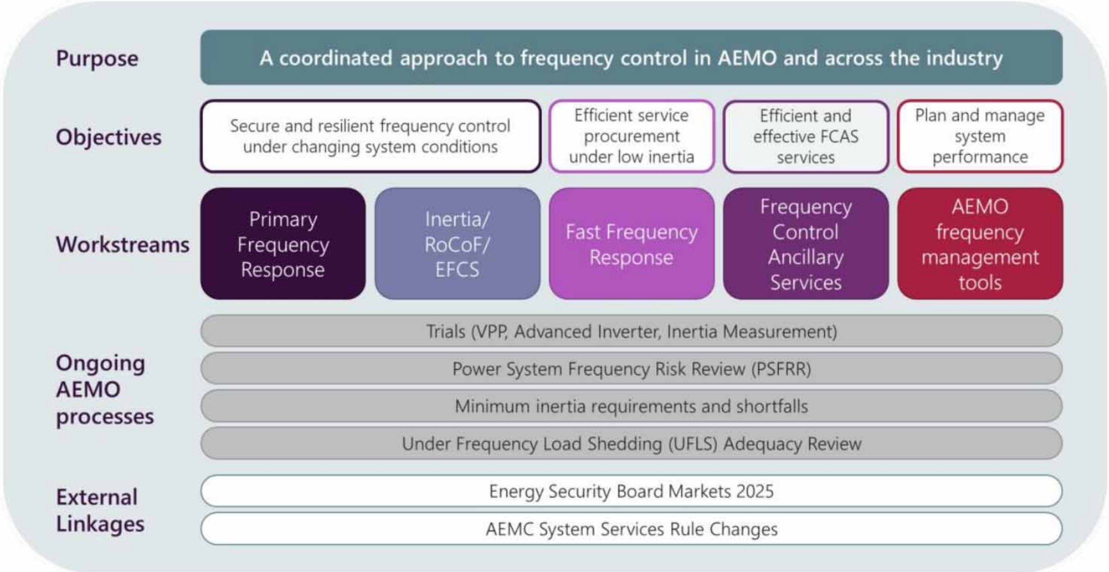
4 Energy Security Board, *ESB Post 2025 Market design — Consultation paper, September 2020, pp.64-67.*

This paper builds on the earlier papers throughout both of the ESB and AEMC's processes.

1.4 AEMO's frequency control work plan

AEMO published its *Frequency control work plan* on 25 September 2020. Following on from AEMO's *Renewable Integration Study stage 1 report*, published in April 2020, the work plan outlines activities related to frequency control that AEMO is undertaking to prepare for and support the changing NEM power system. It sets out AEMO's view of what changes are required to the arrangements for frequency control along with the priority and timing for making these changes.[5]

Figure 1.2: Summary of AEMO's Frequency control work plan



Source: AEMO, Frequency control work plan, 25 September 2020, p.9.

Key elements of the frequency control work plan that relate to the Frequency control rule changes are:

- **Mandatory PFR rule implementation** — AEMO is in the process of coordinating changes to generator control systems in accordance with the *National Electricity Amendment (Mandatory primary frequency response) Rule 2020.* The process is being rolled out in three tranches (by summer 2020/21; by 30 March 2021; by 30 June 2021) based on the registered capacity for applicable generating unit.[6] The monitoring of this process will provide information to the Commission about the effectiveness and costs of the current arrangements for primary frequency response.

5 AEMO, Frequency control work plan, 25 September 2020, p.4.
6 See: https://aemo.com.au/en/initiatives/major-programs/primary-frequency-response

- **Technical advice on fast frequency response** to feed into the Commission's assessment of the *Fast frequency response market ancillary service rule change,* which is due by April 2021, and is further described in section 4.6.
- **Technical advice on primary frequency response** to feed into the Commission's assessment of the *Primary frequency response Incentive arrangements rule change,* which is due by June 2021 and is further described in section 5.5.
- **Frequency Operating Standard (FOS) Criteria Options Analysis**

  This report will outline AEMO's views on whether and how the FOS should be revised to better specify the expected frequency performance of the power system during normal operation. AEMO will provide this advice to the Commission in June 2021, which will be an important input into the Commission's draft determination for the *PFR incentive arrangements rule change*.
- **System inertia safety net investigation** - This investigation relates to AEMO's proposal to consider introduction of an inertia safety net to provide a minimum level of inertia for the mainland NEM under system intact conditions. The introduction of an inertia safety net for the mainland would have implications on the design, implementation and operation of market arrangements for FFR.
- **Review of the Market ancillary service specification**(MASS) - In January 2021, AEMO will commence consultation on incremental changes to the MASS to improve the transparency of the document and the design of the Frequency control ancillary services.[7] Further changes to the MASS may be required following the Commission's determinations for the Frequency control rule changes.

1.5 Infigen's rule change request - *Fast frequency response market ancillary service*

On 19 March 2020, the AEMC received a rule change request from Infigen Energy, *Fast frequency response market ancillary service* (*FFR rule change*), to amend the NER to introduce new market ancillary service arrangements for the procurement of FFR.[8]

The rule change request did not include proposed rule drafting.

A consultation paper seeking stakeholder input was published on 2 July 2020, along with a number of other rule change requests related to the provision of system services in the NEM.[9]

On 24 September 2020, the Commission extended the time-frame to make a draft determination in relation to this rule change request until 22 April 2021. The extended time-frame allows AEMO to undertake technical and market analysis in relation to the development of FFR services for the NEM. AEMO's advice, expected in February 2021, will inform the

7 AEMO, 2021 MASS Review update, 27 November 2021. Available at: https://aemo.com.au/en/initiatives/major-programs/primary-frequency-response

8 Rule change request available on project web page: https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service

9 AEMC, *System services rule changes - consultation paper.* Available at: https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service

Commission's draft determination for the *Fast frequency response market ancillary service* rule change.

The Commission's analysis and views with respect to Infigen's rule change are set out in chapter 4.

1.6 AEMO's rule change request – *Primary frequency response incentive arrangements*

On 3 July 2019, AEMO submitted a rule change request to the AEMC seeking changes to the NER to address perceived disincentives to the voluntary provision of PFR by participants in the NEM.[10] This rule change request was initiated under the project name: *Removal of disincentives to primary frequency response*. In July 2020, the project name was changed to *Primary frequency response incentive arrangements* to reflect the scope and objectives for this rule change request following on from the final determination for the *Mandatory primary frequency response rule*.

The rule change request included a proposed rule.

On 19 September 2019, the AEMC initiated this rule change request and published a consultation paper discussing the related issues.[11] The consultation paper - *PFR rule changes,* also discussed related issues raised in two other rule change requests, one submitted by AEMO and one by Dr. Peter Sokolowski. These other rule change requests were consolidated under the *Mandatory PFR* rule change, and a final determination and rule was published on 26 March 2020. The *Mandatory PFR rule* introduced an obligation for all scheduled and semi-scheduled generators in the NEM to support the secure operation of the power system by responding automatically to small changes in power system frequency. The mandatory PFR requirement came into effect on 4 June 2020 and will sunset on 4 June 2023.

As noted above, on 2 July 2020, the Commission published a consultation paper discussing broader issues related to the provision of system services in the NEM. This provided an update on this rule change, and sought stakeholders' views on, the objectives and directions for the Primary frequency response incentive arrangements rule change.

On 24 September 2020, the Commission extended the time-frame to make a draft determination in relation to this rule change request to 16 September 2021. This extended time-frame allows for AEMO to undertake further work to understand the operational and economic impacts associated with the provision of continuous primary frequency response. AEMO's advice, expected in June 2021, will provide an important input into the AEMC's draft determination for the *Primary frequency response incentive arrangements rule change* on whether and how new incentive arrangements could complement or replace the Mandatory PFR arrangement introduced in June 2020.

10 Rule change request available on project web page: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

11 AEMC, *PFR Rule changes - consultation paper*, 19 September 2019. Available at: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

The Commission's analysis and views with respect to AEMO's rule change are set out in chapter 5.

1.7 Structure of this document

The remainder of this directions paper is structured as follows:

- Chapter 2 provides an overview of the concept of frequency control and how the existing market and regulatory frameworks are set up to enable control of system frequency.
- Chapter 3 sets out the assessment framework for the frequency control rule changes.
- Chapter 4 sets out the Commissions analysis and preliminary views in relation to the FFR rule change.
- Chapter 5 sets out the Commissions analysis and preliminary views in relation to the PFR rule change.
- Chapter 6 outlines the process for lodging a submission to the frequency control rule changes.

2 OVERVIEW OF FREQUENCY CONTROL

This chapter outlines the concepts related to power system frequency control and describes the existing market and regulatory frameworks that support frequency control in the NEM.

2.1 What is frequency control?

In Australia all generation, transmission, distribution and load components connected to the power system are standardised to operate at a nominal system frequency of 50 Hertz (Hz).

Control of power system frequency aims to maintain a steady power system frequency close to 50 Hz during normal operation, and to react quickly and smoothly to stabilise the system frequency following contingency events that cause larger frequency deviations.

The power system frequency will be stable when the electrical power supplied into the system is equal to the instantaneous customer demand, including losses. Changes to the balance of supply and demand for electricity lead to variation of power system frequency as the system speeds up or slows down. Further background on frequency control is available through the energy explained series on AEMO's website.[12]

In each synchronous generating unit, the large rotating mass of the turbine and alternator has a physical **inertia** which must be overcome in order to increase or decrease the rate at which the generator is spinning. In this manner, large conventional generators that are synchronised to the system act to dampen changes in system frequency.

The **rate of change of frequency (Rocof)** following a contingency event, such as the disconnection of a large generating unit, determines the amount of time that is available to arrest the decline or increase in frequency before it moves outside of the permitted operating bands described in the frequency operating standard. In general, more inertia leads to a slower rate of change of frequency and a longer window of time for frequency responsive reserves to act to stabilise the system frequency.

Effective frequency control requires the coordinated application of a range of control actions that are referred to as primary, secondary and tertiary frequency control.

Primary frequency control provides the initial response to frequency disturbances. It reacts quickly and automatically to locally detected changes in system frequency in accordance with agreed parameters. This response is provided by the automatic modification of generator output or customer demand.[13] Continuous primary frequency control helps to control system frequency during normal operation by responding to small frequency variations. Primary frequency control can also be configured to provide active power response only following larger disturbance events, this is referred to as Contingency response.

12 See AEMO's Energy Explained: Frequency Control, 24 June 2020. https://aemo.com.au/en/newsroom/energy-live/energy-explained-frequency-control

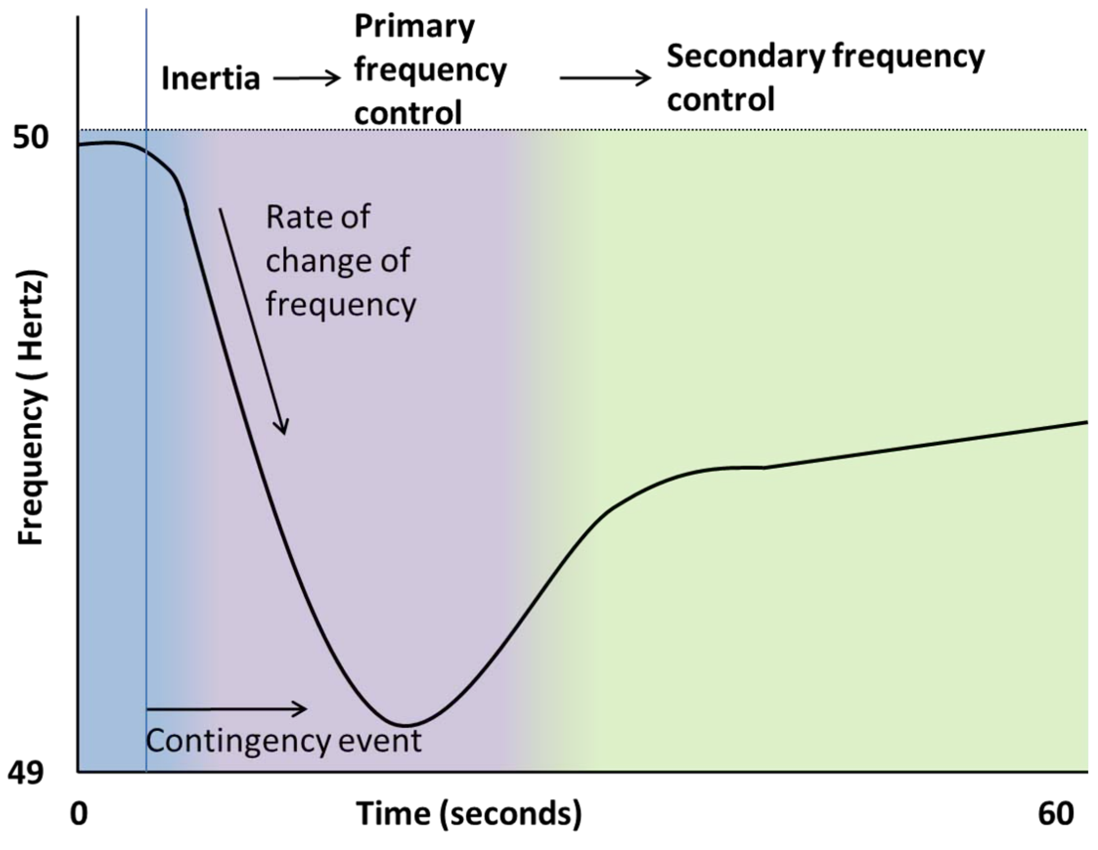
13 International Council on Large Electric Systems (CIGRE), 2010, Ancillary Services: an overview of International Practices, Working Group C5.06, pp.7-8.

Secondary frequency control refers to active power response that is centrally controlled and typically responds in real time, to signals or directions given by the system operator. Secondary frequency control services are intended to respond to frequency variations more slowly than primary frequency control to correct the power system frequency over a period of minutes.

Tertiary frequency control refers to reserve generation capacity that is able to be utilised to reset the primary and secondary frequency control services. This capacity does not automatically respond to frequency, rather it is available reserve that can be called on to restore the system to a secure operating state following contingency events. In the NEM, tertiary reserve is managed through the energy market dispatch, which matches generation supply with forecast demand every five minutes.

The role of these frequency control elements in responding to a contingency event is shown below in figure 2.1.

Figure 2.1: Frequency control following a contingency event



Source: AEMC

The existing arrangements that support frequency control in the NEM are described below in section 2.2.

The ability to maintain control of power system frequency following a contingency event, such as the loss of a large generator, load or transmission line is determined by a number of factors, including:

1. The size of the contingency and the level of system inertia which defines the initial rate of change of frequency (RoCoF).
2. The amount of frequency responsive reserves and the characteristics of those reserves, including speed of response and the length of time the response can be sustained.

2.2 The existing Frequency control frameworks

System security is necessary for the efficient functioning of the power system. Under the National Electricity Law (NEL), AEMO's statutory functions include maintaining and improving power system security.[14]

AEMO is required under the National Electricity Rules (NER) to operate and maintain the power system in a "secure operating state".[15] In order for the electricity system to be in a secure operating state, there are a number of physical parameters that must be maintained within a defined operating range, including an allowance for system recovery following disturbances.

Specifically, AEMO is responsible for maintaining the power system in a **secure operating state** by satisfying the following two conditions:[16]

1. The system parameters, including frequency, voltage and current flows are within the operational limits of the system elements, referred to as a **satisfactory operating state**.
2. The system is able to recover from a credible contingency event or a protected event, in accordance with the power system security standards.[17]

One aspect of this is that AEMO must use its reasonable endeavours to control power system frequency in accordance with the *Frequency operating standard* (FOS).[18] AEMO controls frequency during normal operation and manages the impact of contingency events through a coordinated use of the following mechanisms:

- **Generator technical performance standards (GTPS)** — establish a set of technical standards and a negotiation framework for the connection of registered generators to the power system.
- **Inertia framework** — places an obligation on TNSPs to maintain minimum levels of inertia in areas of the NEM where AEMO has declared there to be a shortfall.

14 See section 49(1)(e) of the NEL

15 NER clause 4.2.6(a)

16 NER cl 4.2.4(a)

17 A protected event is special class of non-credible contingency event which is determined by the Reliability Panel based on an application made by AEMO. Ref NER Cl 4 .2.3 (f). AEMO may use a combination of ex-ante measures; including constraints, directions and dispatch of FCAS; to limit the impacts of a protected event consistent with the post-contingency operating state determined by the Reliability Panel.

18 NER clause 4.4.1(a)

- **Mandatory primary frequency response (MPFR)** — AEMO is in the process of implementing the requirement for all registered generators to respond to frequency deviations, subject to energy availability, outside of a narrow response band close to 50Hz. This is required by the *Mandatory primary frequency response rule 2020,* which came into effect on 4 June 2020 and will sunset on 4 June 2023.
- **Frequency control ancillary services (FCAS**) — provide AEMO with a suite of ancillary services through which frequency responsive reserves are procured to help control system frequency.
- **Emergency frequency control schemes (EFCS)** — These automatic control schemes act to disconnect generation (over frequency generation shedding, OFGS) or load (under frequency load shedding, UFLS) to help re-balance the power system following significant non-credible contingency events.

Further detail on the Mandatory PFR arrangement is included in section 5.1.2. The remaining four elements of the NEM frequency control frameworks are in appendix B.

2.3 Link between inertia and contingency FCAS

AEMO determines the requirement for contingency FCAS volumes based on an assessment of the largest credible system risk adjusting for the impact of load relief.[19] During system intact operation, the current approach does not explicitly recognise a link between the required volumes of frequency responsive reserves and the amount of inertia on the power system.

However, AEMO's recent analysis through its Renewable Integration Study demonstrates that an operational trade-off exists between inertia levels and the requirement for fast responding contingency reserves.[20] A summary of this is included in section 4.5.1.

As part of its *Frequency control work plan*, that was published in September 2020, AEMO has indicated that it intends to implement dynamic constraints for contingency FCAS volumes in Q3/Q4 2021. These new constraints are intended to recognise the link between R6 requirement and the level of inertia for system intact operation of the mainland power system.[21] This will more explicitly link inertia and frequency arrangements.

The focus of Infigen's rule change request on Fast frequency response ancillary service markets is the development of arrangements to provide for FFR to help manage low inertia operation of the power system. However, the Commission notes that separate arrangements for valuation of inertia are being considered through the ESB's essential system services market design initiative. This approach is based on the understanding that inertia is a separate power system variable that requires a separate regulatory arrangement.[22]

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19 The variation of demand due to a change in frequency is known as load relief. When the frequency falls, synchronous motors, such as pumps and compressors, connected to the power system slow down and consume less power. This results in a net reduction in system load. Conversely, if the system frequency increases, the demand for power will increase.

20 AEMO, *Renewable Integration Study – Stage 1 report*, March 2020, p.47.

21 AEMO, *Frequency control work plan*, 25 September 2020, p.11.

22 AEMO, Fast frequency response in the NEM - Working paper, 21 August 2017, p.4.

The Commission invites stakeholder feedback on how an FFR arrangement may interact with existing and future arrangements for inertia and whether inertial response should be valued (implicitly or explicitly) through an FFR arrangement.

The interaction between inertia and FFR is demonstrated by AEMO's approach to the recent declaration of an inertia shortfall in South Australia as described in Box 1.

BOX 1: **AEMO'S INERTIA SHORTFALL DECLARATION FOR SA – 2020 - 2022**

AEMO published a *Notice of South Australia inertia requirements and shortfall* for the SA region on 27 August 2020. As part of the notification AEMO indicated its intention to coordinate with ElectraNet for the provision of FFR through contractual arrangements to help maintain the SA region in a secure operating state when there is a credible risk of separation and during islanded operation. This notification was made under the NER inertia framework which is described in Appendix B.2.

This is the second shortfall notice for SA and applies immediately out to 2021-22.

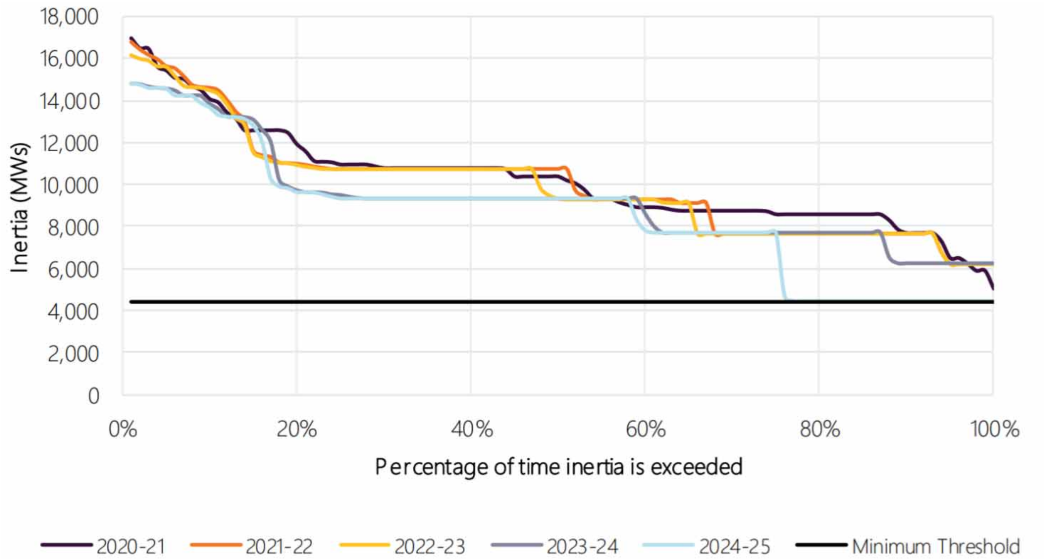
AEMO proposed to resolve the shortfall through the provision of FFR as inertia support activities, which would act to adjust the secure operating level of inertia. This was the first time that AEMO proposed to use the inertia support activities provisions in the NER for the procurement of FFR.

The shortfall notification was based on AEMO's revised assessment of the SA inertia requirements over two stages covering 2020-21 and 2021-22.

- Stage 1 is for the islanded operation of SA prior to the commissioning of four synchronous condensers by ElectraNet expected in Q2 2021.
- Stage 2 is for the islanded operation of SA following the commissioning of the synchronous condensers

AEMO's revised assessment determines that a shortfall exists if the ninety-ninth percentile level of inertia does not exceed the required amount. AEMO's projection of inertia levels for SA are shown in figure 2.2.

Figure 2.2: Projected inertia in the South Australia region 2020 - 2025



Source: AEMO, *Source: Notice of South Australia inertia requirements and shortfall,* Source: August 2020, p.21.

AEMO determined that the minimum threshold level of inertia for SA will remain unchanged at 4,400MWs and that this level of inertia is likely to be met for the period to 2024-25.

However, based on this revised assessment, AEMO has declared an immediate shortfall for the SOLI in SA. The shortfall applies for 2020-21 and is predicted to increase for the period 2021-22. AEMO has not made any forecasts of the inertia requirements in SA beyond 2022, due to high levels of uncertainty regarding the impact of distributed PV beyond this time-frame.

In light of the constraints on the secure outcomes for operation of the SA island, AEMO describes how the SOLI can be adjusted through the addition of FFR being provided by ElectraNet as an inertia support activity, with 115MW of FFR required to satisfy the SOLI in stage 1 (2020-2021) and 200MW of FFR required in stage 2 (2021-2022). AEMO has requested that ElectraNet make available the required inertia support activities (FFR) for stage 1 by October 2020 and for stage 2 by 31 July 2021.

Source: AEMO, *Notice of South Australia inertia requirements and shortfall,* August 2020.

3 ASSESSMENT FRAMEWORK

This chapter sets out the AEMC's framework for the assessment of the frequency control rule change requests, and discusses the system services objective which provides a means of applying the National Electricity Objective (NEO) to system services trade-off decisions.

This assessment framework is based on the framework set out in the System services rule changes - Consultation paper, published on 2 July 2020, incorporating stakeholder feedback made to that process.

3.1 Achieving the National electricity objective

The Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).[23] This is the decision-making framework that the Commission must apply.

The NEO is:[24]

> To promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

3.2 System services objective

The Commission has developed a 'system services objective' in relation to the assessment of these rule change requests against the NEO. It reflects the trade-offs that are expected when considering issues related to the provision of system services.

The **system services objective** seeks to:

> Establish arrangements to optimise the reliable, secure and safe provision of energy in the NEM, such that it is provided at efficient cost to consumers over the long-term, where 'efficient cost' implies the arrangements must promote:
>
> - efficient short-run operation of,
> - efficient short-run use of, and
> - efficient longer-term investment in,
>
> generation facilities, load, storage, networks (i.e. the power system) and other system service capability.

In providing further context for the system services objective:

23 Section 88 of the NEL.

24 Section 7 of the NEL.

- **Promoting efficient operation** refers to factors associated with the ability of the service design option to achieve an optimal combination of inputs to produce the demanded level of the service, at least cost i.e. for a given level of output, the value of those resources (inputs) for this output are minimised.
- **Promoting efficient use** refers to factors associated with the ability of a service design option to allocate limited resources to deliver a service, or the right combination of services, according to consumer preferences (or system need). This may include allocating resources between the provision of multiple services, to achieve an efficient mix of overall service provision. It may also require consideration of meeting multiple system needs, including security, reliability, and resilience.
- **Promoting efficient investment** refers to factors associated with the ability of the service design option to continue to achieve allocative and productive efficiencies, over time. This means developing flexible market and regulatory frameworks, that can adapt to future changes. This involves the following considerations:
  a. It is likely that the technologies that *provide* system services, as well as the technologies that drive the *need* for these services, will change significantly over time.
  b. Technical understanding of these services will also change over time.
  c. The robustness of service design options to climate change mitigation and adaptation risks will also contribute to dynamic efficiency over time.

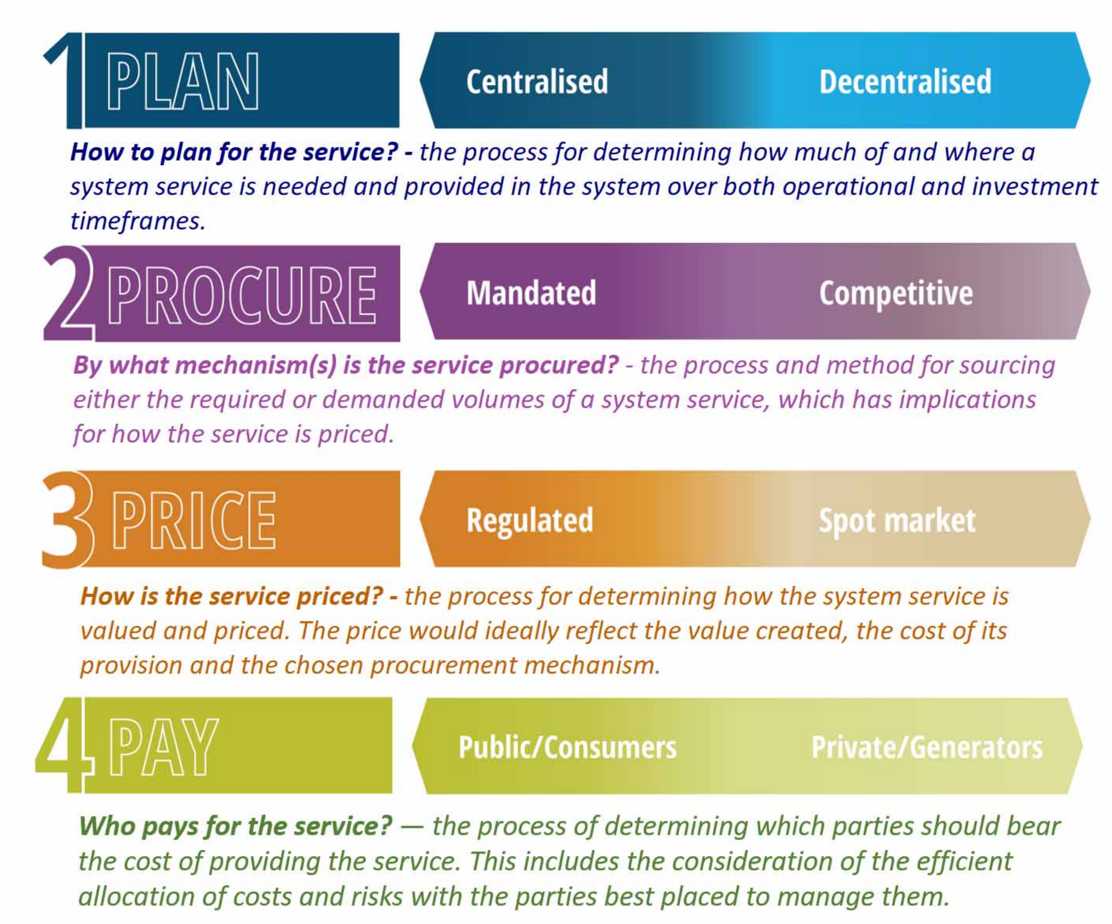
Achieving dynamically efficient outcomes requires flexible regulatory frameworks. The design of these frameworks should show explicit regard for how best to facilitate investment in the operation and use of system services over time, and how allocative and productive efficient outcomes in the short run can be maintained into the future.

3.3 System service design - planning, procuring, pricing and payment

The system services objective is used to assess service design options developed through the '4Ps' service design framework.

The Commission considers the development of new market and regulatory frameworks based on thinking about how system services can be planned for, procured, priced and paid for. Within these categories, there exist a range of options, which are explored in the figure below:

Figure 3.1: Considerations for Planning, Procuring, Pricing and Paying for a system service



Source: AEMC

3.4 Principles for assessment

The Commission will apply the following principles in its assessment of these rule changes:

- **Promoting power system security and reliability:** The operational security of the power system relates to the maintenance of the system within predefined limits for technical parameters such as voltage and frequency. System security - including frequency - underpins the operation of the energy market and the supply of electricity to consumers. Reliability refers to having sufficient capacity to meet consumer needs. It is therefore necessary to have regard to the potential benefits associated with improvements to system security and reliability brought about by the proposed rule changes, weighed against the likely costs.
- **Appropriate risk allocation**: The allocation of risks and the accountability for investment and operational decisions should rest with those parties best placed to manage them. The arrangements that relate to frequency should recognise the technical

and economic characteristics and capabilities of different types of market participants to engage with the system services planning, procurement, pricing and payment. Where practical, operational and investment risks should be borne by market participants, such as businesses, who are better able to manage them.

- **Technology neutral**: Regulatory arrangements should be designed to take into account the full range of potential market and network solutions. They should not be targeted at a particular technology, or be designed with a particular set of technologies in mind. Technologies are changing rapidly, and, to the extent possible, a change in technology should not require a change in regulatory arrangements.
- **Flexibility:** Regulatory arrangements must be flexible to changing market and external conditions. They must be able to remain effective in achieving security outcomes over the long-term in a changing market environment. Where practical, regulatory or policy changes should not be implemented to address issues that arise at a specific point in time. Further, NEM-wide solutions should not be put in place to address issues that have arisen in a specific jurisdiction only. Solutions should be flexible enough to accommodate different circumstances in different jurisdictions. They should be effective in facilitating security outcomes where required, while not imposing undue market or compliance costs.
- **Transparent, predictable and simple:** The market and regulatory arrangements for frequency control should promote transparency and be predictable, so that market participants can make informed and efficient investment and operational decisions. Simple frameworks tend to result in more predictable outcomes and are lower cost to implement, administer and participate in.

4 FAST FREQUENCY RESPONSE MARKET ANCILLARY SERVICE

This chapter sets out the Commission's preliminary views on the process and policy options for implementing arrangements to support the provision of Fast frequency response (FFR) services in the NEM. This discussion relates to Infigen's FFR rule change request which is described in section 1.5.

4.1 What is FFR and its technical characteristics?

FFR generally refers to the delivery of a rapid active power increase or decrease by generation or load in a time frame of two seconds or less, to correct a supply-demand imbalance and assist in managing power system frequency. FFR is a relatively new technology that can be offered by inverter-based technologies such as wind, solar photovoltaics (PV), batteries and demand-side resources.

There are a number of use-cases for FFR as described below in section 4.1.2. However, Infigen's rule change request, and by extension this chapter, is predominantly concerned with the potential application of FFR capability for contingency response in the NEM. The remainder of the chapter therefore, discusses the potential arrangements for the integration of FFR for contingency response.

The following sections summarise related work by AEMO undertaken in 2017 that investigated and reported on potential opportunities for FFR in the NEM, in the context of the changing nature of the power system.

4.1.1 AEMO 2017 — Fast frequency response specification and consultants report

On 13 March 2017, AEMO published a report that it commissioned from GE Consulting that explored the potential value of FFR services in the NEM. This report, *Technology Capabilities for Fast Frequency Response*, discussed the role that FFR could play as a mitigation option for maintaining secure operation in the power system during low inertia operation.[25] Among other things, GE recommended that the implementation of FFR in the NEM should be supported by detailed dynamic power system modelling, including a review of whether the existing system models provided adequate fidelity for simulation of extreme operating conditions.[26]

AEMO published a *Fast frequency response specification* (FFR specification) as an accompaniment to the GE report. The FFR specification provided an interpretation of the findings in the GE report and highlighted the following points that AEMO considered for the technical considerations of FFR at the time:[27]

25 GE Energy Consulting, *Technology Capabilities for Fast Frequency Response*, 15 March 2017, p.1.

26 Ibid., pp.13-14.

27 AEMO*, Fast frequency response specification – Release of GE energy consulting report*, 15 March 2017, p.1-3.

- There are different FFR-type technologies. Some of these such as batteries, flywheels and super-capacitors, can respond very rapidly to a triggering signal (within 40 milliseconds (ms)). Others, such as inertia-based FFR (IBFFR) from wind turbines (extracting the kinetic energy from the drive-train, often termed "synthetic inertia") more typically deliver FFR in one to two seconds.
- FFR services could be considered for two possible purposes in the NEM, each of which would require different technical specifications and regulatory arrangements.
  - as a new type of Frequency Control Ancillary Service (FCAS), assisting with the management of credible contingency events
  - part of an emergency response for managing rare, extreme events, such as the non-credible separation of a region.[28]
- A range of considerations with respect to the specification of FFR was provided, including that any arrangements for FFR should separately recognise raise and lower response, as most technologies are highly asymmetric in their response capabilities.
- A preliminary analysis of FFR capacity was provided, indicating that FFR provided by wind turbines utilising IBFRR systems may be capable of providing FFR capacity in the order of 10% of generation output. This could translate as 1,000MW of FFR capacity during high wind periods where the registered wind generation capacity was in the order of 10,000MW.[29]
- In relation to how FFR interactions with other essential system services, FFR is not a direct substitute for synchronous inertia. While FFR can help control system frequency during low inertia operation, a minimum quantity of synchronous inertia will continue to be required over the medium term.

AEMO identified that further work would be required to develop a more detailed service specification for an FFR service to help manage contingency events in the NEM.[30] Further detail on the potential specification for FFR services will be included in AEMO's *FFR Implementation options report* as described in section 4.6.

4.1.2 AEMO 2017 — Fast frequency response in the NEM — working paper

On 21 August 2017, AEMO published a technical report that outlined technical considerations with respect to FFR. The paper was published as a technical resource for the industry stakeholders to develop a common language around FFR. It provides guidance on the suite of services that could be offered by FFR to assist in the efficient management of power system security. In this paper AEMO defined FFR as:[31]

> Any type of rapid active power increase or decrease by generation or load, in a

28 A credible contingency event is defined in the NER as an event that AEMO considers to be reasonably possible in the surrounding circumstances, such as the unexpected disconnection of a generating unit or a major transmission element. Ref. NER Cl 4.2.3(b). A non-credible contingency event is any other event that is not considered by AEMO to be a credible event, including simultaneous disruptive events such as the complete disconnection of a double circuit transmission line. Ref. NER Cl 4.2.3(c).

29 Current registered wind generation capacity in the NEM is 7,780MW — AEMO *Generation information*, 12 November 2020.

30 AEMO*, Fast frequency response specification — Release of GE energy consulting report*, 15 March 2017, p.3.

31 AEMO, *Fast frequency response in the NEM — Working paper*, 21 August 2017, p.17.

timeframe of less than two seconds, to correct supply-demand imbalances and assist with managing frequency.

AEMO's paper makes the following fundamental observations in relation to FFR:[32]

- **FFR and inertia are different services.** Although FFR has the potential to assist with frequency management at lower levels of system inertia, FFR and inertia are delivered via different physical mechanisms, and play roles that are not directly interchangeable.
- **Faster responses are not necessarily better**. FFR technologies can respond at different rates, and some manufacturers have indicated to AEMO that total response times of 10-20 milliseconds (ms) are possible. Very rapid response of that scale may not be appropriate or desirable in all power system conditions as it may undermine system instability.

AEMO identified the following areas where FFR may provide value in the NEM in approximate order of importance:[33]

- **Emergency FFR** — For arresting frequency following specific rare, extreme events such as non-credible separation of a region. It was noted that this form of FFR is currently being used by AEMO in collaboration with TNSP's through the development of emergency frequency control schemes, such as the South Australian system integrity protection scheme(SIPS).[34]
- **Fast primary frequency control** — for continuous automatic response to small frequency deviations. AEMO identified this option as having promise in assisting in managing security outcomes in the near term.
- **FFR contingency response** — for automatic response to large frequency deviations. AEMO identified this option as showing promise in assisting in managing security outcomes in the near term.
- **Fast response regulation** was identified as being a technically feasible option, but noted that this may become more important in future
- **Simulated or synthetic inertia** were identified as requiring further commercial demonstration — although AEMO noted that the existing inertia framework may be able to be adapted to support the provision of simulated or synthetic inertia. (The inertia framework in the NER establishes a process for the identification and maintenance of minimum levels of inertia to support secure operation for each of the NEM regions following separation and during islanded operation. Further detail on this framework is included in appendix B.2)
- **Grid-forming technologies** — AEMO considered that these showed promise for the future. However, further research and required to develop and demonstrate this technology for application in large power systems (>300MW).

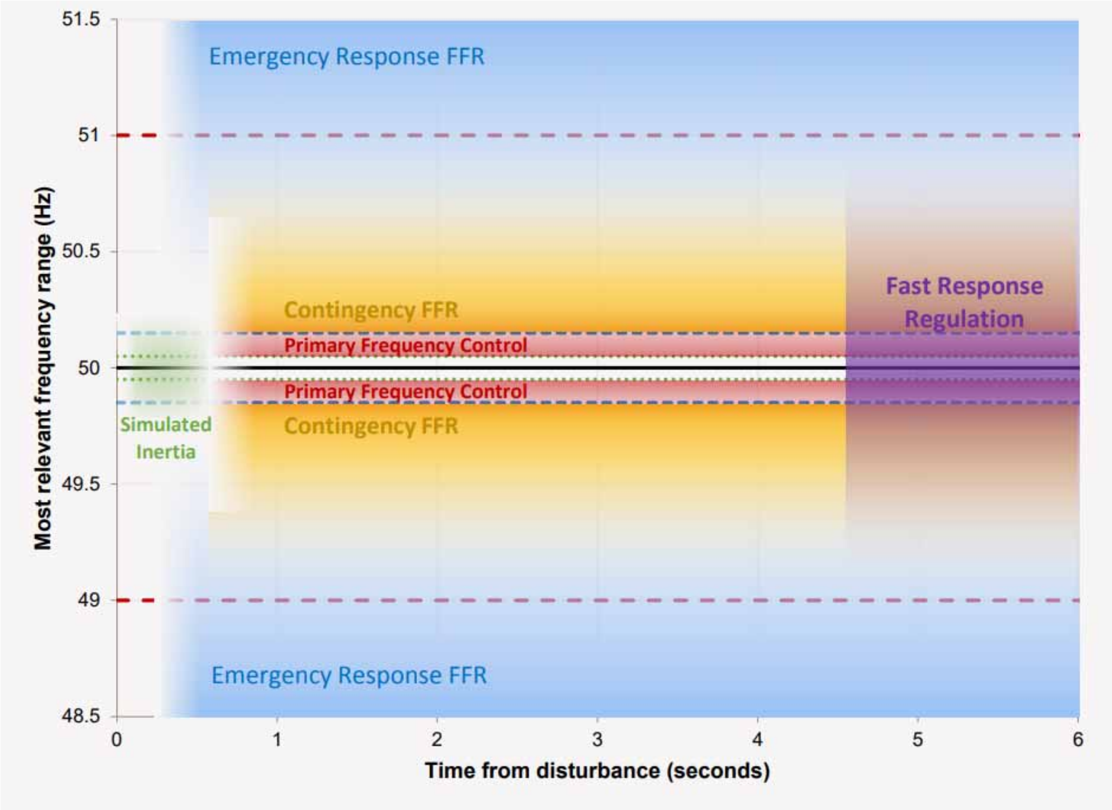
32 Ibid. p.4.

33 Ibid.

34 AEMO, 2020 Power System Frequency Risk Review – Stage 1, 31 July 2020, p.71.

AEMO's mapping of potential applications for FFR is shown below with respect to frequency variation size and response times.

Figure 4.1: Mapping of potential FFR services (frequency ranges and response times)



Source: AEMO, *Fast frequency response in the NEM — Working paper*, 21 August 2017, p.5.

4.2 The rule change request

Infigen Energy rule change request, *Fast frequency response market ancillary service* (*FFR rule change*), seeks to amend the NER to introduce new market ancillary service arrangements for the procurement of FFR.[35]

4.2.1 Problem statement

Infigen considers that inverter-based generating technologies are displacing synchronous thermal generators at certain times of the day and, in some cases, contributing to early retirement of thermal generators.[36] It considers that the cumulative impact of these effects is leading to a steady decline in the amount of inertia that is present on the power system.

35 The rule change request is available on project web page: https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service

36 Infigen Energy Limited, *Fast frequency response market ancillary service — Electricity rule change proposal*, 18 March 2020, p.1-2.

Broadly, Infigen considers that the reduction in system inertia is impacting the ability of AEMO to control power system frequency and the operation of the NEM in two ways:

- **an increase in the instantaneous Rate of change of frequency (RoCoF)**. As synchronous inertia in the power system decreases, the RoCoF following contingency events increases.[37]
- **an increased requirement for six second contingency FCAS** in the absence of faster responding reserves.[38] Higher RoCoF increases the need for more and faster acting frequency response to meet the requirements of the power system frequency operating standard.

Infigen notes that these changes are occurring in the context of an increase in the variability and unpredictability associated with power system operation. Variability in the operation of wind and solar generators as well as more frequent and intense weather events are leading to new and different modes of network failure, with contingency events more likely and their impacts harder to predict. Therefore, Infigen considers that there is an increasing need to develop arrangements to preemptively address power system risks, and that any arrangements for new system services designed to address these issues should occur via transparent market-based frameworks.

4.2.2 Proposed solution

Infigen proposes the introduction of two new faster responding contingency FCAS markets, FFR raise and FFR lower. Infigen considers that the introduction of these new FFR services would provide AEMO with more appropriate tools to manage system frequency following contingency events during low inertia operation.[39]

Under the proposal, FFR providers would respond automatically to any local frequency deviations that occur, and would need to provide their full response within two seconds.

The proposed new FFR service would operate in the same fashion as the existing contingency services. Participants would submit bids to provide the service. AEMO would determine the specifications for the FFR service in the Market Ancillary Services Specification (MASS).[40] The market would be open to generation, loads and aggregators. AEMO would operate the markets similarly to how it operates existing contingency FCAS markets. FFR providers could participate in all FCAS contingency markets (6s, 60s, 5min) and would need to sustain their response for at least six seconds (in time to pass it on to the next 6s contingency FCAS market).[41]

---

37 If the system RoCoF is too fast, the existing FCAS arrangements may not be able to adequately arrest system frequency to prevent load shedding following contingency events. Further-more, protections schemes such as under-frequency load shedding and over-frequency generation shedding may fail to operate as designed which may lead to cascading system failure.

38 Infigen Energy Limited, *Fast frequency response market ancillary service — Electricity rule change proposal*, 18 March 2020, p.3.

39 A contingency event is an event that affects the power system in a way which would likely involve the failure or sudden and unexpected removal from operational service of a generating unit or transmission element.

40 The market ancillary service specification (MASS) is prepared by AEMO in accordance with clause 3.11.2(b) of the NER. It includes a detailed description of each of the market ancillary services together with relevant performance parameters and requirements.

41 Infigen Energy Limited, *Fast frequency response market ancillary service — Electricity rule change proposal*, 18 March 2020, p.5.

According to Infigen, AEMO has indicated that some FFR resources can provide a response in less than 250ms, but Infigen suggests a response time of 0.5 to 2.0 seconds may be necessary to maximise market participation.[42]

Infigen considers that the proposed FFR markets would deliver a price signal to the market that would help support the required investment in FFR capacity that is needed to adequately mitigate the risk of managing future contingency events. Infigen states:[43]

> In our view, it is critical to address these issues now, and before they further impact the reliability of the power system or, alternatively, require greater and more disruptive market changes or interventions.

Faster responding active power response to frequency variations could mitigate the impacts associated with operating the system frequency in a low inertia state. Infigen notes that:[44]

> "While FFR does not (currently) avoid the need for physical inertia, it provides for a broader operating envelope for the grid — allowing for operating with larger contingency events at lower levels of inertia."

If introduced, the volume of FFR, primary frequency response, regulation FCAS, contingency FCAS and inertia required to support the NEM would all be inter-related. Infigen considers that the volume of FFR service should therefore be calculated based on contingency size with consideration of the level of system inertia.[45]

4.3 Previous AEMC consideration of FFR

This section highlights previous consideration of FFR in the NEM by the AEMC.

4.3.1 System security market frameworks review

The *System security market frameworks review* was initiated by the Commission in July 2016 to consider changes to the regulatory frameworks to support the current shift towards new forms of generation in the NEM. The focus of the review was on addressing priority issues to allow the AEMO to continue to maintain power system security as the market transitions. The final report for the *System security market frameworks review* made a number of recommendations that were largely subsequently actioned, which sought to address a number of issues related to frequency arrangements.[46] One of these recommendations included the consideration of how to incorporate FFR services into the FCAS market arrangements.

The final report included the following recommendation in relation to FFR:[47]

42 Ibid

43 Ibid, pp. 2, 4.

44 Ibid.

45 Ibid.

46 AEMC, System security market frameworks review - Final report, 27 June 2017. Available at: https://www.aemc.gov.au/markets-reviews-advice/system-security-market-frameworks-review

47 AEMC, *System security market frameworks review – final report*, 27 June 2017, p.v.

5. Review the structure of FCAS markets, to consider:

- any drivers for changes to the current arrangements, how to most appropriately incorporate FFR services, or alternatively enhancing incentives for FFR services, within the current six second contingency service; and
- any longer-term options to facilitate co-optimisation between FCAS and inertia provision.

This recommendation was to be progressed by the AEMC through its *Frequency control frameworks review* with support from AEMO.

4.3.2 Frequency control frameworks review

Consequently, the AEMC commenced the *Frequency control frameworks review* in July 2017 to explore changes to the market and regulatory frameworks that may be required to meet the challenge of maintaining effective frequency control arising from, and harness the opportunities presented by, the changing generating mix in the power system. In relation to the progression of the FFR recommendation from the *System security market frameworks review*, the *Frequency control frameworks review* recommended action be undertaken by AEMO in relation to how new technologies such as FFR may be valued under the AEMO's Market Ancillary Service Specification (MASS).[48]

> That AEMO[...] conduct a broader review of the MASS that seeks to address any unnecessary barriers to new entrants, or any aspects of the MASS that may not appropriately value services provided by newer technologies where these services are valuable to maintaining power system frequency. This should include consideration of:
>
> 1. the timing specifications for each of the different FCAS
> 2. the overlapping interactions between the different FCAS specifications.
> 3. any changes that may be necessary to settings within the MASS
> 4. issues raised in the most recent review of the MASS that were considered out of scope.

AEMO is planning to commence a review of the MASS in January 2021.[49]

4.4 Stakeholder views

Stakeholder responses to the consultation paper published in July 2020 covered the following key themes:

- Unanimous acceptance of the problem statement in relation to the projected decline of system inertia and the need for reform to support effective and efficient frequency control following contingency events.

48 AEMC, Frequency control frameworks review, 26 July 2018, p.xii.

49 AEMO, 2021 MASS Review update, 27 November 2020. Available at: https://aemo.com.au/en/initiatives/major-programs/primary-frequency-response

- General support for the proposal to develop market ancillary service arrangements for FFR.
- Comments in relation the interactions between arrangements to provide and value inertia and FFR.
- Concerns from energy users in relation to the risk that new system services may contribute to increasing power costs.

Further detail on stakeholder views around these themes is provided below.

Proposed solution

Most stakeholders expressed support for the development of market arrangements to support the provision of FFR in the NEM.[50]

In relation to the development of new market arrangements for FFR, ERM Power noted that:[51]

> While there is no urgent need for these markets now, the time it takes to design, implement and integrate these markets with the existing (and potentially changing) market ancillary services markets means that we consider there would be benefits to doing this now rather than waiting until it is past due.

While AEMO expressed support for the development of spot-market arrangements for the procurement of FFR in the long term, it also noted that there are technical issues associated with FFR that require further investigation. AEMO noted that a contracting approach to procure FFR may be appropriate as a possible first step, prior to the establishment of market arrangements for FFR. AEMO's view is that:[52]

> [contracting] would allow the power system impacts to be managed. It would also allow some flexibility in refining how the service is best utilised and integrated with the possibility of transitioning to a 5-minute spot market.

CS Energy advocated for a holistic review of the framework for frequency control following contingency events including arrangements for the provision of inertia, FFR, PFR and the existing contingency FCAS markets. CS Energy also advocated for the determination of a power system standard for rate of change of frequency (RoCoF) as a transparent guide to the procurement of FFR and inertia.[53] TasNetworks also supported the implementation of a system RoCoF standard to set the operational objectives for the enablement of inertia and FFR services.[54]

50 Submissions to the *Consultation paper – System services rule changes*: Ausgrid, p.4.; ARENA, p.1.; AEMO, p.18.; CEC, p.2.; CleanCo, p. 3.; Enel X, p.3.; ENGIE, p.2.; ERM Power, p.7.; Infigen, pp.2, 19.; Maoneng, p.2.; Snow Hydro, p.7.; TasNetworks, p.4.; Tesla, p.4.; Tilt Renewables, p.2.

51 ERM Power, Submission to the *Consultation paper – System services rule changes, 20 August 2020, p.7.*

52 AEMO, Submission to the *Consultation paper – System services rule changes*, 13 August 2020, pp. 18 – 20.

53 CS Energy, *Submission to the Consultation paper – System services rule changes*, 13 August 2020, p.8.

54 TasNetworks, *Submission to the Consultation paper – System services rule changes*, 13 August 2020, p.4.

Enel X noted that while FFR could potentially be incorporated into the NEM through the re-tasking of the existing fast raise and lower services, it may be preferable to introduce new market ancillary service arrangements for FFR.[55]

Enel X considers there are likely to be benefits in providing AEMO with the flexibility to include additional markets. Adding, rather than replacing, a market is likely to maximise the opportunity for a variety of providers to be able to offer FCAS across the four time specifications.

Meridian Energy expressed general support for Infigen's proposed FFR arrangement, although they noted that further analysis was required to demonstrate that the benefits of implementing a new FFR arrangement are likely to exceed the costs.[56]

Concerns around increased electricity costs

Market customers such as Brickworks did not support the creation of new arrangements for FFR, on the basis that they opposed any measures that would increase the costs or price uncertainty for electricity consumers. Brickworks proposed that the issue of reducing system inertia be addressed through more stringent regulatory obligation on connecting generators, for example that non-synchronous plant be required to provide the level of synchronous inertia required to stabilise the power system.[57]

SACOME and EUAA also expressed a general apprehension for new market arrangements for power system services and the risk that such market reforms may increase power costs for electricity consumers.[58]

Alternative solutions

Monash University noted that the need for FFR is being driven by the reduction in system inertia which in turn is a product of the displacement of synchronous generation plant by non-synchronous renewable generation. Monash proposed that a technical obligation be placed on variable renewable generation to help to control system frequency and thereby "mitigate the frequency fluctuations they are bound to generate". Such an obligation would impose the costs of the FFR for managing low inertia operation on the variable renewable generation.[59]

Similarly SACOME proposed that:[60]

> "it would be most efficient that generators continue to have an obligation to provide and/or procure these ancillary services from the market. Any additional costs to generators can be factored into their bid price, resulting in "smeared" recovery of costs evenly across all market users in a more predictable and efficient manner."

55 Enel X, Submission to the *Consultation paper – System services rule changes*, 13 August 2020, p.4.

56 Meridian Energy Australia, *Submission to the Consultation paper – System services rule changes*, 13 August 2020, pp. 4, 14.

57 Brickworks, Submission to the *Consultation paper – System services rule changes,* 13 August 2020, pp.4-5.

58 EUAA, pp.2-3.; South Australian chamber of mines and energy, p.1-3.

59 Monash energy institute, Submission to the *Consultation paper – System services rule changes,* 12 August 2020*,* pp.8-9.

60 South Australian chamber of mines and energy, Submission to the *Consultation paper – System services rule changes,* 13 August 2020, p.1.

Valuation of inertial response

A number of stakeholders noted that a market ancillary service arrangement for FFR should also include valuation of inertial response, at least as an interim measure in advance of the development of specific arrangements for the valuation of inertia above minimum requirements.[61]

Delta Electricity considered that Infigen's proposed FFR arrangement has two key weaknesses in that it is not technology neutral; and it would not on its own provide sufficient incentives to bring additional capacity into the NEM. Delta's rationale is that the proposed FFR arrangement would "exclude the participation of de-committed slow-start synchronous generators" and that the creation of an FFR service would not provide sufficient incentive for investment in additional capacity for provision of FFR services. Delta considered that the need for FFR can be offset by valuation of inertia provided by large synchronous generators and that this valuation can be at a competitive price if it is packaged with other services such as voltage control and reliability reserves.[62]

4.5 Analysis of the problem

Section 4.5.1 provides an overview of recent technical analysis undertaken by AEMO in its *Renewable Integration Study* showing the projected decrease in power system inertia and how this may drive an increased requirement for fast contingency reserves under the existing MASS specification. In section 4.5.2, the Commission has extended AEMO's analysis to provide an indication of the potential increase in costs associated with R6 services in the absence of any change to the current processes for the procurement of FFR and inertial in the NEM. Finally, section 4.5.3, provides the Commission's view on the problem definition in relation to the *FFR rule change*.

4.5.1 Summary of AEMO's technical analysis

Recently published analysis by AEMO in its *Renewable Integration Study* helps to expand on and confirm the problem statement put forward by Infigen in its rule change request. This analysis helps to further describe the emerging problems related to operating the NEM in the absence of arrangements to provide for FFR.

This analysis shows that, based on the continuation of current market and regulatory arrangements the following impacts will occur to the power system's operation:

- **System inertia is projected to continue to decline**

  AEMO's 2020 Integrated System Plan (ISP) projects declining inertia levels in the national electricity system over the period 2020 through 2035. The projected inertia duration curves under the ISP central and step-change scenario are shown below in Figure 4.2. The figure also includes an unbroken black horizontal line at 45,350MWs which

61 Submissions to the *Consultation paper – System services rule changes:* AEC, pp.2-3.; Stanwell, p.8.; CleanCo, p.3.; Hydro Tasmania, p.4.; OMPS Hydro, p.2.

62 Delta Electricity, Submission to the *Consultation paper – System services rule changes*, 13 August 2020, pp.12-13.

represents the expected level of inertia provided through the existing minimum system strength arrangements.[63]

A dashed line at 65,000MWs indicates AEMO's proposed initial inertia safety net.[64] AEMO has proposed further investigation of an inertia safety net for system intact operation in the order of 55,000MWs to 65,000MWs. AEMO considers that an inertia safety net could be progressively revised as operational experience is built and additional measures are put in place to ensure system security at lower levels of system inertia.[65] The process for the implementation of the proposed inertia safety net is yet to be detailed and further information on this is expected in AEMO's advice, *FFR Implementation options report,* discussed further in section 4.6.

- **The size of frequency deviations following contingency events is expected to increase**

  Under reduced inertia operation, the frequency nadir following a contingency event that results in a loss of generation is expected to become increasingly deep.[66] In the absence of corrective action, AEMO's analysis shows that for mainland inertia levels below 40,000MWs the frequency nadir following the disconnection of a 750MW generator would approach 49.0Hz.[67] 49.0Hz is the lower limit of the containment band specified in the frequency operating standard for a credible contingency event and beyond this point under frequency load shedding commences to help re-balance supply and demand. The impact of reducing system inertia on frequency nadir is demonstrated in Figure 4.3.

- **Increased fast raise FCAS will be required to manage system frequency**

  AEMO's stage 1 report for its Renewable Integration Study shows that for low inertia system operation in the absence of FFR, increased quantities of fast (R6) contingency services will be required to maintain the frequency within the containment bands specified in the frequency operating standard. AEMO's analysis also shows that the provision of faster responding frequency reserves can mitigate the requirement for increased fast (R6) reserves. This is demonstrated in Figure 4.4. The AEMC has undertaken additional analysis to explore this impact further. The results of the AEMC analysis are presented in section 4.5.2.

63 The sum of the regional requirements for the minimum threshold level of inertia for the mainland regions, which applies at all times, is 39,800MWs. The sum of the regional requirements for secure operating level of inertia for the mainland regions is 49,800MWs. However, this requirement only applies on a regional basis during islanded operation, or when there is a credible risk of islanding. It does not impact on system intact operation. Inertia requirements sourced from: AEMO, *Renewable Integration Study – Stage 1 report – Appendix B; Frequency control*, March 2020, p.7.

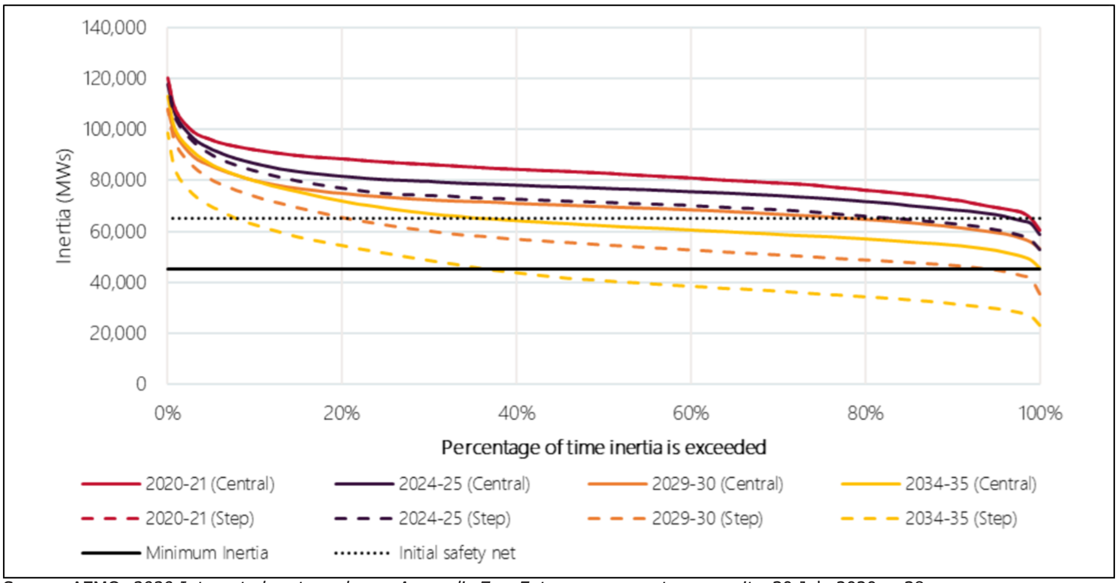
64 AEMO, *Renewable Integration Study — stage 1 report — Appendix B: Frequency control*, 30 April 2020, p.7.

65 AEMO, *Renewable Integration Study – Stage 1 report*, March 2020, p.10, 47-48.

66 The term frequency nadir refers to the lowest value of system frequency immediately following a system disturbance.

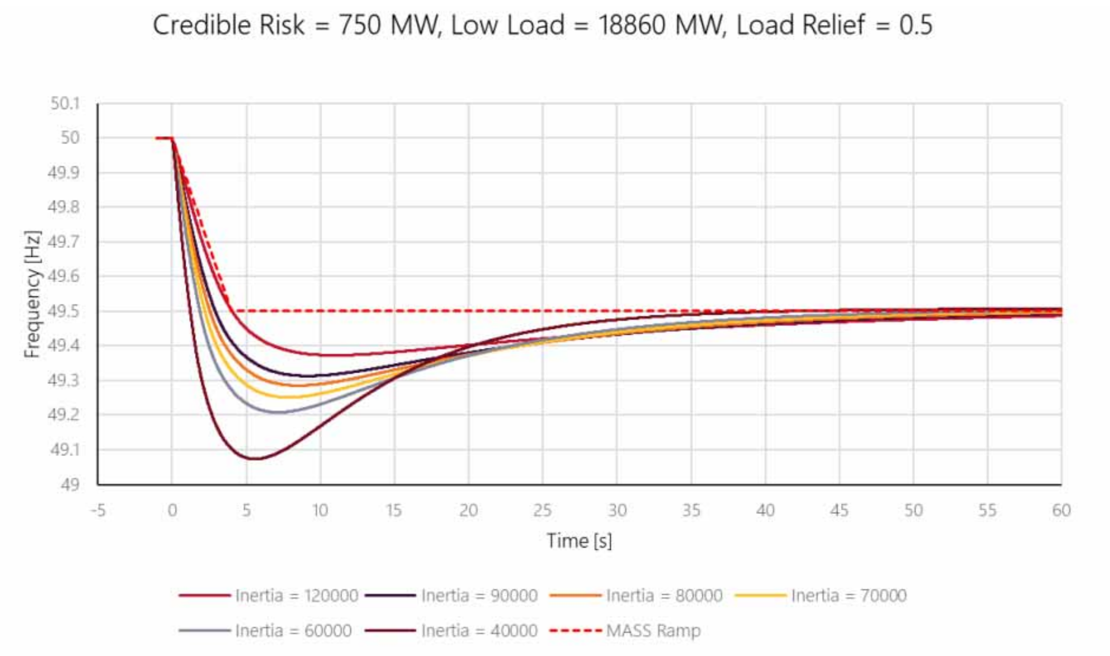
67 The frequency operating standard specifies that the system frequency for the mainland power system be contained within the range 49.5Hz – 50.5Hz for a credible contingency event relating to a generation or load event. The containment band for a credible network event in the mainland NEM is 49.0Hz – 51.0Hz.

Figure 4.2: AEMO ISP projected inertia duration curves for the NEM



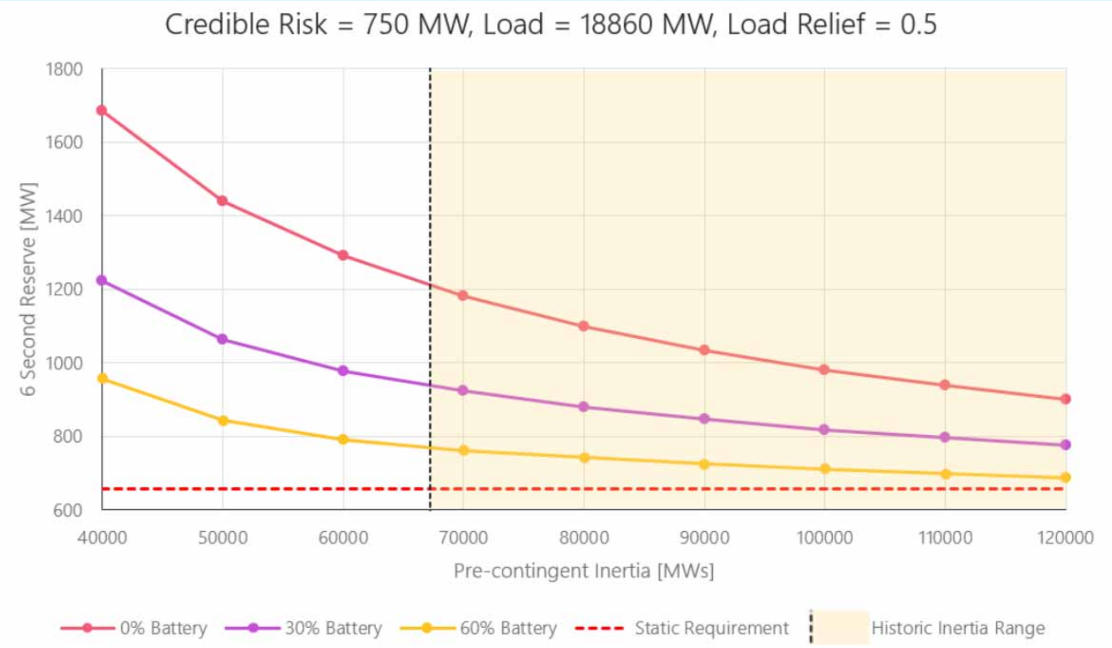
Source: AEMO, *2020 Integrated system plan — Appendix 7 — Future power system security*, 30 July 2020, p.38.
Note: The method and assumptions AEMO's calculation of projected system inertia in the NEM are set out in section A.9.4.4.6 of the 2020 ISP. AEMO, 2020 Integrated system plan — Appendix 9 — ISP methodology, 30 July 2020, pp.24-25.

Figure 4.3: Impact of decreased system inertia on frequency nadir



Source: AEMO, *Renewable Integration Study – Stage 1 report - Appendix B*; Frequency control, March 2020, p.24.

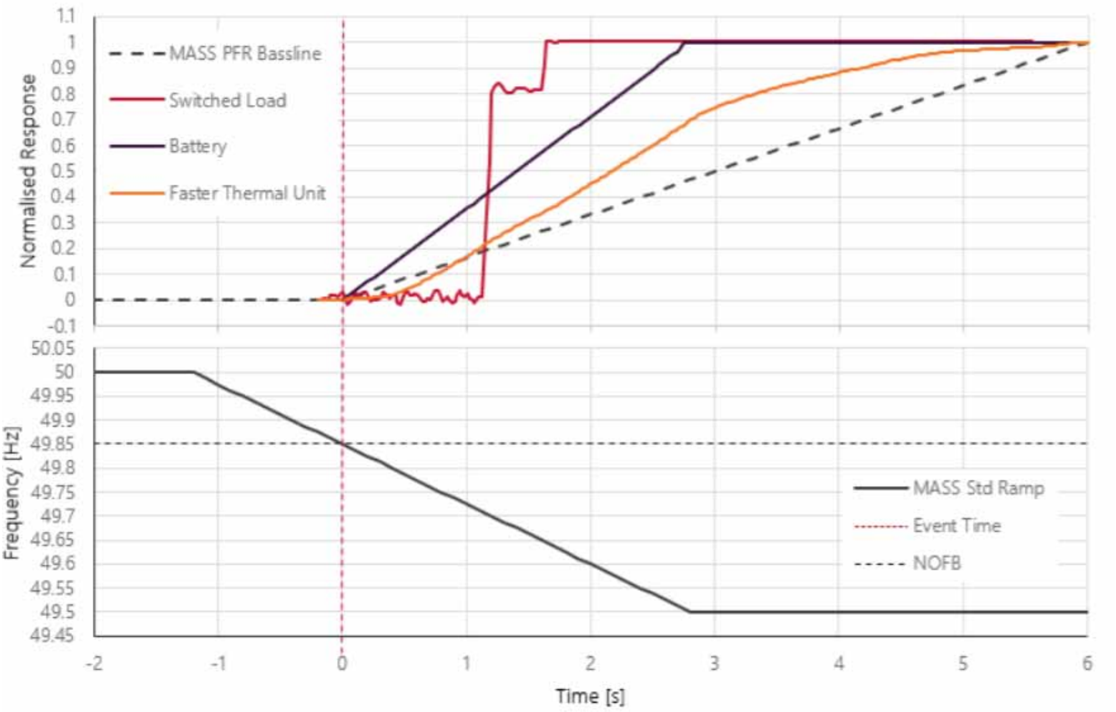
Figure 4.4: Requirement for 6 second raise service vs inertia and the impact of faster response



Source: AEMO, *Renewable Integration Study – Stage 1 report*, March 2020, p.47.
Note: Figure show the impact of increased proportion of R6 requirement provided by battery storage on the R6 reserve requirement. Battery response under the R6 service specification is expected to be faster than standard response.

Figure 4.5 shows the typical unit response for different providers of fast raise FCAS as used by AEMO in its analysis for the *Renewable Integration Study — stage 1 report.* The results in Figure 4.4 show how increasing the proportion of faster six-second (R6) contingency response that is provided from batteries, can mitigate the need for increased fast raise service. It is expected that FFR response provided through an explicit FFR mechanism could be even more effective at mitigating the need for increased fast FCAS to manage system frequency during low inertia operation.

Figure 4.5: Indicative unit response to standard frequency ramp



Source: AEMO, *Renewable Integration Study – Stage 1 report - Appendix B*: Frequency control, March 2020, p.35.

4.5.2 Economic analysis

The AEMC has undertaken further analysis based on the projected decline in system inertia and the relationship between inertia and the need for fast (R6) raise services in the NEM as described in section 4.5.1. The AEMC analysis indicates the scale of the potential increases in requirement for fast raise services in the NEM under a future where the level of inertia in the power system is decreasing but where there are no new arrangements for provision of FFR.

In the absence of changes to the existing market arrangements, the requirement for R6 services is projected to increase as system inertia declines. As described in section 2.3, AEMO intends to implement a process from Q3/Q4 2021 to determine contingency FCAS requirements on a dynamic basis to recognise the link between reserve requirement and inertia.[68]

In the absence of corrective action, the AEMC's analysis indicates that:

- For the ISP central scenario, the dynamic requirement for R6 services would be almost double the static requirement by 2030.
- For the ISP step-change scenario, the dynamic requirement for R6 services would be almost double the static requirement by 2025.

68 AEMO, *Frequency control work plan*, 25 September 2020, p.11.

Based on the historical 5-year average annual revenues for R6 services, the doubling of the R6 requirement could translate into increased costs for R6 services in the order of $60 million per annum in 2020 dollars.[69]

Further detail on the AEMC analysis of the potential economic impacts of inaction with respect to the projected decline in system inertia and the related increase in requirement for R6 is included in appendix A.

These conclusions suggest that the use of R6 as per the existing MASS, is an inefficient tool to manage frequency during lower inertia operation. As a result, the analysis suggests that the cost increase related to the increased requirement for R6 services could be reduced through the optimal dispatch of FFR services, and in future through the co-optimisation of inertia, FFR and R6 services.

The Commission understands that there is significant uncertainty in relation to the projected system inertia levels and the potential impact on requirements for fast raise services. This uncertainty relates to the dynamic nature of the technological transition underway in the power system and the potential impact that changes to the regulatory and market arrangements may have on the projected system characteristics. For example, the implementation of new system services for FFR and inertia is likely to shift the projected increased requirements for R6 services.

The Commission considers that this analysis provides a good indication that the implementation of arrangements to integrate FFR into the NEM can help to mitigate projected increased requirements for R6 services over the coming five to ten years. In particular, the Commission notes that the ISP step change scenario indicates that the potential benefit offered by FFR services will become increasingly material over the next five years, starting from the commencement of the constraints for dynamic FCAS requirements as flagged by AEMO for action in Q3/Q4 2021.[70]

4.5.3 Problem definition and reform objective

Drawing on the analysis set out above, as well as stakeholder feedback, this suggests that:

- The existing market and regulatory arrangements do not explicitly provide for effective utilisation of FFR services to help control system frequency at the lowest cost.
- This constitutes a missing market and does not provide adequate price signals to support efficient investment in the equipment needed for future power system operation
- This issue is particularly the case for system intact operation and is expected to drive increasingly inefficient market outcomes as system inertia levels decline over the period from 2020 through to 2035.

Solutions to this will be addressed and progressed through the ESB's work, of which these rule changes are a part.

69 This indicative analysis does not account for dynamic market impacts such as increased FCAS prices associated with any increased R6 requirement.

70 AEMO, *Frequency control work plan*, 25 September 2020, p.11.

> QUESTION 1: PROBLEM DEFINITION AND REFORM OBJECTIVE — FFR RULE CHANGE
>
> What are stakeholders' views on the problem definition and reform objective for FRR as set out in section 4.5.3 of the directions paper?

4.6 AEMO advice

AEMO has committed to providing technical advice to the AEMC to inform the consideration and development of FFR arrangements for the NEM. This advice is referred to in AEMO's frequency control work plan as the *FFR Implementation options report*.[71] This report will outline AEMO's views on the operational considerations for the integration of FFR into the NEM.

The advice will be provided to the Commission in February 2021 and will provide an important input into the Commission's draft determination.

The Commission understands that the scope of the *FFR Implementation options report* will include AEMO's analysis of technical considerations and a preliminary market analysis to inform the design of FFR market arrangements. The scope of AEMO's advice is outlined below:

Technical considerations

- A description of the operational benefits that could be realised through the development and deployment of FFR services in the NEM.
- Analysis and commentary to describe how inertia and FFR interact in the power system, including further detail on AEMO's proposed inertia safety net for system intact operation and the impact that FFR may have on the setting for the inertia safety net level.
- Investigation of risks and challenges associated with the integration of FFR, including AEMO's preliminary views on possible strategies for mitigation of these risks through constraints or limits on FFR
- An indicative FFR service specification as the basis for investigation of issues related to the integration of FFR.
- Preliminary analysis and commentary on the potential to value inertial response as part of the FFR services.

Input on technical characteristics of market design

- An estimate of current and future FFR capacity availability
- Commentary on the FFR policy options identified in this directions paper including consideration of new or revised market ancillary service arrangements with respect to:
  - Operational feasibility

71 AEMO, *Frequency Control Work Plan*, 25 September 2020, p.11.

    - Consideration of consequential impacts on FCAS specifications as a result of the proposed FFR market design options
    - Impact on provider registration suitability based on the proposed FFR market arrangements (new or revised market ancillary services)
    - The feasibility and applicability of incorporating performance multipliers into the FCAS arrangements to reward FFR
    - Implementation considerations.
- High level modelling of how the preliminary FFR services would interact with existing FCAS, including the estimated requirement for six second raise and lower FCAS for low inertia operation with and without FFR services and the estimated requirement for FFR raise and lower relative to varying levels of system inertia.
- AEMO's views on the feasibility of different policy options for integrating FFR in the NEM including:
    - Introducing new market ancillary service classifications for FFR or revising the existing service specifications for the fast services to include FFR.
    - Use of performance multipliers to value faster active power response within the existing fast services or as part of new FFR services.
- Interactions between FFR and switched frequency response, including discussion of how switched frequency response is similar to or different from FFR and how this relates to the design of the market ancillary service arrangements.
- Discussion of how FFR contingency response should be coordinated with the Mandatory primary frequency response requirement including considerations of frequency response trigger points for FFR, allowance for variable droop and other factors.

Implementation and staging

- AEMO's views on the process for the implementation of FFR arrangements in the NEM.
- AEMO's views on the challenges associated with implementing FFR arrangements and how transitional arrangements could help manage the associated risks.
- Estimated cost for implementation of a new FFR ancillary service market arrangements.

4.7 FFR Policy options

This section describes potential policy arrangements for the integration of FFR into the NEM. This is structured by reference to our assessment framework i.e. how to procure, price, and who should pay for FFR services through the cost allocation arrangements. We are interested in stakeholder views on these policy options, which will inform the ESB and our future work.

4.7.1 Procurement

This section describes initial views on the potential procurement arrangements for FFR that:

- development of spot market arrangements for FFR are preferred.
- There are two options to incorporate spot market arrangements for FFR into the NEM, which include

- Option 1 – new market ancillary services to procure FFR FCAS
- Option 2 – reconfiguration of the existing FCAS arrangements to procure FFR.

Further detail on each of these points is provided below.

Development of spot market arrangements for FFR are preferred

It is appropriate for FFR to be procured through spot market arrangements. In this sense procurement of FFR would be similar to the existing market ancillary service arrangements for contingency FCAS. This approach builds on and is consistent with the framework developed for procurement of essential system services as set out in the essential system services market design initiative in the ESB's 2025 work.[72] This approach is also supported by the majority of stakeholder submissions to the consultation paper.

In its recent *Post 2025 market design consultation paper*, the ESB described the attributes of frequency control services and assessed the degree to which it may be appropriate to procure these services through spot market arrangements. The ESB considered a range of different procurement approaches for system services including operator directions, structured procurement via contractual agreements and procurement through competitive spot market arrangements.[73]

The ESB's initial assessment was that frequency control services are favourable for procurement through spot-market arrangements. This assessment is based on the following findings:[74]

- The volume of frequency control services can be readily defined in MW
- There is good scope for competitive provision of frequency control services, with locational issues limited to regional considerations and generally limited market power concerns
- There is significant international experience for spot market procurement of frequency control services
- Frequency control services can be readily co-optimised with energy and other system services, such as operating reserves.

Also relevant is the market design principles in the NER that underpin the existing market and regulatory arrangements in the NEM and provide a guide to the consideration of changes to the market frameworks, including the development of arrangements for new market ancillary services, such as FFR. The market design principles state that:[75]

> market ancillary services should, to the extent that it is efficient, be acquired through competitive market arrangements and as far as practicable determined on a dynamic basis.

72 *ESB, Post 2025 Market Design - Consultation Paper, 7 September 2020, pp.60-63.*

73 Further information on each of these options can be found in section 6.2 of the ESB's *Post 2025 Market Design — Consultation Paper,* published 7 September 2020, pp.60-63.

74 Ibid., p.67.

75 NER Clause 3.1.4(6)

Where arrangements can function competitively through a market, they are more likely to support the economic dispatch of power system resources and help to reduce the long-term costs of power system operation in the long term interests of electricity consumers. Therefore, these arrangements are preferred where the capability is able to be provided through a market — as it is in this case.

The Commission notes the concerns of large energy users, and consumers more generally, in relation to electricity costs, including the concern that the introduction of new market arrangements for FFR may lead to increases in the price for electricity or the uncertainty associated with electricity bills.[76] However, the Commission does not necessarily agree that costs will increase in total — indeed, our initial economic analysis as outlined above indicates that the introduction of an FFR service is likely to help mitigate future increases in the costs of frequency control services. While there may be increased costs for the provision of FFR, this will likely lead to more efficient outcomes in the wholesale market more generally and so the ultimate impact on consumer bills may be less.

The introduction of FFR services is likely to lead to more efficient dispatch and investment outcomes in the NEM; however, further efficiencies can be achieved through the development of appropriate arrangements for allocation of the costs associated with FFR services. The Commission's preliminary views on cost allocation approaches for FFR services are discussed in section 4.7.3.

FFR market ancillary service options

There are two possible ways in which spot market arrangements could be developed for the provision of FFR in the NEM:

- Option 1 — new market ancillary services to procure FFR FCAS
- Option 2 — reconfiguration of the existing FCAS arrangements to procure FFR.

In each case the existing FCAS arrangements would apply in relation to the following processes:

- The detailed services description and specification would be set out by AEMO in the MASS
- Registration as a service provider would be coordinated by AEMO in a similar manner to the existing process for registration as a Market Ancillary Service Provider

The arrangements would differ in terms of how the market would be operated and the service provided.

These options are described in more detail below.

New market ancillary services for FFR

This option aligns with the proposal put forward in Infigen's rule change request for the development of additional arrangements for FFR raise and FFR lower market ancillary services. The key characteristics of this approach are:

76 Submissions to the *Consultation paper – System services rule changes*: EUAA, pp.2-3.; Brickworks, pp.4-5.; South Australian chamber of mines and energy, p.1-3.

- The two new FFR services would operate alongside the existing eight FCAS markets which could facilitate co-optimised dispatch of FFR with energy and contingency services. There would be ten market ancillary services in total.
- The performance characteristics and operational considerations for the services could be tailored more closely to the provision of FFR.
- The service descriptions in the NER for the existing contingency services and the related service specifications in the MASS would not require any consequential changes. Similarly, the market and settlement arrangements for the existing contingency services would require minimal revision. It is also likely that participant registration for the provision of the existing market ancillary services would be unaffected.
- There may be increased transparency in relation to reporting of market dispatch outcomes including service prices and quantities due to the increased number of service categories.

FFR through the existing market ancillary service arrangements

An alternative to the creation of new market ancillary service arrangements for FFR is the procurement of FFR through the existing FCAS arrangements. It is conceivable that the specification for the existing fast raise and fast lower services could be revised by AEMO to include the provision of FFR. Such an approach would not require the creation of additional market ancillary service classifications under the NER, although supporting changes to the rules may be required to give effect to the desired policy outcome and provide for any transitional arrangements if required. The key characteristics of this approach are:

- There would be no additional market ancillary service classifications required under the NER.
- AEMO would need to broaden the definition for the fast raise and fast lower services more broadly in the MASS to accommodate a range of response speeds from less than 1 second through to the current 6-second bench-mark for full-service delivery. This approach could be supported by differential pricing using performance multipliers, as discussed in section 4.7.2. The implementation of differential pricing may require supporting changes to the NER.
- Consequential changes may be required to the specifications for other contingency services, in particular the slow (60 second) services.
- Changes to the existing service specifications would likely lead to changes in registration eligibility for some market ancillary service providers.
- Changes to the NER may still be required to support the implementation of this approach, including arrangements to manage the transition for the service specification.

The Commission is interested in stakeholder views on these two options for the procurement of FFR, and how each option may interact with the existing FCAS arrangements.

QUESTION 2: FFR PROCUREMENT

In relation to the discussion of potential procurement arrangements for FFR services in section 4.7.1 of the directions paper:

- What are stakeholders' views on the pros and cons of establishing new FCAS market arrangements for FFR services versus revising the existing arrangements to incorporate FFR within the fast raise and fast lower services?
- Do stakeholders agree that the existing arrangements for contingency FCAS provide an appropriate model for FFR market arrangements?
- What are stakeholders' views on how each of the proposed procurement arrangements for FFR would interact with the arrangements for the existing contingency services?
- Are there any aspects of the existing contingency FCAS arrangements that should be varied for procurement of FFR services?

4.7.2 Pricing

This section describes initial views on the potential pricing arrangements for FFR:

- The default pricing arrangements for an FFR spot market would operate in a similar way to the existing FCAS market arrangements.
- The potential benefits of incorporating performance multipliers into the pricing arrangements for FFR services will be investigated.

Further detail on each of these points is provided below.

Where FFR is procured through a spot market process as discussed above, the pricing arrangements would be likely be based on those for the existing market ancillary services. The existing FCAS pricing arrangements have been shown to be relatively fit for purpose over the history of the NEM. However, there is merit in investigating whether the default FCAS pricing arrangements can be improved to maximise the benefits offered by FFR and support efficient market outcomes.

One potential improvement to the existing pricing arrangements could be to use unit-based pricing multipliers that would be applied to the market price to reflect the different value offered to the system by different plant. This concept of differential pricing has been previously investigated by the Commission and is described in the final report for the *System security market frameworks review*.[77]

Existing pricing arrangements for market ancillary services

The existing FCAS market processes utilise competitive bidding by market ancillary service providers to set the price that is paid for provision of each of the FCAS products in each dispatch interval. Under the existing FCAS pricing arrangements, all service providers are paid

77 AEMC, *System security market frameworks review – final report*, 27 June 2017, pp.64-65.

the same price in $/MW/hr for enablement of capacity in each of the FCAS markets, relative to each unit's registered capacity for frequency response in accordance with the MASS.

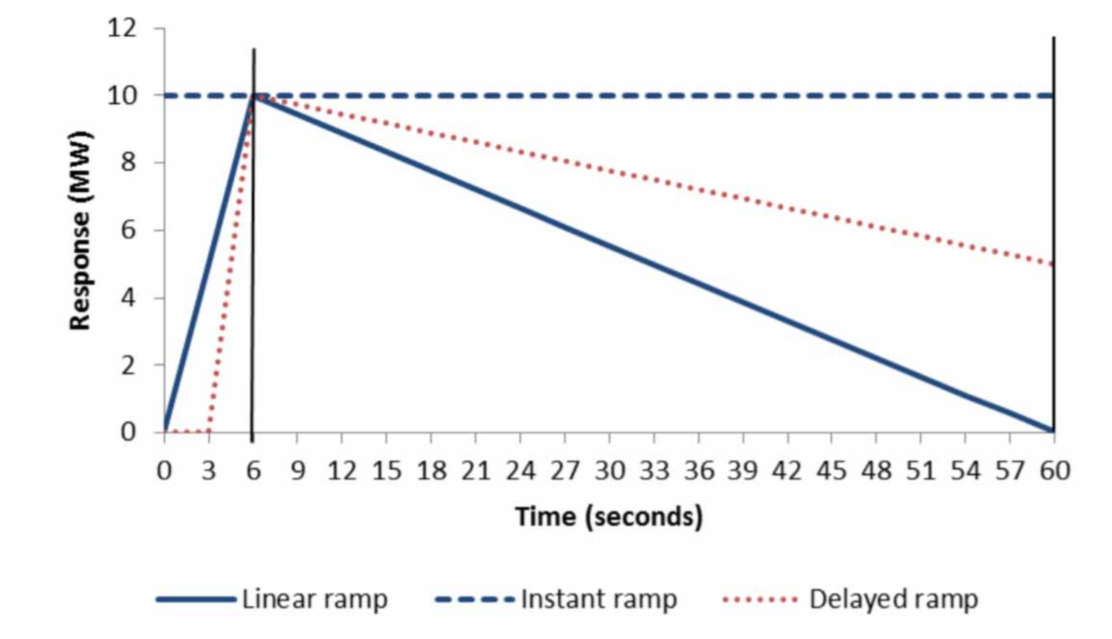
In addition to price differentiation across the FCAS markets, AEMO has some ability to differentially value individual plant through the FCAS registration process, with faster responding providers being valued for more MW of response. This process rewards faster frequency response through a form of volume weighting.

Under the MASS, the current fastest service is the contingency fast raise and lower services otherwise known as R6/L6. This service is intended to arrest a rapid change in system frequency within six seconds of a frequency disturbance, and then provide an orderly transition to slow raise or lower services (which are sixty-second services). The definition of this service is quite flexible in that generator participation simply requires some level of ability to respond to a frequency disturbance in a six-second time frame and to sustain some level of that response for up to sixty-seconds.

Providers of the six-second service are registered for a service capacity (MW) based on the actual energy estimated to be able to be injected over the measurement time-frame. That is, it is the sum of all the energy provided across the time frame of the service. The MASS defines this in terms of the lesser of twice the time average of the response between zero and six seconds and between six and sixty seconds.

The impact of this measurement approach is illustrated in figure 4.6.

Figure 4.6: Volume weighted pricing under the MASS for fast raise (R6) services



Source: AEMC

Figure 4.6 illustrates three possible frequency response profiles, namely linear, instant and delayed ramp profiles. In this example, the maximum energy provided in each case is 10MW within the six-second time-frame. However, the key differences are:

- Under a linear ramp profile, the generator ramps up at a constant rate from time zero to six seconds and then ramps down steadily from six seconds until sixty seconds. Under the MASS this means that the generator will be paid for enabling 10 MW of power as the time average of the ramp up and ramp down are identical.
- Under the instant ramp profile, the generator provides a constant 10 MW over the entire sixty-second time-frame, meaning it is paid an enablement fee for 20MW of power.
- Finally, a delayed response ramp, where the generator takes three seconds to commence response, then follows a linear ramp profile to six seconds and then follows a linear ramp down to sixty seconds. This means the generator is only paid an enablement fee for 5MW. This results from the time average of energy provided from zero to six seconds being half that for the time average of energy provided from six seconds to sixty seconds, and therefore setting the MW target enabled.

The key point arising from the existing FCAS measurement approach outlined above is that it recognises the speed at which FCAS can be provided so that a generator that can provide a faster service will be credited with a higher MW enabled and therefore receive a higher payment than a slower response generator.

This approach does not necessarily recognise any enhanced system value that might be associated with faster response (for example, when there is an identified need for, and a limited supply of, faster FCAS and thus a scarcity premium could apply or where there is a higher opportunity cost associated with enabling a faster FCAS service compared to a slower service).

AEMO has identified that the volume weighted registration approach may present challenges for system operation as the proportion of faster responding plant increase. This approach can allow for faster FCAS providers to be registered for FCAS capacity that is significantly above their actual active power response following a contingency event. This process could potentially contribute to a shortfall in active power response provided following contingency events which would undermine the effectiveness of the FCAS arrangements to arrest and stabilise the system frequency.[78]

The implementation of new FFR service classifications could help mitigate this issue, by increasing the granularity of the service specifications for the market ancillary services. Further flexibility could be provided through differential pricing arrangements.

Differential pricing

Differential pricing would allow for ancillary service prices paid to each market participant to vary based on a scaling factor that reflects the value offered by that individual participant.

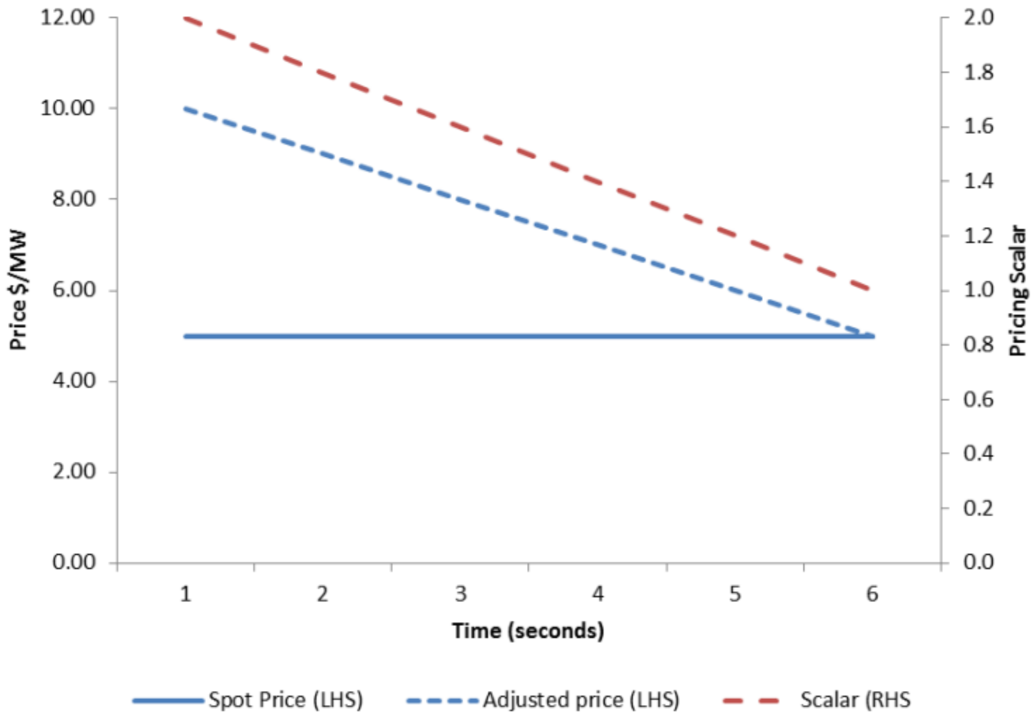
One form of differential pricing involves the application of a pricing scalar based on the speed of active power response to a frequency deviation. This approach is illustrated in Figure 4.7

78 AEMO, *Renewable Integration Study – stage 1 report*, 30 April 2020, p.35.

which depicts a hypothetical application of a scalar multiplier to value faster response under the existing fast R6 service classification. Under this example, a participant that delivered full response by six seconds would receive the base price of $5/MW as shown be the solid blue line. A participant that delivered its full response in one second would receive a pricing scalar of two and be paid a scaled price of $10/MW as shown by the dashed blue line.

This form of differential pricing recognises the different value provided by different service providers based on their individual plant performance as measured by speed of response. It is also possible to determine other metrics for pricing scalars that reflect the relative value of a particular plant response to the power system as a function of location or system conditions.

Figure 4.7: Illustrative pricing scalars - speed of response



Source: AEMC
Note: The red dotted line indicates the scalar multiplier value for response speed. This scalar multiplier has a value of one for an effective response time of six seconds and a value of two for an effective response time of one second.
Note: The blue solid line indicates the spot price for the R6 service, $5 in this instance. The blue dotted line indicates the adjusted R6 price after the pricing scalar is applied.

Examples of markets where scalars are used

Two examples of differential pricing in practise are the arrangements currently used in Ireland and the proposed arrangements for Western Australia.

Pricing scalars are used by Eirgrid in Ireland where scaling factors are applied to the service price based on the plant performance characteristics and the scarcity or need for the specific service characteristics.[79] The provision of FFR and other system services in Eirgrid is managed through the long-term contract arrangements. Contracts are awarded based on a competitive auction and have a six-year term. Payments for services provided are calculated as the product of the available volume, scalars and the base service tariff determined through the auction process.[80]

As part of the energy transformation strategy for the Western Australian wholesale electricity market (WEM), the WA Government is introducing new regulatory arrangements that include a form of differential pricing for contingency services. The new arrangements for the WEM will allow for AEMO to determine a facility performance factor that is applied to the price paid to each facility for provision of contingency reserve services. The facility performance factor in the WEM is defined as:[81]

> the ratio between the Contingency Reserve enabled at the Registered Facility and the Registered Facility's contribution to meeting the Contingency Reserve requirements, where:
>
> (a) a ratio of one denotes that one MW of Contingency Reserve enabled at the Registered Facility contributes one MW to meeting the Contingency Reserve requirement; and
>
> (b) a ratio of less than one denotes that one MW of Contingency Reserve enabled at the Registered Facility contributes less than one MW to meeting the Contingency Reserve requirement.

As the facility performance factors for the WEM are between one and zero, they will act to de-rate a facility's contribution and therefore facilities who receive a performance factor less than one will receive a reduced service price. The Commission understands that AEMO plans to determine the facility performance factors in the WEM based on the following two elements:[82]

- a predetermined facility speed factor, based on speed of response to a standard frequency disturbance
- a predetermined function to calculate a facility performance factor for each dispatch interval. The function will be based on facility speed factor, size of the largest credible risk, system inertia, and system load.

Preliminary views on pricing arrangements for FFR

As noted above, the default pricing approach for FFR services in the NEM would be similar to the pricing arrangements that are used for the operation of the existing FCAS markets.

79 Eirgrid, DS3 System Services Protocol – Volume Capped Arrangements - DS3 System Services Implementation Project, May 2019, p.4.

80 Aurora energy research, Aurora news brief - October 2019 available at: https://www.auroraer.com/insight/ireland-first-ds3-fixed-contract-auction/

81 Energy Policy WA, CONSOLIDATED DRAFT AMENDING RULES FOR WEM REFORMS "TRANCHE 1", 24 July 2020.

82 WA Government – Energy transformation implementation unit, Transformation Design and Operation Working Group Meeting 4 – meeting slides, 19 November 2019. Link.

Incorporating some form of differential pricing into the pricing arrangements however, may provide increased flexibility as the service price can be tailored to the specific unit characteristics for each service provider. The implementation of a differential pricing arrangement in the NEM would require a change to the NER to allow for the determination and application of facility performance factors by AEMO. The detailed process for determining scaling factors could then be specified by AEMO through the MASS.

The benefits offered by differential pricing would be increased under a procurement model that maintained the existing eight market ancillary services. Under this approach, the service specification for the existing fast services could be broadened to allow for a range of response speeds and facility performance factors could be developed to help determine the dispatch and pricing outcomes.

Alternatively, if new market ancillary service classifications were established for FFR services, then there may be less need for the establishment of facility performance factors. This is due to the increased granularity offered by the additional service categories. However, even under this approach there may still be benefits associated with the NER allowing AEMO to incorporate facility performance factors into the process for registration, dispatch and pricing of market ancillary services.

The Commission is interested in stakeholder views on the concept of facility performance factors for FCAS pricing, either as a complement to the development of new market ancillary service classifications for FFR market arrangements or as an alternative approach to reward faster response, without the need to develop new market classifications.

QUESTION 3: FFR PRICING ARRANGEMENTS

In relation to the discussion of potential pricing arrangements for FFR services in section 4.7.2 of the directions paper:

- What are stakeholders' views on the pros and cons of maintaining the existing FCAS pricing arrangements for FFR services?
- What are stakeholders' views on the potential pros and cons of incorporating performance based multipliers into the pricing arrangements for FFR services?
- Do stakeholders have any other comments or suggestions in relation to the pricing arrangements for FFR services?

4.7.3 Cost allocation (payment)

As shown in section 4.5.2, the Commission's preliminary economic analysis indicates that the implementation of arrangements to provide for FFR are likely to reduce the overall long term costs of market ancillary services in the NEM. At the same time, it will be necessary for the Commission to consider the appropriate arrangements for allocation of costs incurred for the provision of FFR as part of the development of any new or revised market arrangements. The

NEM market design principles in chapter three of the NER provide some guidance in this regard where it is stated that:[83]

> where arrangements require participants to pay a proportion of *AEMO* costs for *ancillary services*, charges should where possible be allocated to provide incentives to lower overall costs of the NEM. Costs unable to be reasonably allocated this way should be apportioned as broadly as possible whilst minimising distortions to production, consumption and investment decisions

The following sub-sections outline the Commission's preliminary analysis as a guide to the development of cost allocation arrangements for FFR services:

- The existing arrangements for allocation of contingency FCAS costs
- The beneficiaries and/or causers of the need for FFR services
- The Commission's preliminary view on arrangements for allocation of FFR costs.

The Commission is seeking stakeholder views on these issues to inform the development of arrangements for the allocation of costs associated with FFR services.

The existing arrangements for allocation of contingency service costs

The existing arrangements for allocation of contingency FCAS costs provide a starting point for potential cost allocation arrangements for FFR services.

Under the NER, the costs of contingency services are allocated based on a loosely applied causer pays principle. Costs for contingency raise services are recovered from registered generators and costs of lower services are recovered from market customers.[84]

This arrangement has been in place since the commencement of the FCAS market arrangements, following the approval and determination by the Australian Competition and Consumer Commission (ACCC) in July 2001. As part of its determination, the ACCC noted it supported the causer pays based principle for allocation of ancillary service costs, but that it was not technically feasible to allocate contingency FCAS cost in a better way at the time.[85]

Beneficiaries and causers

In considering the cost allocation arrangements for FFR it is worthwhile to consider who benefits from FFR services and who or what drives the need for these services.

In terms of beneficiaries, all market participants, including generators and customers benefit from the provision of power system services, including FFR. This is because all market participants benefit from the power system being maintained in a secure operating state, such that it can be resilient to frequency disturbances caused by contingency events.

83 NER clause 3.1.4 (a) (8)

84 NER clause 3.1.4 (f) & clause 3.1.4 (g)

85 ACCC, *Applications for Authorisation - National Electricity Code - Ancillary Services Amendments - Determination*, 11 July 2001, p.34.

The fundamental purpose of FFR services is similar to that of the existing FCAS contingency services, which is to protect the power system from the costs associated with frequency disturbances associated with contingency events.

Ultimately, the possibility of contingency events give rise to the need for contingency services. The sudden trip of a generator requires that raise services are available to correct under-frequency deviations and the sudden loss of loads requires that lower services are available to correct over-frequency deviations. Contingency FCAS is required to be enabled at all times to cater for the possibility of a disturbance. The existing arrangement for allocation of contingency FCAS costs are based on the view that need for the FCAS is not readily attributable to any individual generator or load. On this basis, and as described further below, the existing arrangements seek to broadly apply the costs of raise services to generators and the costs of lower services to loads.

However, there is also a connection between the need for FFR and the reduction of synchronous inertia on the power system, as noted by Infigen in its rule change request and evidenced by AEMO through the technical studies published in the *Renewable Integration Study – stage 1 report*. As outlined in section 4.5.2, the projected reduction in system inertia is expected to lead to an increased requirement for fast raise services and an expected increase in costs for procurement of fast contingency services. This impact can be mitigated by the provision of FFR.

It may be appropriate for the FFR cost allocation arrangements to recognise the linkage between the reduction in inertia and the need for FFR. This rationale could lead to the allocation of FFR costs being weighted based on the degree to which a participant causes the need for FFR. In theory, a market participant that provides physical or synthetic inertia may be assessed as not causing the need for FFR and therefor allocated less of a share of costs for FFR.

This approach may be more appropriate in the absence of specific arrangements to value inertial response. However, the rationale for this approach may change following the implementation of arrangements to value inertia and co-optimise its provision with other system services including FFR.

Initial view's

As the proposed FFR services perform a similar function to the existing contingency services, the existing cost allocation arrangements for contingency raise and lower services provide a basis for the allocation of costs associated with FFR services.

The Commission is interested in stakeholder views on the potential cost allocation arrangements for FFR services, including views as to the appropriateness of extending the existing cost allocation arrangements for contingency services allocation of any costs associated with new market ancillary service arrangements for FFR.

> QUESTION 4: FFR COST ALLOCATION
>
> In relation to the discussion of arrangements for the allocation of costs associated with FFR services set out in section 4.7.3 of the directions paper:
>
> - What are stakeholders' views on the arrangements for the allocation of costs for FFR services?
> - Would it be appropriate for the cost of FFR services to be allocated in a similar way to the existing arrangements for the allocation of contingency FCAS costs?

4.8 Issues for consideration

A number of additional issues for consideration in relation to the development of spot market arrangements for FFR. These are discussed further below.

Stakeholders are encouraged to comment on these issues as well as any other aspect of the rule change request or this paper.

> QUESTION 5: ISSUES FOR CONSIDERATION - FFR
>
> Are stakeholders aware of any additional issues that the Commission should take into account in developing market ancillary service arrangements for FFR?

4.8.1 Valuation of inertial response

The existing NER do not support the full valuation of inertia above minimum levels. The NER includes an inertia framework that supports the provision of inertia to meet the power system requirements for satisfactory and secure operation for each of the NEM regions, referred to as inertia sub-networks. This framework is described in appendix B.2. The existing inertia framework provides a minimum level of inertia for safe and secure operation of each of the NEM regions. However, any further market and security benefit that could be obtained through the provision of additional inertia is not yet valued in the NEM.

The development of a co-optimised spot-market arrangement for valuation of inertia has been identified by the ESB as an objective for development through the post-2025 market design process.[86] Whereas the development of FFR market arrangements is relatively discrete in nature, consideration of a market arrangement for inertia is more complex due to inter-dependencies with other elements of the essential system services work-stream, including potential arrangements for unit commitment and provision of synchronous services. The market arrangements for inertia are being considered through the ESB's post-2025 work program. However, the development of FFR arrangements will need to take account of, and

86 Energy Security Board, *Post 2025 Market Design — Consultation Paper*, September 2020, p.59.

consider, a potential future inertia market in order promote coordination and implementation efficiencies.

As outlined in section 4.4, a number of stakeholders have proposed that a new FFR market ancillary service should be technology neutral and that the valuation of inertial response through the FFR arrangement would support a technology neutral outcome.[87] This is a different to the valuation of frequency responsive capacity under the current MASS that explicitly excludes inertial response for the fast, slow and delayed services.[88]

The NER does not include any guidance or requirements in relation to the treatment of inertial response with respect to the existing market ancillary services. The issue of valuation of inertia under the MASS was raised through AEMO's recent consultation on the MASS and has been identified for further consideration as part of a broader review of the MASS.[89] As part of its broader frequency control work plan, AEMO has indicated that it will commence a review of the MASS in January 2021, stakeholders are encouraged to engage with AEMO through this upcoming consultation.[90]

System service arrangements that are technology neutral are preferred and in the absence of separate arrangements for valuation of inertia, it may be appropriate for inertial response to be valued as part of new market arrangements for FFR. However, there are challenges associated with this proposal that require further investigation. For example, FFR contingency reserves are measured in MW, whereas inertia is measured in MW seconds as noted by AEMO in its submission to the consultation paper.[91]

It is not envisaged that a complete arrangement for the valuation of inertia will be developed and implemented through the FFR rule change. As noted above, the consideration of spot market arrangements for inertia is being led through the ESB's essential system services market design initiative. However, the interactions between FFR and inertia will be considered as part of this rule change; e.g. whether an FFR arrangement could include some valuation for inertial response and the Commission is interested in stakeholders' views on this.

QUESTION 6: VALUATION OF INERTIAL RESPONSE

In relation to the potential arrangements for the valuation of inertial response described in section 4.8.1 of the directions paper:

- What are stakeholders' views on the valuation of inertial response as part of the contingency services, including the proposed new FFR contingency services?

87 Submissions to the *Consultation paper – System services rule changes:* AEC, pp.2-3.; Stanwell, p.8.; CleanCo, p.3.; Hydro Tasmania, p.4.; OMPS Hydro, p.2.

88 AEMO, Market ancillary service specification V 6.0, pp. 10, 13-14, 16, 18.

89 AEMO, *Market Ancillary Service Specification and Causer Pays Procedure – Draft Determination*, February 2020, p.4.

90 AEMO, 2021 MASS Review update, 27 November 2021. Available at: https://aemo.com.au/en/initiatives/major-programs/primary-frequency-response

91 AEMO, Submission to the *Consultation paper — System services rule changes*, 13 August 2020, p.18.

- What are stakeholders' views on the current governance arrangements for contingency services; where the detailed service specification is determined by AEMO and documented in the MASS? (Is it appropriate for the NER to provide further guidance on how inertial response should be considered in the MASS?)

4.8.2 Price responsive demand for contingency services (demand curve)

A potential further improvement to the existing arrangements for the procurement of contingency FCAS would be for the NER to recognise and support the procurement of a variable quantity of service subject to the costs and benefits for providing the service. The existing arrangements support the dispatch of sufficient quantities of frequency responsive reserves to meet the operational requirements defined in the frequency operating standard.[92] This effectively sets a minimum requirement for FCAS in each dispatch interval.

The ESB identified that an additional increase in the resilience of the power system to contingency events could be realised through procurement of additional frequency responsive reserves when the price of those reserves is low and they present good value to consumers. This "demand curve" concept has been developed as part of the ESB's work on its 2025 project. The ESB's September consultation paper set out how the existing market ancillary service arrangements for FCAS could be extended to allow for the variation of the quantity of FCAS procured based on the price of the services. As noted:[93]

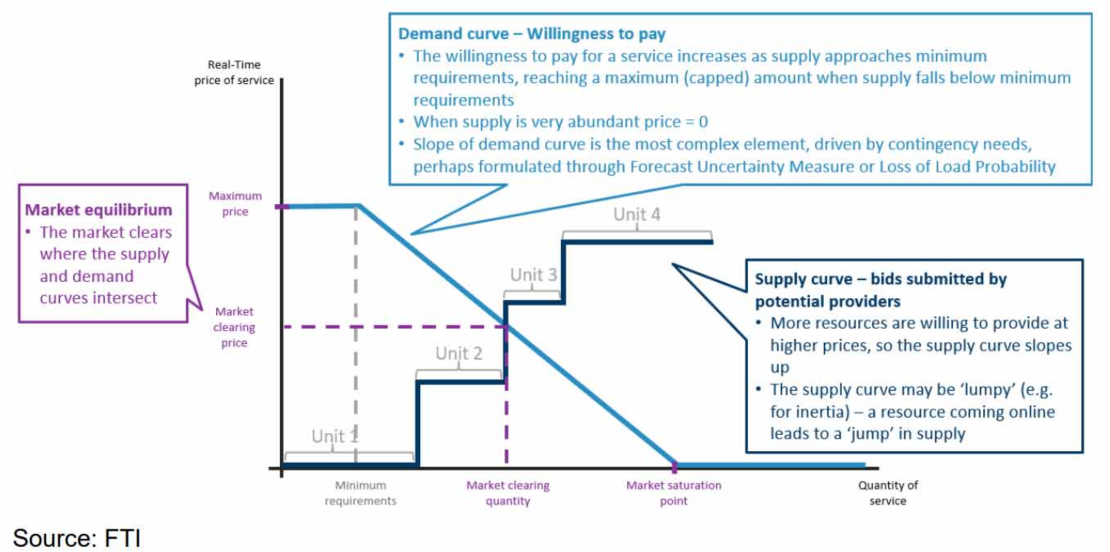
> The key advantage of a demand curve approach is that it maximises the value of procurement, setting a minimum requirement when the price is high and procuring more of a service when efficient to do so.

As illustrated in Figure 4.8 below, the demand curve approach to the procurement of FCAS would include the definition of a minimum requirement for each service along with a predetermined demand function that reflects the value provided by additional quantities of frequency responsive reserve over and above the minimum requirement.

92 NER Clause 4.4.1 & Clause 4.4.2.

93 COAG Energy Security Board, *Post 2025 market design – consultation paper*, September 2020, p.63.

Figure 4.8: Conceptual price responsive demand curve for system services



Source: Energy Security Board, *Post 2025 market design – consultation paper*, September 2020, p.63.

Preliminary views

AEMO can already determine the required quantity for market ancillary services based on its assessment of the power system needs for the purpose of maintaining system security. The demand curve concept would go further and allow for additional quantities of FCAS to be procured when prices were low. The intention would be that the benefit to consumers from increased power system resilience would exceed the costs for the additional FCAS above the minimum requirement.

The implementation of a demand curve concept could apply generally to the procurement of each of the market ancillary services, not just FFR. This approach to FCAS procurement would require the establishment of a supporting framework in the NER which would include a process for the determination of demand curves outside of the existing market arrangements. Under such a framework it is likely that AEMO would be responsible for developing the detailed procedures for the application of the price responsive demand along with the related demand curves for each of the market ancillary services. Such a process would likely be guided by principles set out in the NER, with a potential role for the AER to assess the costs and benefits of the proposed FCAS demand curves.

Further consideration of the costs and benefits associated with the demand curve concept is required in the context of the NEM, prior to progression of any related change to the regulatory framework. The Commission is working with AEMO to obtain estimates of costs of such an approach.

> QUESTION 7: PRICE RESPONSIVE DEMAND FOR CONTINGENCY SERVICES
>
> In relation to the discussion of arrangements for incorporating price responsiveness into the procurement of contingency services in the NEM set out in section 4.8.2:
>
> - What are stakeholders' views on the potential pros and cons associated with the implementation of a "demand curve" approach to procurement of FCAS?
> - What are stakeholders' views on the priority of such a change to the market frameworks?
> - If such an approach was to be implemented, what are stakeholders' views on the appropriate governance arrangements, including the potential oversight role for the AER?

4.8.3 Interaction between mandatory PFR and new FFR services

There is the potential for a new FFR arrangement to interact with a mandatory requirement for PFR.[94] In particular, where there is a mandatory requirement outside of a narrow frequency response band very close to 50 Hz, this may also see FFR being provided at a narrow band.[95] In these circumstances, there is the potential for enabled capacity for FFR could be dis-proportionally utilised to respond to small frequency variations during normal operation. Frequent use of the service may undermine its effectiveness at responding to larger frequency deviations caused by contingency events.

One approach to this issue may be to apply a mandatory obligation on generators which requires them to provide a less aggressive response at narrower frequency bands. This, 'variable droop', approach to frequency response is incorporated into the mandatory PFR arrangements in the NEM, as described in section 5.4.1 of this paper. The variable droop approach is also demonstrated through the FFR arrangements recently adopted by the UK National Grid.[96] National Grid's dynamic containment service is a form of FFR product that provides full response to large frequency deviations in under one second. A key feature of this service is that it requires continuous active power and includes a narrow frequency response trigger of ± 0.015 Hz. However, the service specification only requires that 5% of full response be delivered for small frequency deviations, leaving 95% of enabled capacity available to respond to larger system disturbances outside of the frequency range ± 0.2 Hz.[97] This specification is shown below in Figure 9. Other elements of this service are:[98]

- The service will be enabled by National Grid in response to supplier tenders for fast responding reserves. As part of a phased implementation, initially only low frequency response will be enabled (similar to raise FCAS in the NEM). National Grid plans to extend the service implementation in 2021 to include high frequency response.

94 The Mandatory PFR arrangement is described in section 5.1.2.

95 The Commission's views on enduring PFR arrangements are set out in chapter 5.

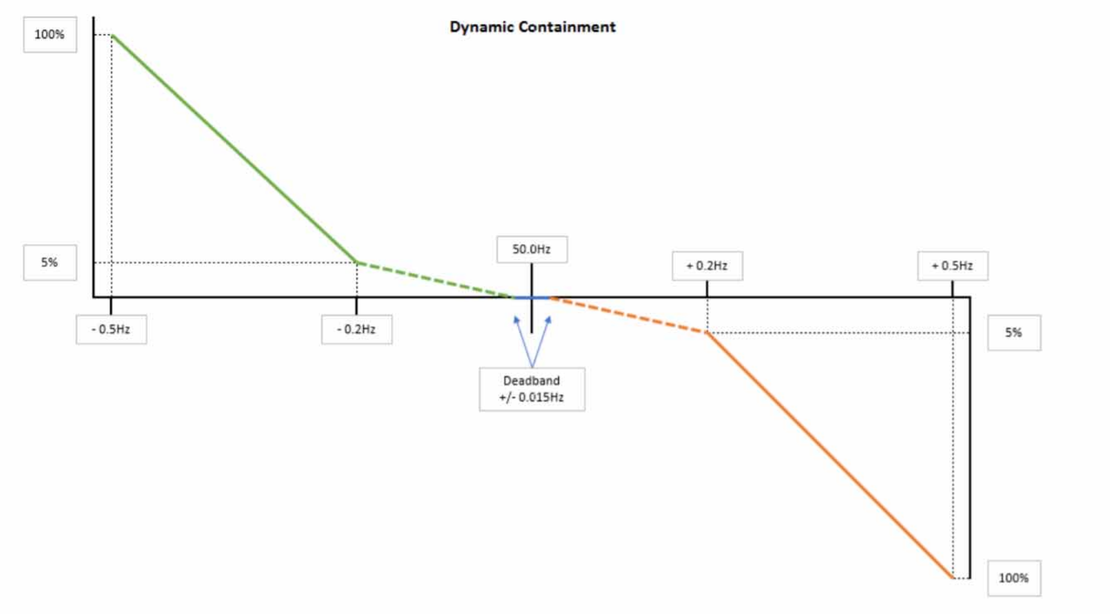
96 National Grid, Service specification for a 'dynamic containment' product.

97 UK National Grid, *Dynamic containment – service terms*, 28 September 2020, paragraph 6.7, p.5.

98 UK National Grid, DC soft launch webinar slides, 18 August 2020. Accessed on 10 November 2020 at: https://www.nationalgrideso.com/industry-information/balancing-services/frequency-response-services/dynamic-containment?market-information

- Service providers will be enabled for delivery throughout a 24-hour period 23:00 – 23:00.

Figure 4.9: UK National Grid - Dynamic containment service specification



Source: UK National Grid, *EBGL Article 26: Proposal for Defining and Using Specific Products for balancing energy and balancing capacity*, 28 October 2020, p.3. – accessed on 10 November 2020 at: https://www.nationalgrideso.com/industry-information/codes/european-network-codes-old/meetings/consultation-open-ebgl-article-26

The National Grid approach allows for the dynamic containment (FFR) service to contribute to frequency regulation during normal operation, while maintaining most of the fast responding capacity as reserve to manage large contingency events. This approach is similar to AEMO's current operational practice of allowing different droop settings under the MASS and the primary frequency response requirements.[99]

Further FFR considerations will need to also consider how such an FFR arrangement would coordinate effectively and efficiently with any enduring mandatory PFR requirement, as well as the effect that the provision of FFR to a narrow band could have on the role of regulating FCAS to correct small frequency deviations.

QUESTION 8: INTERACTION BETWEEN MANDATORY PFR & FFR ARRANGEMENTS

What are stakeholders' views in relation to the potential interactions between new FFR arrangements and the Mandatory PFR arrangement?

99 The allowance for variable droop between mandatory PFR and contingency FCAS response is described in section 5.4.1.

4.8.4 Implementation and staging

Given that it is considered it is appropriate for FFR services to be provided through spot market arrangements in a similar manner to the existing FCAS market arrangements, it is necessary to consider the process for the implementation of market arrangements for FFR and whether there is any need for transitional arrangements to support the implementation process.

Process for the implementation of FFR

Any implementation arrangements would need to accommodate the following steps and processes post any rule being made:

- AEMO to consult on revisions to the MASS to include arrangements for FFR
- AEMO to revise its market dispatch systems, including the development and implementation of constraints for FFR
- AEMO to revise its settlement systems for payment and allocation of costs

Transitional arrangements

In addition to the procedural steps required to implement a new FFR arrangement, there may be a role for transitional arrangements to facilitate the necessary learning and development required for the safe and efficient integration of this new technology. In its submission to the consultation paper AEMO noted that:[100]

> This would allow the power system impacts to be managed. It would also allow some flexibility in refining how the service is best utilised and integrated with the possibility of transitioning to a 5-minute spot market.

AEMO has identified the following issues of concern that require further investigation and operational experience in relation to FFR:[101]

> - FFR injects power quickly into the power grid and there may be locational maximum quantities; and
> - specification for FFR for system intact, as well as its interaction with FCAS products and volumes (constraints), inertia and potentially inertia services, as well as regional frequency management are likely to benefit from progressive refinement based on experience in using and procuring FFR.

AEMO's advice*, FFR Implementation options report*, to provide further information on the challenges and costs associated with implementing an FFR arrangement in the NEM and potential measures for addressing these challenges and mitigating the associated risks.

100 AEMO, Submission to the *Consultation paper – System services rule changes*, 13 August 2020, pp. 18 – 20.

101 Ibid.

QUESTION 9: IMPLEMENTATION AND STAGING FOR FFR

In relation to the discussion of the implementation arrangements for FFR services as set out in section 4.8.4:

- What are stakeholders' views in relation to the process for the implementation of FFR arrangements in the NEM?
- What are stakeholders' views on the potential need for interim or transitional arrangements as part of the transition to spot market arrangements for FFR?

5 PRIMARY FREQUENCY RESPONSE INCENTIVE ARRANGEMENTS

This chapter sets out the initial views on the process and policy options for implementing enduring arrangements to support the efficient and effective provision of Primary frequency response (PFR) services in the NEM. This discussion relates to AEMO's *PFR incentive arrangements* rule change request which is described in section 1.6.

This work follows on from and directly relates to the interim PFR arrangements put in place through the *Mandatory primary frequency response rule 2020 (Mandatory PFR rule)* which commenced in June 2020 and is currently being implemented by AEMO*.* The final rule included provisions for the Mandatory PFR arrangements to sunset after a period of three years on 4 June 2023. As set out in the final determination for that rule, the Commission is committed to the development of alternative or complementary incentive based arrangements for PFR prior to the sunset for the *Mandatory PFR rule*. Further detail on the policy options and pathways towards enduring PFR arrangements are provided below.

5.1 What is primary frequency response and its technical characteristics?

This section describes the technical characteristics of primary frequency response (PFR). It also outlines the Mandatory PFR arrangements that are in the process of being implemented and discusses the potential role for a Mandatory PFR arrangement as part of enduring arrangements for PFR.

5.1.1 What is PFR?

As described in section 2.1, PFR provides the initial response to frequency disturbances. It reacts quickly and automatically to locally detected changes in system frequency in accordance with agreed parameters. PFR can be provided by the automatic modification of generator output or customer demand.

Continuous primary frequency control helps to control system frequency during normal operation by responding to small frequency variations.

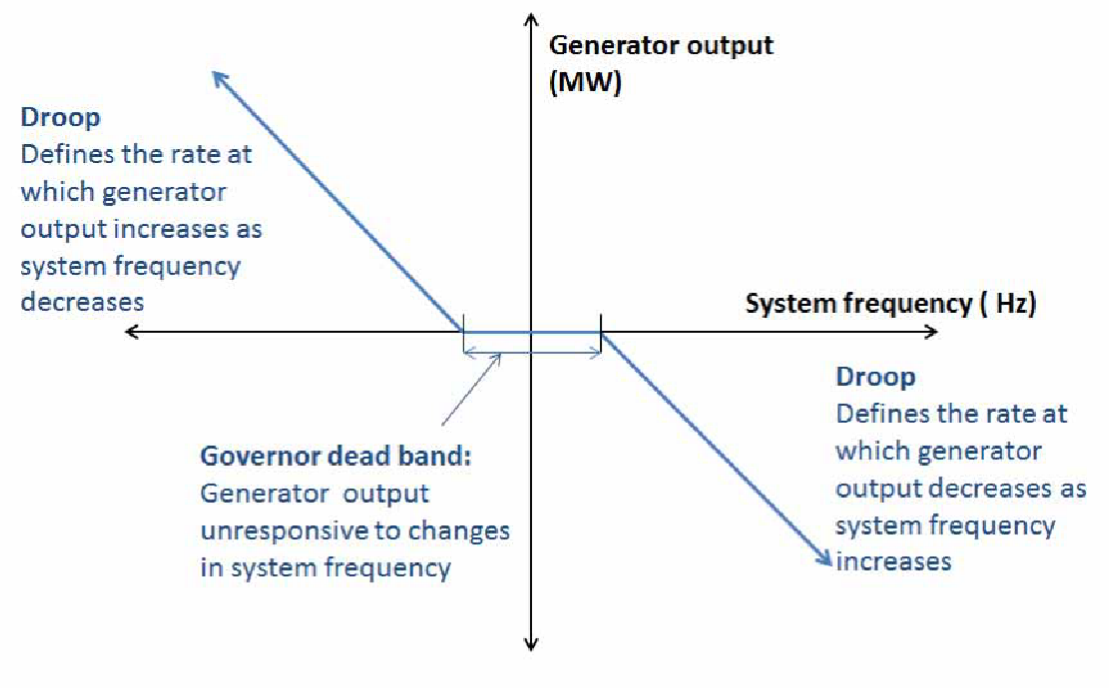
Primary frequency control can also be configured to provide active power response only following larger disturbance events, this is referred to as **contingency response**.

Figure 5.1 shows two key features of PFR, droop & deadband.

- The **deadband** specifies the frequency range within which the governor is unresponsive to power system frequency changes, and within which the power output from the generator is kept steady.
- **Droop** is an indication of the change in generator output for a given change in power system frequency. Given a fall in power system frequency, the droop setting refers to the percentage frequency change that will result in the generator increasing its output by 100 per cent of its rated capacity. For example given a 100 MW generator with a droop

setting of 5 per cent and assuming that the generator is operating with sufficient headroom, a fall in power system frequency of 0.05 Hz or (0.1 per cent of 50 Hz) will result in an increase of power output from the generator of 2MW. Similarly, following an increase of power system frequency of 0.05 Hz the same generator would decrease its power output by 2MW.

Figure 5.1: Primary frequency 'droop' response



Source: AEMC

PFR is only one element of an integrated approach to power system frequency control. Further description of concepts related to power system frequency control is included in section 2.1

5.1.2 Mandatory primary frequency response rule change

The Commission made the *Mandatory PFR rule* on 26 March 2020 in response to rule change requests submitted by AEMO and Dr Sokolowski. Each of the rule change requests proposed the introduction of a Mandatory obligation for Generators in the NEM to be responsive to frequency variations outside a narrow range of insensitivity close to 50Hz. This followed earlier consideration of the issues by the Commission in its *frequency control frameworks review.*

BOX 2: CONSIDERATION OF DEGRADED FREQUENCY CONTROL IN FREQUENCY CONTROL FRAMEWORKS REVIEW.

The Commission considered the issue of degraded frequency control during normal operation in detail through the *2018 Frequency control frameworks review*. Through this process it was recognised that there are risks and costs associated with the power system operating more often at frequencies at the edges of the NOFB. In its 2017 report for AEMO, DigSILENT identified these risks as including:

- increased wear and tear on plant due to excessive movement caused by frequency deviations
- reduction in the efficiency of generators due to changes in output as result of deteriorating frequency regulation and governor response
- reduction in system security for contingencies that result in significant changes in transfer across inter-connectors
- potential need for additional contingency FCAS to maintain the same level of system security given increased variability of system frequency
- increase in regulating FCAS costs
- possibility of further withdrawal of PFR due to the added burden on existing PFR

The key findings of the review included the Commission's conclusion that frequency performance under normal operating conditions have been deteriorating in recent times, primarily as a result of generators decreasing or removing their responsiveness to minor frequency deviations. In response the Commission recommended that:

in the long term, market participants should be incentivised to provide a sufficient quantity of primary regulating services to support good frequency performance during normal operation.

The Commission's work on primary frequency control, has been guided by this recommendation.

Source: DigSILENT, Review of frequency control performance in the NEM under normal operating conditions, final report, 19 September 2017. AEMC, Frequency Control Frameworks Review - Final Report, 26 July 2018, p.viii.

AEMO's rule change request - Mandatory PFR

AEMO's *Mandatory PFR* rule change request was informed by the findings from its investigation of the power system separation event that occurred on 25 August 2018 and expert advice provided by Dr John Undrill.[102] In its rule change, AEMO made the case that the decline in frequency control in the power system had reached the point where AEMO was increasingly unable to control the system frequency under normal operating conditions, due to reduced provision of PFR from generation.

102 On 25 August 2018, lightning struck transmission lines that form the QNI inter-connector between the Queensland and New South Wales regions, the resulting power system disturbance lead to the disconnection of the Qld and SA regions from the interconnected NSW-Vic system. Further information is available in AEMO's Final Report – Queensland and South Australia system separation on 25 August 2018, published 10 January 2019.

AEMO considered that the available tools could not effectively control frequency on an ongoing basis, and that this was increasingly resulting in power system outcomes that AEMO regarded as inconsistent with prudent industry practice. AEMO outlined the following implications due to the degraded frequency control in the power system:

- AEMO's difficulty in meeting the requirements of the Frequency operating standard.
- Ongoing frequency instability in the power system, typified by persistent long period oscillations in NEM frequency, involving all machines across the power system speeding up or slowing down in unison with each other.
- The risk of unexpected power system impacts following increasingly complex power system events
- The increased reliance on load shedding for frequency control following large contingency events
- AEMO's reduced ability to learn from otherwise comparable international power systems.
- The reduction in the predictability of power system behaviour

AEMO considered that there was an immediate need for additional frequency response to restore effective frequency control in the NEM to maintain the safety and security of the power system.

The Commission's determination — Mandatory PFR rule

The Mandatory PFR rule was made on 26 March 2020, in line with AEMO's advice that there was an immediate need for improved frequency control in the national electricity system during normal operation and following contingency events.[103]

The *Mandatory PFR rule* introduced an obligation for all scheduled and semi-scheduled generators, who have received a dispatch instruction to generate to a volume greater than 0 MW in the NEM to support the secure operation of the power system by responding automatically to small changes in power system frequency.[104] This requirement was intended to provide improved frequency control in the NEM during normal operation and following contingency events, resulting in a more resilient power system.

The performance parameters for the mandatory PFR are set out by AEMO in the *Primary frequency response requirements*. In setting the performance parameters (which may be specific to different types of plant), AEMO must define the maximum allowable dead band which must not be narrower than the Primary frequency control band (PFCB).[105] The PFCB is defined in the NER as the range of 49.985 Hz to 50.015 Hz or such other range as specified by the Reliability Panel in the FOS. This governance arrangement recognises the implications of the mandatory frequency response band for both system operation, as well as the operation of the markets for electricity and ancillary services in the NEM.

In its final determination, the Commission noted that a mandatory requirement for PFR on its own is not a complete solution and may not be sufficient to meet the operational needs of

103 AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, pp.26-28.

104 NER Cl 4.4.2(c1)

105 NER Cl 4.4.2A(b)

the power system now and into the future. The Commission recognised that the mandatory approach would ideally be replaced or complemented by market or incentive based arrangements for PFR. To inform the development of such arrangements, the Commission considered that further work needed to be done to understand the power system requirements for maintaining good frequency control.[106]

Many stakeholders also expressed support for the development of market or incentive based mechanisms for PFR.[107] However, given the time needed to develop such arrangements, the Commission considered that it was not possible to implement incentive or market based arrangements at the same time as addressing the immediate system security needs identified by AEMO.

To reflect the interim nature of the mandatory arrangement on its own, the final rule included provisions for the Mandatory PFR requirement to sunset after three years on 4 June 2023.

Costs and benefits of mandatory PFR

As set out in the final determination for the Mandatory PFR rule, the Commission recognises that a mandatory PFR arrangement provides a range of system security benefits including:

- Increased system resilience to significant non-credible contingency events

  A mandatory PFR arrangement complements the response of procured contingency reserves and provide a safety net to provide any additional available generation capacity to respond to contingency events that are larger than a single credible contingency event. This reduces the reliance on emergency frequency control schemes such as under-frequency load shedding and over-frequency generation shedding and provides an additional layer of system resilience.[108]

- Improved frequency control during normal operation (where the frequency response band is set close to 50Hz)

  Primary frequency response and secondary frequency response are fundamentally different and not interchangeable, and that both are vital to the effective management of frequency.[109] PFR is required during normal operation to help control power system frequency.

- Improved ability for AEMO to model and predict power system behaviour.

  The mandatory PFR arrangement provides AEMO with increased certainty around how generation plant will behave following power system disturbances. This supports the accurate modelling of the power system to simulate and confirm power system security following potential contingency events.[110]

106 AEMC, *Mandatory primary frequency response — final determination*, 26 March 2020, p.24

107 Submissions to the *PFR rule changes — consultation paper*, 19 September 2019: CS Energy, p. 2, Delta Electricity, p. 6, Neoen p. 1, Enel X, p. 8, IES, p.2, Enel GreenPower, p. 2, ARENA, p.3.

108 AEMO, *Mandatory primary frequency response — Electricity rule change proposal*, 16 August 2019, p.58.

109 AEMO, *Response to request for advice — Frequency control frameworks review*, 5 March 2018, pp. 6-9.

110 AEMO, *Mandatory primary frequency response — Electricity rule change proposal*, 16 August 2019, p.25.

However, the mandatory PFR arrangement is also expected to impose costs and inefficiencies on power system plant and the operation of the NEM. These include:

- Increased operating costs due to inefficient allocation of responsive plant
- Distortion of frequency related market signals due to:
  - passing the cost of primary frequency response through the energy market, which does not reveal the extent of these costs to the market and places the costs directly on consumers rather than recovering the costs through the FCAS markets
  - passing on costs of narrow band PFR through contingency FCAS markets, which are then amalgamated with the costs of contingency reserves and smeared across all generators. This avoids the performance-based cost allocation of the causer pays process for regulation costs. Generators are therefore not exposed to the full costs of managing system frequency through causer pays and thereby have little incentive to minimise any adverse impacts on frequency.

5.1.3 The role of Mandatory PFR

As noted above, the mandatory PFR requirement, is not a complete solution on its own. However, some form of mandatory PFR arrangement is likely to provide a valuable safety net to help protect the power system from significant non-credible contingency events. If a mandatory requirement of some form is to be maintained, then the challenge will be to realise the security benefits while limiting any associated economic inefficiencies.

Mandatory PFR frequency response band options

In its rule change request, *Mandatory primary frequency response*, AEMO considered three settings for the Mandatory PFR dead band:

- A **narrow** setting with a dead band close to 50Hz ± 0mHz.
- A **moderate** setting with a dead band close to the NOFB of 49.85 Hz to 50.15 Hz (50Hz ± 150 mHz)
- A **wide** setting with a dead band close to 50Hz ± 500 mHz

Ultimately, AEMO's rule change request, *Mandatory Primary frequency response*, and the advice of its consultant, John Undrill, favoured a narrow frequency dead band setting close to 50Hz ± 0mHz and this informed the initial setting of the PFCB in the Mandatory PFR rule. The PFCB sets a lower bound on the dead band to which individual generators must comply with the requirements of AEMO's PFR specification, the *Primary frequency response requirements*. The PFCB was set at a narrow range of 49.985 Hz to 50.015 Hz, in line with advice from AEMO.

The Commission, based on AEMO's advice, considered that a **narrow** mandatory frequency response band would:[111]

111 AEMO, *Mandatory primary frequency response* — Electricity rule change proposal, 16 August 2019, p.46.

- Result in the most stable control of frequency under normal operating conditions and would reduce the amplitude of the observed ongoing oscillations in NEM frequency to the lowest practicable level.
- Maximise the resilience of the NEM to frequency disturbances by minimising the frequency deviation caused by any given power system disturbance, which would provide the best opportunity for maintaining stable operation of the power system.

In contrast, AEMO considered a **moderate** mandatory frequency response band as a potentially viable parameter for the mandatory PFR, noting that this would go some way to improving the resilience and predictability of power system performance as all generation that is potentially capable of providing PFR would be required to respond following a significant power system disturbance. However, AEMO noted that a moderate PFR response band was not consistent with international practice for power system operation and would have no impact on the effective control of frequency under normal operating conditions. To improve frequency performance AEMO would have been reliant on adjusting parameters with respect to the small number of other mechanisms available, such as the arrangements for the procurement and coordination of regulation and contingency FCAS.[112]

Similarly, AEMO considered that, under a **wide** frequency response band, the effectiveness of the mandatory PFR arrangement at improving system resilience would be muted due to the late operation of the PFR safety net following contingency events. Such an arrangement may also have the perverse outcome of reducing the PFR provided by generation in response to all but the most extreme disturbances. This is due to the possibility that generators that currently provide PFR at or near the NOFB may change their response bands to the wider mandatory setting. This could reduce the aggregate generation response to contingency events and make it more difficult to recover from power system disturbances.[113]

QUESTION 10: THE ROLE OF MANDATORY PFR

In relation to the discussion of the role for mandatory obligation as part of the enduring PFR arrangements in the NEM, set out in section 5.1.3:

- Do stakeholders agree that a mandatory PFR arrangement provides a valuable safety net to help protect the power system from significant non-credible contingency events?
- Do stakeholders agree that the narrow, moderate and wide settings for a mandatory PFR response band, adequately represent the broad policy options for the frequency response band for Mandatory PFR?

5.2 The Rule change request

This section outlines the problem statement and solution proposed by AEMO in its rule change request.

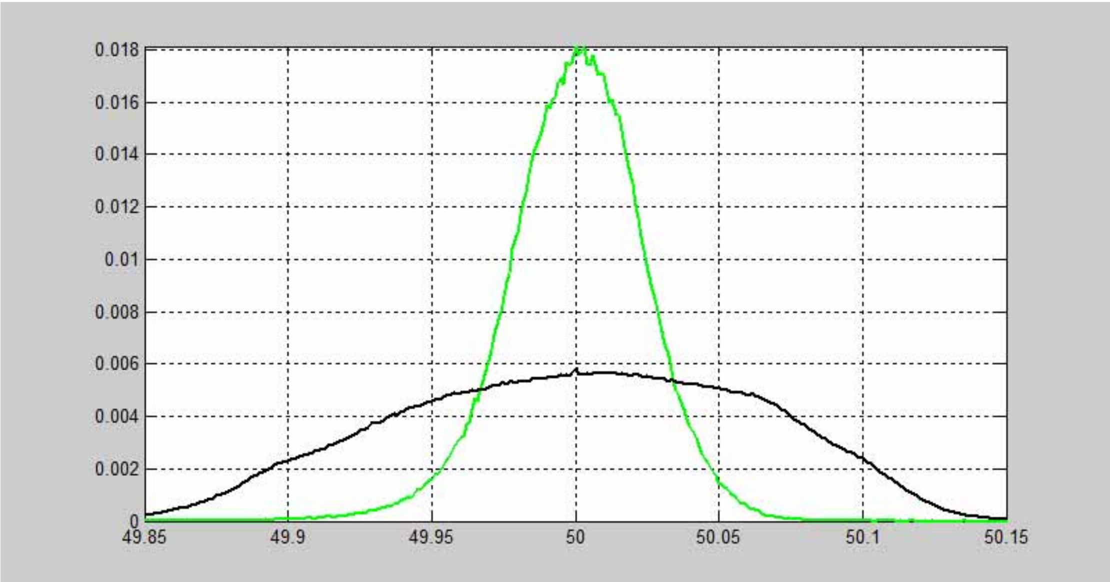
112 Ibid., p.49.
113 Ibid., p.48.

5.2.1 Problem statement

The fundamental problem identified in AEMO's rule change request is the degradation of frequency performance in the NEM under normal operating conditions over the five-year period 2015 to 2019.[114]

AEMO claims that the degradation of frequency performance during normal operation has resulted in the power system frequency spending more time further away from the target frequency of 50Hz than had historically been the case. This is shown by a flattening of the frequency distribution in the power system as seen in Figure 5.2.

Figure 5.2: Frequency distribution within the normal frequency operating band in the NEM2005 snapshot v. 2018 snapshot



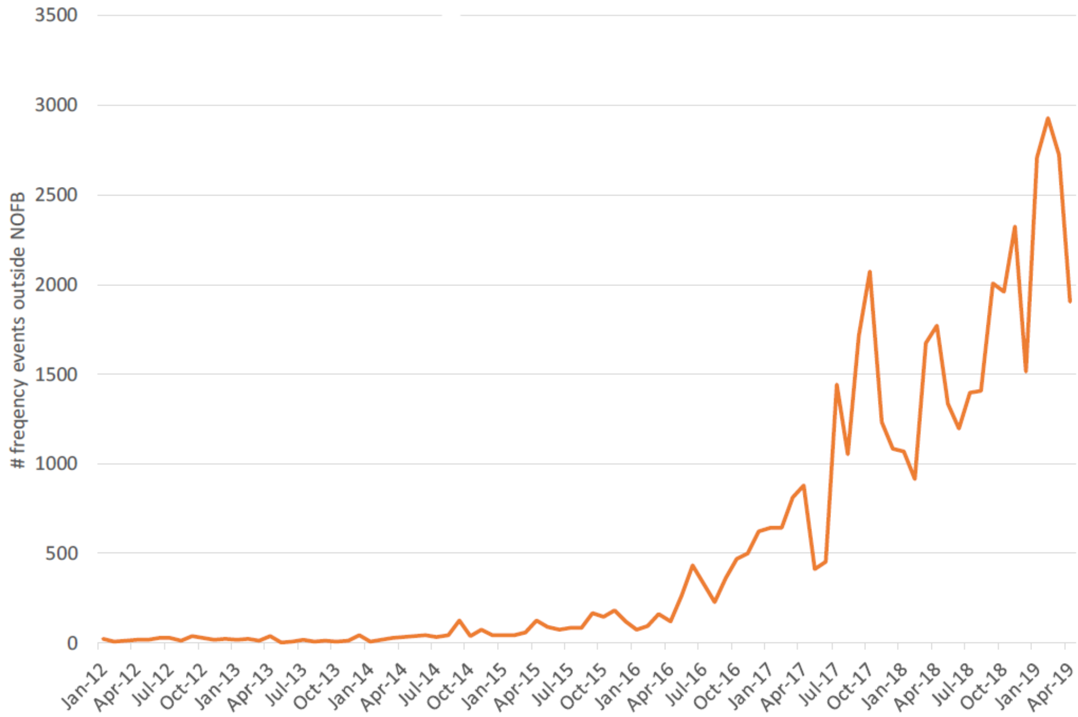
Source: AEMO, Primary frequency response incentive arrangements— Electricity rule change proposal, 1 July 2019, p.14
Note: X-axis: Frequency (Hz)
Note: the green line shows 2005 data, the blackline shows 2018 data.

AEMO has also reported an increased incidence of exceedance events, where the power system frequency falls outside the normal operating frequency band (NOFB), as shown in Figure 5.3.[115] Many of these excursions have occurred under normal operating conditions in the absence of a contingency event.

114 AEMO, *Rule change proposal - Primary frequency response incentive arrangements*, 3 July 2019, pp.14.

115 The frequency operating standard requires that, in the absence of contingency events, the power system frequency is maintained within the normal operating frequency band (49.85 Hz to 50.15 Hz) for 99% of the time. The frequency may exceed the normal operating frequency band for 1% of the time, but, in the absence of a contingency event, it must not exceed the normal operating frequency excursion band, 49.75 – 50.25Hz.

Figure 5.3: Frequency excursions outside the normal operating frequency band



Source: AEMO, *Rule change proposal - Primary frequency response incentive arrangements*, 3 July 2019, pp.46.

AEMO identified the degradation of frequency performance during normal operation as being caused by:

- a decline in the provision of PFR by Generators, exacerbated by elements of the NER
- an increase in the variability of generation and load in the power system
- the inappropriateness of secondary regulation services to effectively control system frequency in the absence of PFR.[116]

5.2.2 Proposed solution

Through consultation with market participants, AEMO identified the following aspects of the NER as being perceived to provide disincentives to the voluntary provision of PFR:[117]

- Certain aspects of the arrangements for the allocation of costs associated with regulation services, known as 'causer pays'. (NER Clause 3.15.6A)
- A focus by generators on prioritising strict compliance with dispatch instructions over operating their plant in a frequency response mode and providing PFR. (NER Clause 4.9.8)

116 AEMO, *Primary frequency response incentive arrangements*— Electricity rule change proposal, 1 July 2019, p.16.
117 AEMO, *Rule change proposal - Primary frequency response incentive arrangements*, 3 July 2019, pp.14 – 25.

- A perception that the NER requires generators to provide PFR only when they are enabled to provide a Frequency control ancillary service (FCAS). (NER Cl 4.9.4 & Cl S5.2.5.11).

AEMO's proposed rule sought to address these perceived disincentives in the NER to remove barriers to the provision of voluntary PFR during normal operation and halt the decline of frequency performance during normal operation.

Issues addressed in the Mandatory PFR rule

The *Mandatory primary frequency response rule 2020 (Mandatory PFR rule)* included changes to NER clause 3.15.6A, cl 4.9.4, cl 4.9.8 and cl S5.2.5.11 to clearly acknowledge that it is expected and acceptable for generation output to vary from dispatch targets when providing PFR.

AEMO's rule change proposed further changes to clause 3.15.6A such that providers of PFR, in accordance with parameters defined by AEMO, would not be allocated any share of regulation costs.[118] This proposal was not addressed by the Mandatory PFR rule. Rather, the Commission noted that further changes to the NER in relation to the causer pays arrangements would be considered through the assessment of the *Primary frequency response incentive arrangements rule change.*[119]

5.3 Stakeholder views

This section provides a summary of stakeholder views expressed in response to the two consultation papers that discussed issues related to the *PFR incentives rule change*:

- *Primary frequency response rule changes* – Consultation paper, 19 September 2019
- *System services rule changes* – Consultation paper, 2 July 2020

The Commission has also received two additional submissions outside of the consultation periods for the above papers.

5.3.1 Summary of relevant submissions to the consultation papers

The Commission is aware of a wide range of stakeholder views in relation to the arrangements for PFR in the NEM. Representatives from transmission networks along with power system engineers and AEMO have advocated for mandatory PFR and the associated benefits from broad based active power control.[120] At the same time many stakeholders have expressed concern that the proposed mandatory PFR requirement was unlikely to be the most efficient option for valuing primary frequency response in the long-term. These stakeholders reasoned that incentive or market-based arrangements to provide PFR would likely be more efficient and effective over the longer term.[121] Stakeholders highlighted a

118 AEMO, P*rimary frequency response incentive arrangements*— Electricity rule change proposal, 1 July 2019, p.27.

119 AEMC, Mandatory primary frequency response — Rule determination, 26 March 2020, p.127.

120 Submissions on the Consultation paper - *PFR rule changes,* 19 September 2019: AEMO, p.1.; Ergon Energy and Energex, p1; Kate Summers, p.2; TasNetworks, p.3.

121 Submissions to the consultation paper – *PFR rule changes*, 19 September 2019: CS Energy, p. 2, Delta Electricity, p. 6, Neoen p. 1, Enel X, p. 8, IES, p.2, Enel Green Power, p. 2, ARENA, p.3.

number of concerns with the existing frameworks which they believe could be efficiently addressed through an incentive-based mechanism for PFR, including:

- PFR should be valued to reflect the costs to generators of providing the service
- Generators should be incentivised to maintain headroom if a PFR mechanism is to be technically effective
- PFR should be procured at economically efficient levels
- Appropriate economic signals should exist for investment and innovation

The costs of providing PFR

Many stakeholders considered that the costs of providing PFR are not insubstantial and vary for individual generators. Stakeholders argued that mandating PFR provision without valuing PFR based on the different costs incurred by generators to provide PFR distorts competition in the energy markets and so PFR should be appropriately valued.

CS Energy, Stanwell and Delta Electricity identified that thermal generators experience costs related to thermal inefficiencies, where fuel usage increases to maintain stored energy for PFR provision.[122] Delta Electricity quantified the cost of maintaining 10% headroom for a coal unit:[123]

> The 10% stored energy is known to equate to about 0.9% additional coal consumption. Based on nominal conditions and present coal tonnage costs, this equates to about $1M p.a. per 660MW unit.

Tilt Renewables claimed that it expects that the ongoing costs incurred by semi-scheduled generators will be greater than those incurred by scheduled generators as semi-scheduled generators typically operate at full output with no headroom and so will mostly provide lower PFR, resulting in lost energy revenue. Tilt Renewables estimated the loss of energy generation due to the mandatory PFR requirement will:[124]

> ..likely to be in excess of 1% of NEM generation revenues, assuming the current frequency performance in the NEM.

Headroom must be valued for a PFR mechanism to be effective

Without mandatory headroom, or an incentive for generators to preserve headroom, stakeholders suggested that the mandatory requirement for PFR may not result in effective frequency control.

Energy Australia, for one, did not believe AEMO will be able to rely on the provision of PFR under the Mandatory PFR rule as AEMO cannot be certain of the amount of headroom generators are voluntarily providing.[125] Furthermore, due to the costs of preserving

122 Submissions to the consultation paper – *PFR rule changes*, 19 September 2019: CS Energy, p. 9, Delta Electricity, p. 32, Stanwell p. 6.

123 Delta Electricity, Submission to the consultation paper – *PFR rule changes,* 19 September 2019, pp. 32-33.

124 Submissions to the consultation paper – *PFR rule changes*, 19 September 2019: Infigen, p. 2, Enel X, pp. 3-6, Stanwell p. 4.

125 Energy Australia, Submission to the consultation paper – *PFR rule changes*, 19 September 2019, pp. 7.

additional headroom for frequency control, as discussed above, many stakeholders considered that the mandatory requirement for PFR will incentivise generators not to retain headroom or de-commit, unless enabled for FCAS.[126] Stanwell was supportive of this view and considered that, under the proposed mandatory requirement, PFR will only be provided by generators enabled for contingency FCAS or which preserve headroom for fast ramping capabilities.[127] Some stakeholders considered that the loss of voluntary headroom under the mandatory PFR requirement will result in less PFR being provided than if the rule were not made.

Some stakeholders were also concerned that a narrow band PFR requirement will result in the headroom that is preserved by generators being utilised for control within the NOFB and therefore not being available for contingency response.[128] Enel Green Power also made the point that variable renewable energy generation (VRE) do not typically have headroom to provide raise PFR, yet the penetration of VRE is continuing to increase.[129] Stakeholders considered that an effective frequency control mechanism would incentivise the preservation of headroom for PFR, as summarised by the AEC: [130]

> Confidence in frequency response can only come about if the PFR is supported by a known quantity of stored energy. In turn, this can only come about through dispatched, compensated provision, ideally co-optimised with the energy markets similarly to the existing FCAS markets.

Economically efficient levels of PFR

Many stakeholders do not believe that all generators need to provide PFR for effective frequency control and to obligate all to do so would result in an oversupply of PFR, the inefficient costs of which would be borne by consumers. Some stakeholders have suggested that the required volume of PFR may be much less than a near universal provision:

- Tesla pointed to the UK's Enhanced Frequency Response service to which the National Grid (UK ISO) attributed significant economic benefits from the procurement of 200MW of frequency response services.[131]
- ARENA considered the required volume of PFR to meet system needs is likely to be similar to current regulation FCAS volumes.[132]
- Stanwell argued that AEMO observed a clear improvement in system frequency performance following the PFR trials in Tasmania where approximately 30% of generators had reduced or removed dead bands. Stanwell recognised the Tasmanian power system

126 Submissions to the consultation paper – *PFR rule changes*, 19 September 2019: ERM Power, p. 8, Delta Electricity, p. 5, AEC, p. 6, Infigen, p. 7

127 Stanwell, Submission to the consultation paper – *PFR rule changes*, 19 September 2019, p. 5.

128 Submissions to the consultation paper – *PFR rule changes*, 19 September 2019: Powershop, p. 4, AEC, p. 6, Infigen, p. 7.

129 Enel Green Power, Submission to the consultation paper – *PFR rule changes*, 19 September 2019, pp. 1-2.

130 AEC, Submission to the consultation paper – *PFR rule changes*, 19 September 2019, p. 7.

131 Tesla, Submission to the consultation paper – *PFR rule changes*, 19 September 2019, p. 4.

132 ARENA, Submission to the consultation paper – *PFR rule changes*, 19 September 2019, p. 2.

is different to the mainland power system but believes the trials provide evidence that universal PFR is not required.[133]

In their responses to the consultation paper, ERM Power, Delta Electricity and Energy Australia suggested that an effective mechanism for frequency control should be assessed by its ability to meet the FOS, as defined by the Reliability Panel. Designing a mechanism to meet requirements beyond the FOS raises questions as to whether the level of PFR being procured is necessary and cost-efficient.[134]

Appropriate economic signals for investment and innovation

A majority of stakeholders commented on the need for economic signals to encourage investment and innovation in frequency control provision, including investment in batteries, FFR provision and demand-side response from distribution energy resources (DER) and virtual power plants (VPPs). These stakeholders suggest that the mandatory requirement for PFR does not properly value faster frequency control or other frequency services and distorts the FCAS markets, potentially leading to a higher cost for consumers over the long term.[135]

Stakeholders such as Delta Electricity, Infigen and AGL agreed with the point made in the AEMC's consultation paper that the mandatory PFR requirement will lead to increased supply into the contingency FCAS markets, putting downwards pressure on contingency FCAS prices.[136] ARENA, Powershop, AGL and Hydro Tasmania also expect that the mandatory requirement will reduce the need for regulation frequency control and therefore undermine the price signals in the regulation FCAS markets as well.[137] However, AEMO considered the impact of additional PFR provision on the regulation FCAS markets would be minimal.[138] ARENA noted that decreased FCAS prices would result in reduced costs to consumers in the short-term.[139]

Most stakeholders were concerned that the lack of economic signals for frequency control services will increase the costs of frequency control over time. The two main reasons for this sentiment are:

- There may be an under supply of PFR and other frequency control services without sufficient investment by new entrants, especially as thermal generators retire.[140]
- The proposed arrangements will not incentivise innovation and investment in more cost-effective frequency control technologies.[141]

133 Stanwell Submission to the consultation paper – *PFR rule changes*, 19 September 2019, pp. 4-5

134 Submissions to the first consultation paper - *Primary frequency response incentive arrangements*, 19 September 2019: ERM Power, p. 2, Delta Electricity, p. 6, Energy Australia, p. 2.

135 Submissions to the consultation paper – *PFR rule changes*: Tesla, pp.6-9, Tilt Renewables, p.1, Energy Australia, p.6, Origin, p.2, IES, p.2.

136 Submissions to the consultation paper – *PFR rule changes*: Delta Electricity, p. 2, Infigen p. 2, AGL, p.4.

137 Submissions to the consultation paper: Hydro Tasmania, p. 2, ARENA, p. 2, AGL, p.4, Powershop, p.2.

138 AEMO, *Primary frequency response incentive arrangements - Electricity rule change proposal,* 1 July 2019, p. 43.

139 ARENA, Submission to the PFR rule changes consultation paper, 1 November 2019, p.2.

140 Submissions to the consultation paper: ERM Power, p. 8, Alinta, pp. 2-3, Stanwell, p. 4, Neoen, p. 5, Enel X, pp. 6-7

141 Submissions to the consultation paper: Energy Australia, p. 6, Origin, p. 2, Neoen, pp. 1-4.

5.3.2 CS Energy/IES – Double sided causer pays report

On 30 June 2020, the AEMC received a further submission from CS Energy in relation to the *PFR incentives rule change*. This submission included a report commissioned by CS Energy and produced by Intelligent Energy Systems that set out the findings from a project that produced a prototype system to calculate the costs of primary frequency response in real-time. As noted in the report:[142]

> The aim of this project has been to demonstrate a workable and viable means to incentivise the provision of PFR in a commercial manner.
>
> […]
>
> This project implements a version of deviation pricing stripped down to deal specifically with primary frequency control and closely aligned to the approach used in regulation causer pays.

The IES report outlines a design approach and implementation considerations for a deviation pricing system based on the procedure for allocation of regulation FCAS costs, Causer pays. Under the IES approach, participant performance is measured with respect to the MW equivalence of the proportional frequency deviation.[143] The IES paper describes and demonstrates a methodology to measure market participant contributions to frequency deviations as a basis for payments for provision of PFR and allocation of costs to market participants that contribute to frequency deviations.

In the deviation pricing process, market participants whose units acted to help control system frequency would be paid relative to their positive contribution factors, determined through the causer pays process. The costs of these payments would be allocated to participants who are assessed to have contributed to deviations in system frequency. Deviation quantities would be calculated based on the difference between the metered quantity of generation or demand with respect to the target set-point based on the unit dispatch target. The price associated with deviations would then be applied to the deviation quantities to determine deviation settlement amounts.

Further description and discussion of frequency response deviation pricing and the similar process of double-sided causer pays is included below in section 5.6.2.

The report is available on the AEMC project page.[144]

5.3.3 AEC proposal – PFR pathways

On 22 September 2020, the AEMC received a supplementary submission from the Australian Energy Council (AEC) in relation to the development of enduring PFR arrangements through the *PFR incentives rule change.* This submission outlined the findings from an options assessment undertaken by the AEC's Frequency Control Sub-Group focused on developing a pathway towards enduring PFR arrangements in the NEM.

142 CS Energy/IES, Submission to the Primary frequency response incentive arrangements rule change, 30 June 2020, p.v

143 CS Energy/IES, Submission to the Primary frequency response incentive arrangements rule change, 30 June 2020, p.2.

144 See: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

The AEC recognised that the deterioration of system frequency in recent years required corrective action, however:[145]

> the AEC does not consider that the current rule – unrewarded mandatory PFR from all capable plant to a near-zero deadband – is sustainable in the long-term. That rule sunsets in June 2023 and should be seen as purely an emergency measure. In the meantime, the industry must find a long-term economically sustainable PFR mechanism.

The AEC Frequency Control Sub-Group assessed the range of potential policy mechanisms identified through the 2018 *Frequency control frameworks review* and determined two equally ranked preferred pathways towards enduring PFR arrangements. [146]The pros and cons of each of the potential PFR procurement options were considered and evaluated against the following assessment criteria:[147]

- Economic efficiency;
- Practicality of implementation; and
- Power System Security confidence, from the perspective of the System Operator

The AEC's PFR pathways start from the existing Mandatory PFR arrangements and incorporate a transitional period before the existing mandatory arrangement is revised and replaced with a long-term arrangement that provides economic signals to guide plant investment and performance. The AEC proposes that the transitional arrangements commence at least one year prior to the sunset for the Mandatory PFR rule and that the long-term arrangements apply following the sunset date, 4 June 2023.[148]

The AEC's shortlisted enduring procurement arrangements for PFR during normal operation are:

- **PFR FCAS** (aka Primary regulating service) - Narrow band PFR based on FCAS market enablement. The AEC describe the key features of this arrangement as:[149]
  - The Reliability Panel, under advice from AEMO, would determine a new NOFB Frequency Operating Standard, and the Rules would establish an enablement market for NOFB PFR analogous in design to the existing FCAS contingency services.
  - The additional resources procured under this market would respond to small variations in system frequency to help maintain the frequency close to 50 Hz in the absence of contingency events.
  - The MASS would specify the service specification for the new primary regulating services.

145 AEC, Supplementary submission to the *Primary frequency response incentive arrangements rule change,* 22 September 2020, p.2.

146 A summary of the PFR policy options considered previously by the AEMC is included in section 5.6.

147 AEC, Supplementary submission to the *Primary frequency response incentive arrangements rule change,* 22 September 2020, p.2.

148 Ibid.

149 Ibid., p.7.

    - Providers would register their PFR capability and submit bids to AEMO of their available PFR reserves (effectively headroom in MW). AEMO would dispatch sufficient PFR service through NEMDE to meet the new NOFB standard.
- **Double sided causer pays** (DSCP) - Voluntary provision of PFR in response to a dynamic incentive price derived from the existing Causer pays process for allocation of regulation costs. The key features of the proposed double-sided causer pays approach are :[150]
    - Deviations from linear dispatch targets are calculated every four seconds for each market participant generating unit.
    - Those participants whose deviations from dispatch are making the frequency worse are levied a penalty which is used to pay those participants whose deviations from dispatch are making the frequency better.[151]
    - As with the existing causer pays, the payment quantities are a product of the deviation and frequency error (including some pricing function). The transaction would be resolved for each four second time interval, i.e. there would be no 28 day averaging or notice period, as is the case under the existing causer pays process.

The AEC's proposed PFR pathways are outlined below:[152]

Table 5.1: **AEC's proposed PFR pathways**

STAGE	PATHWAY A: PFR FREQUENCY CONTROL ANCILLARY SERVICE (FCAS)	PATHWAY B DOUBLE-SIDED CAUSER-PAYS (DSCP)
Initial mandatory stage	• Continued mandatory provision of near-zero dead band PFR without stored energy; and • A new raise and lower PFR FCAS, designed as per existing FCAS markets, with enabled providers supporting their narrow-band PFR response with stored energy.	• Continued mandatory provision of near-zero dead band PFR without stored energy; and • Implementation of the Double sided causer pays mechanism
Long-term design		

150 Ibid., p.7.

151 noting that the goal of frequency control is for the system frequency to be maintained at or close to the nominal frequency of 50.0 Hz.

152 Ibid. pp.2-3.

STAGE	PATHWAY A: PFR FREQUENCY CONTROL ANCILLARY SERVICE (FCAS)	PATHWAY B DOUBLE-SIDED CAUSER-PAYS (DSCP)
	• Continued mandatory provision of wide-band PFR without stored energy to provide a system security safety-net for non-credible power system events. • A raise and lower PFR Frequency Control Ancillary Service (FCAS), designed as per existing FCAS markets, with enabled providers providing narrow-band PFR response supported with stored energy	• Continued mandatory provision of wide-band PFR without stored energy to provide a system security safety-net for non-credible power system events. • Operation of the Double-sided causer pays mechanism to provide a natural incentive to deliver dis-aggregated narrow-band PFR with stored energy.

Source: AEC, Supplementary submission to the *Primary frequency response incentive arrangements rule change,* 22 September 2020, p.2.

One common element of both pathways is that the arrangements for valuation of PFR during normal operation would be supported by a revised mandatory PFR obligation set at a wider frequency response setting of ± 0.50Hz to assist in saving the system from extreme non-credible contingency events.[153]

The AEC recognises the value in further analysis and modelling on the technical feasibility of a double-sided causer pays approach to reward provision of PFR during normal operation. To address this, the AEC is looking to coordinate further work to understand the workings of a double-sided causer pays system along with the potential operational and market impacts. This work will be progressed by IES, in collaboration with ARENA, with the advice delivered in early 2021.[154]

The AEC did not express a preference between its two PFR pathways. However, it noted that the findings of the Double-sided causer pays advice may influence its final position.

5.4 Analysis of the problem

The following points define the problem related to the arrangements for PFR in the NEM:

153 Ibid. p.26.

154 Ibid. p.3.

- Continuous narrow band PFR is required to complement secondary (regulation) services and control power system frequency during normal operation.[155]
- A mandatory PFR arrangement provides a safety net to help stabilise the power system following significant non-credible contingency events.[156]
- In the absence of any further change to the NER, the Mandatory PFR arrangement will cease from 4 June 2023 and the NER will not require provision of PFR outside of that enabled through the market ancillary service arrangements for contingency reserves.
- The mandatory PFR arrangement on its own is not a complete PFR solution since it does not value the provision of frequency response provided outside of that enabled through the market ancillary service arrangements for regulation and contingency reserves. The Commission considers that this under-valuation of PFR does not support efficient allocation of resources in the NEM and weakens the signals for efficient investment in power system plant to meet future power system needs.
- Therefore, there is a need to develop an arrangement for PFR that will endure beyond the sunset date for the Mandatory PFR arrangement to meet the operational needs of the power system and support economic operation and investment in the NEM.

Solutions to this will be addressed and progressed through the ESB's work, of which these rule changes are a part. This will likely include the following actions:

1. Confirm the **regulatory arrangements** and the role of Mandatory PFR

   This includes consideration of whether or not the Mandatory PFR arrangement should continue beyond the sunset date or be revised as part of an enduring PFR arrangement. The role of mandatory PFR is discussed in section 5.1.3 and this discussion is extended in section 5.7.

2. Develop **procurement arrangements** for new market ancillary services as required to automatically respond to small frequency deviations in the power system.

   Depending on the Mandatory PFR arrangement, there may be a need to develop complementary arrangements to procure PFR for small frequency deviations. This is discussed in section 5.6.1.

3. Develop **pricing arrangements** as required to value and pay providers of PFR

   Depending on the procurement arrangements for PFR there may be a need to reform the pricing arrangements for PFR. This is discussed in section 5.6.2.

4. Consideration of the **cost allocation** approach for frequency regulation services

   A discussion of the cost allocation arrangements for PFR during normal operation is included in section 5.6.3.

   A discussion of reforms to the existing arrangements for the allocation of regulation FCAS costs – Causer pays, is included in section 5.9.

155 AEMO, Response to request for advice — Frequency control frameworks review, 5 March 2018, pp.5-6

156 NER clause 4.2.3(e) defines a non-credible contingency as: a contingency event other than a credible contingency event. The definition then describes examples of non-credible contingencies as: three phase electrical faults on the power system; or ... simultaneous disruptive events such as: multiple generating unit failures; or double circuit transmission line failure (such as may be caused by tower collapse).

5. Consider revisions to the **frequency operating standard** in relation to how the required frequency performance for the power system during normal operation is specified.

   The Commission recognises that it may be necessary for the Reliability Panel to review the FOS to reflect the operational objectives for frequency control during normal operation, this is discussed below in section 5.8.

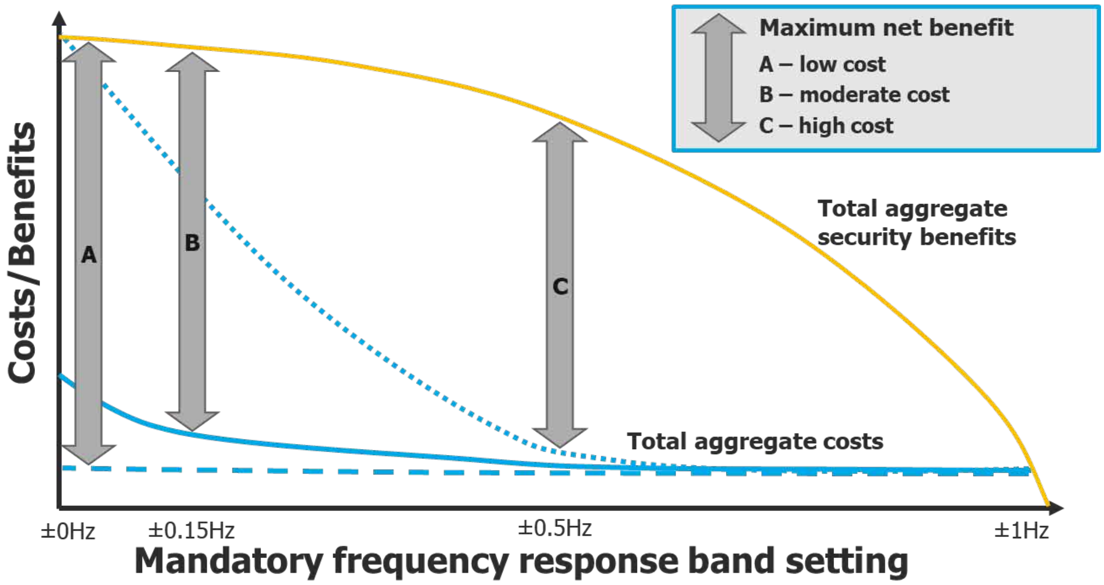
QUESTION 11: PROBLEM DEFINITION AND REFORM OBJECTIVE — PFR INCENTIVE ARRANGEMENTS RULE CHANGE

What are stakeholders' views on the problem definition and reform objectives for enduring PFR arrangements set out in section 5.4?

5.4.1 Economic analysis of mandatory PFR

The ongoing security benefits of a mandatory requirement are likely to be greater with a narrower response band. However, it is also likely that the ongoing aggregate market and system costs associated with mandatory frequency response would be increased under an arrangement with a narrow response band versus a wider band. Figure 5.4 provides some example cost curves to illustrate the potential relationship between the security benefit and economic costs for a mandatory PFR arrangement relative to the required frequency response band setting.

Figure 5.4: Mandatory PFR costs and benefits - indicative example



Source: AEMC
Note: Indicative sketch intended to convey concepts for discussion. The conceptual cost and benefit curves are based on the potential aggregate system impacts and assume near universal application of a common mandatory PFR requirement. The impact on individual plant may vary from the aggregate impact shown.

The yellow line depicts an indicative example of the total aggregate system security benefit associated with a Mandatory PFR arrangement. Moving from right to left it is suggested that the security benefits would initially increase quickly as a mandatory PFR arrangement is introduced within an active range inside 50Hz ± 1 Hz. These benefits would likely include the reduction in unserved energy associated with under-frequency load-shedding that would otherwise act to re-stabilise system frequency following large non-credible contingency events that cause the system frequency to fall below 49.0Hz.

As the frequency response band is narrowed towards 50Hz ± 0Hz, the security benefits would be expected to continue to increase, albeit at a diminishing rate, due to such impacts such as improved active power control and system frequency stability.

The ongoing cost of providing frequency response may also change with different response band settings. Figure 5.4 depicts three different indicative cost curves, reflecting three different scenarios that provide examples for how the costs associated with mandatory PFR may change due to variation of the frequency response trigger band.[157] The three cost curve scenarios are:

- **low cost** - under this scenario the costs associated with mandatory PFR are flat and do not change to any significant degree due to a variation in the frequency response band.

157 These scenarios account for the potential market impacts associated with the interaction of a Mandatory PFR arrangement with the contingency FCAS markets in the range outside of the NOFB and the regulation markets inside the NOFB.

- **moderate cost** - under this scenario the costs associated with mandatory PFR increase as the frequency response band is narrowed. While the rate of increase is initially gentle the incremental costs increases more rapidly for narrower frequency response settings close to 50Hz ± 0Hz.
- **high cost** - under this scenario the costs associated mandatory PFR increase rapidly as the frequency response band is narrowed below 50Hz ± 0.5Hz..

Under each scenario, the net benefit is depicted by the vertical distance between the yellow benefit curve and the blue cost curve. Under the 'low cost' scenario, the indicative net benefit is assumed to be maximised close to 50Hz, with the indicative net benefits under the other two scenarios are assumed to be maximised at progressively wider deadband response settings.

The Commission will consider the conceptual framework outlined here in the determination of the enduring PFR arrangements and is interested in stakeholders' views on this. In particular the Commission seeks evidence from stakeholder submissions along with the advice from AEMO and the independent consultant that would help inform which of the cost scenarios described above is most realistic. This will inform how an enduring PFR arrangement can be developed to maximise the net social benefit in the long-term interests of consumers.

Frequency response band is not the only variable, other policy settings impact the shape of the aggregate cost curve. Other important factors include the proportion of the fleet that is required to be responsive to frequency deviations and the strength of the active power response required. For example, the exemptions framework in the Mandatory PFR rule acts to effectively remove high cost plant from the mandatory PFR obligation. Similarly, the operation of parallel market arrangements for PFR may act to flatten the overall system cost curve by preferentially enabling low cost providers of frequency response with the duty of being responsive to small frequency variations.

Another example of a detailed policy setting that can be configured to reduce the cost impact associated with mandatory PFR is the variation of the droop requirement for mandatory frequency response, this is discussed below.

Allowance for variable droop settings for Mandatory and FCAS response

The operational impact of the existing mandatory PFR requirement is somewhat mitigated by AEMO allowing different droop requirements for frequency response to small deviations versus the performance requirements for contingency response under the MASS.[158] The PFRR requires a droop setting of less than 5% and allows generators to apply different droop settings for different size frequency deviations.[159] The MASS allows more aggressive droop settings for provision of contingency FCAS. AEMO currently allows a minimum (most aggressive) droop setting of 1.7%.[160]

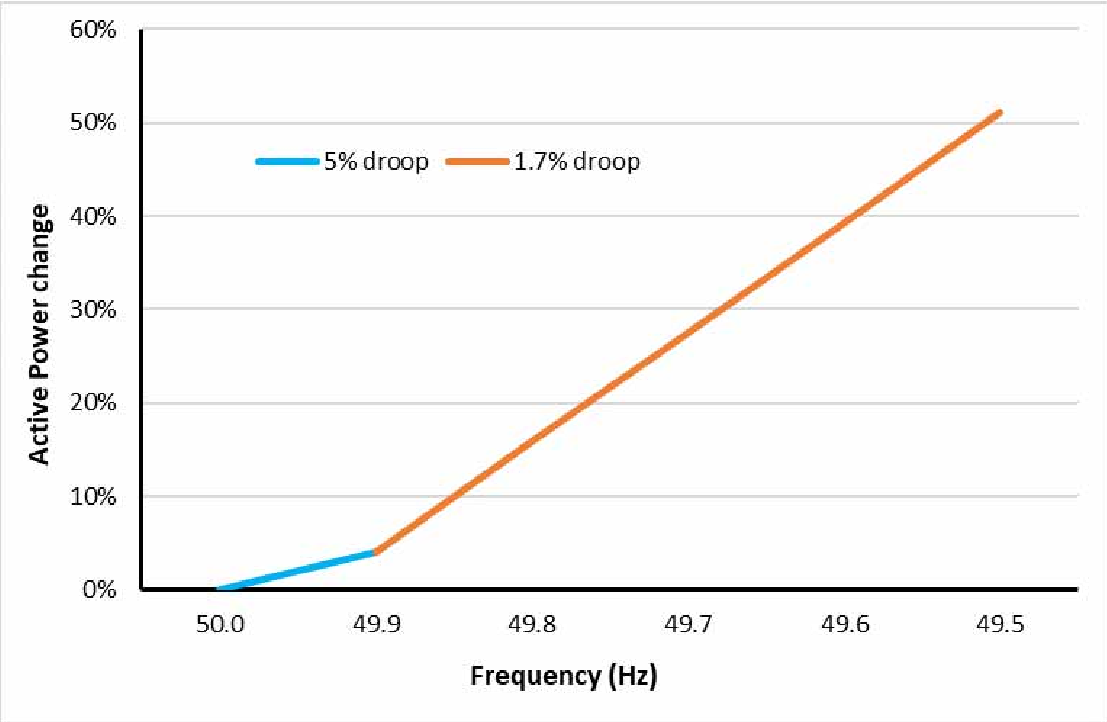
158 The generator droop setting specifies a percentage frequency change that will result in 100% output from the generation plant, therefore a smaller droop setting corresponds to a larger active power response for a given frequency deviation.

159 AEMO, *Interim Primary frequency response requirement*, 4 June 2020, p.7.

160 AEMO, *Battery energy storage requirements for contingency FCAS registration*, 14 January 2019, p.5.

The result of these settings is that the proportional response expected for small deviations may be less aggressive than that for larger frequency deviations. This variable droop concept is illustrated in Figure 5.5. The figure shows a 5% droop response for small variations in frequency down to 49.9Hz, in this case the 0.1Hz frequency variation will result in a 5% change in active power output. A more aggressive droop response of 1.7% applies for frequency deviations beyond 49.9Hz, resulting in a 16% change in active power for a frequency deviation of 49.8Hz or 0.2Hz.

Figure 5.5: Generator variable droop response



Source: AEMC

The impact of the variable droop arrangement is that the generator active power mileage or cumulative variation of power output due to frequency response, may be less significant for the mandatory response to small frequency variation than would otherwise be the case if the more aggressive droop response were required in response to small frequency variations.

With the mandatory PFR arrangement in place and the immediate operational needs for PFR met, the Commission wants to further investigate the viability of widening the PFCB and implementing complementary arrangements to provide sufficient PFR to respond to small frequency deviations during normal operation. As discussed above, AEMO will provide commentary on the viability of this approach as part of its advice to support the assessment of the PFR incentives rule change.

QUESTION 12: ECONOMIC ANALYSIS OF MANDATORY PFR

In relation to the discussion of the costs and benefits of Mandatory PFR arrangements set out in section 5.4.1:

- What are stakeholders' views of the example curves for costs and benefits of Mandatory PFR with respect to the frequency response band settings, set out in figure 5.4?
- Do stakeholders agree that the frequency response band setting is a key variable for the determination of enduring PFR arrangements that meet the power system needs and are economically efficient over the long term?
- What are stakeholders' views on the effectiveness of the exemption framework under the Mandatory PFR arrangement?
- What are stakeholders' views on the role that the allowance for variable droop settings plays in relation to the cost impacts of Mandatory PFR?
- Based on the initial roll out of the Mandatory PFR arrangement to generators over 200MW, what are stakeholders' views on how the cost impacts of Mandatory PFR are impacted by the proportion of the fleet that is responsive to frequency variations?
- What other considerations are there in relation to developing effective and efficient arrangements for PFR in the NEM?

5.5 Advice

The Commission's determination of enduring PFR arrangements will be informed by technical advice from AEMO and independent advice on the relative costs and benefits of each of the pathways for enduring PFR arrangements.

These pieces of advice are described in more detail below.

5.5.1 AEMO's PFR incentivisation feasibility report

AEMO has committed to providing technical advice to inform the development of enduring PFR arrangements for the NEM.[161] This advice, *PFR incentivisation feasibility report,* will outline AEMO's views on the technical feasibility of the policy options identified in this directions paper for enduring PFR arrangements. The report will be informed by AEMO's learnings associated with the roll out of changes to generation plant control settings consistent with the *Mandatory PFR rule*, including the associated monitoring of the materiality of impacts on generation plant and the relationship with power system frequency performance.

AEMO's advice will also describe the adequacy of the existing frequency control arrangements, including the mandatory arrangement and the arrangements for the procurement of frequency responsive reserves. This will include AEMO's views as to whether

161 AEMO, Frequency Control Work Plan, 25 September 2020, p.10.

additional measures are required to satisfy the future needs of the power system, as well as any costs of additional mechanisms.

Finally, AEMO's views are sought on the design of the enduring market and regulatory arrangements for frequency control in the NEM, including the role of Mandatory PFR and the operational feasibility and practicality of additional complementary arrangements. Views on the policy options and pathways to enduring PFR arrangements as described in section 5.6 and section 5.7 of this paper will be sought.

AEMO's advice will be an important input into the draft determination for the *PFR Incentives rule change* which will set out the Commission's determination of the appropriate enduring PFR arrangements and seek stakeholder feedback.

AEMO has informed the AEMC that the scope of its advice will include:

- **Implementation and monitoring of Mandatory PFR**

  AEMO will provide a summary of learnings associated with the roll out of the Mandatory PFR arrangement including analysis and commentary of related cost impacts and the effectiveness of the Mandatory PFR arrangement, as explained below.

  Cost impacts

  - Qualitative analysis on the materiality of plant impacts associated with provision of narrow band PFR.
  - Commentary on the impact of Mandatory PFR on governor movement/mileage for responsive generation.

  Effectiveness

  - AEMO's estimate of the responsive portion of the generation fleet for the mainland NEM and Tasmania under the Mandatory PFR arrangement and how this relates to the responsive portion prior to implementation of the mandatory PFR.
- **Enduring PFR pathways**

  With reference to the enduring PFR pathways defined in this paper, AEMO will provide advice covering:

  - AEMO's view on the adequacy of the frequency control frameworks out to 2035. In particular, whether AEMO considers that the NER provide adequate tools for it to coordinate sufficient frequency responsive reserves to control frequency during normal operation and following credible contingency events.
  - Consideration of the operational viability of setting the primary frequency control band (PFCB) within the following three general ranges:
    - Narrow – close to the existing PFCB of 49.985 Hz to 50.015 Hz or 50Hz ± 15 mHz
    - Moderate – close to the NOFB of 49.85 Hz to 50.15 Hz or 50Hz ± 150 mHz
    - Wide – close to the range 49.5 Hz to 50.5 Hz or 50Hz ± 500 mHz[162]

162 This range is the same as the containment band for a generation or load event that applies to operation of the mainland NEM for an interconnected system.

- Consideration of the quantity and location of reserves required for each of the frequency control services, under the following market design scenarios
  - — Existing FCAS markets with narrow mandatory PFR
  - — Existing FCAS markets plus raise and lower primary regulating services with moderate or wide mandatory PFR
- High level consideration of the feasibility of implementing a new primary regulation service to respond to small frequency deviations in tandem with transitioning the Mandatory PFR requirement from the current narrow setting towards a moderate or wide setting.
- High level consideration of alternative options to incentivise provision of PFR for small frequency deviations.
- Consideration of the feasibility of changes to the procedure for the allocation of regulation costs to better align this procedure with PFR provision and/or incentivise PFR, including the proposed valuation of positive contribution factors, referred to as double sided causer pays.
- Consideration of how the mandatory PFR requirement applies to small generation plant, bi-directional plant and loads, including DER, batteries and plant aggregated through virtual power plant arrangements.[163]
- Estimated cost for implementation of each of the enduring PFR pathways.

5.5.2 Independent advice

The Commission notes the wide range of views expressed by stakeholders in relation to the market and regulatory arrangements for PFR in the NEM. These views are summarised in section 5.3. In recognition of the divergence of views in relation to the role of mandatory arrangements for PFR, the Commission intends to seek independent advice in conjunction with AEMO as an additional input into its draft determination for the *PFR incentive arrangements rule change.* This independent advice will complement the advice to be provided by AEMO through the *PFR incentivisation feasibility report.*

This independent advice will be facilitated by AEMO through access to relevant data and information associated with the implementation of the Mandatory PFR arrangements, which it commenced in 2020 and is continuing into the first half of 2021.

The preliminary questions that the Commission is likely to seek independent advice on include:

1. What is the level of collective effort required from responsive power system plant to achieve differing levels of system performance?
2. What is the impact on individual plant from participating in narrow band PFR relative to system frequency performance?

163 The existing mandatory PFR arrangement applies to scheduled and semi-scheduled generators, which effectively limits its application to generators with capacity greater than 30MW. On 8 October 2020, the AEMC initiated two rule change requests relating to Generator registration thresholds. These rule change requests propose to reduce the threshold for classifying generators as non-scheduled from 30MW nameplate capacity to 5MW, making the default classifications for generators above 5MW scheduled (or semi-scheduled).

3. Are there any practical considerations around individual plant capabilities and limitations in providing continuous PFR?

We are interested in any stakeholder views on these matters.

> QUESTION 13: ADVICE FOR ENDURING PFR ARRANGEMENTS
>
> What are stakeholders' views of the Commission's proposed approach to obtaining independent advice to inform its determination of enduring arrangements for PFR in the NEM?

5.6 Policy options

The Commission notes that a number of alternative arrangements for PFR have been previously identified and considered through the *Frequency control frameworks review* and the assessment of the *Mandatory PFR rule change*. These policy options are summarised below in Table 1, with further detail below.

Table 5.2: **Summary of PFR policy options**

REF	DESCRIPTION	SUMMARY NOTES
A	Narrow band PFR provided by regulating FCAS.	Under such an arrangement, a generator that is enabled to provide a regulating service would respond to both a change in locally measured frequency and to signals from AEMO's AGC system. Not considered further in this paper (see further discussion below).
B	Narrow band PFR provided by contingency FCAS	Under this option, the trigger points for some or all of the existing contingency services would be narrowed through changes to the frequency operating standard and/or the market ancillary service specification. Section 5.6.1 describes potential procurement arrangements for PFR services including the role of the existing FCAS arrangements.
C	Mandatory PFR – (in place until 4 June 2023)	A mandatory requirement could be placed on market participants for the provision of PFR. Section 5.1.3 describes the potential enduring role for a mandatory PFR arrangement.
D	Structured – contract procurement	The contract procurement of PFR would involve the specification of performance characteristics and the required quantity of service by AEMO. These services would then be procured on a periodic

REF	DESCRIPTION	SUMMARY NOTES
		contract basis by AEMO or potentially a TNSP as is the case for other non-market ancillary services such as network support and control ancillary services (NSCAS) and system restart ancillary services (SRAS). Not considered further in this paper (see further discussion below).
E	New market ancillary service – Primary regulating service	New ancillary service markets for PFR could be developed, similar to the existing market ancillary services. This would allow AEMO to prescribe the required amount of each type of service. The provision of these services could then be dynamically optimised in response to changing market and power system conditions. Section 5.6.1 describes potential procurement arrangements for PFR services including the potential role of new market ancillary service arrangements.
F	Performance based PFR incentives – using regulation FCAS contribution factors (double-sided causer pays)	These options are different forms of incentive pricing arrangements for the provision of PFR. Further detail on each of these potential pricing arrangements is provided in Section 5.6.2.
G	Performance based PFR incentives – measured separately to regulation FCAS factors (frequency response deviation pricing)	
H	Regulated pricing for PFR	

Source: AEMC

Option A – Narrow band PFR provided by regulating FCAS – was previously determined to not be a viable mechanism for provision of PFR due to associated challenges for system and market operation identified in relation to the provision of primary and secondary frequency control through a single ancillary service.[164] This option is not considered further in this paper.

Option D – structured/contract procurement – is not a preferred part of an enduring PFR arrangement for the NEM either. While this was considered as a potential interim arrangement in place of mandatory PFR, the provision of frequency control services is best achieved through a competitive dispatch process, similar to the existing market ancillary

164 AEMC, Frequency control frameworks review — Final report, 26 July 2018, pp. 121-123.

services. This view is consistent with, and is supported by, the market design principles set out in the NER and the direction of the ESB.[165] Therefore, this option is not considered further in this paper.

The following sections discuss how each of the remaining policy options may form part of the enduring arrangements for PFR in the NEM.

- Section 5.6.1 describes potential procurement arrangements for PFR services including
  - The existing FCAS arrangements (option B)
  - New market ancillary service arrangements (option E)
  - Voluntary provision of narrow band PFR
- Section 5.6.2 describes potential pricing arrangements for PFR including
  - Pricing through competitive dispatch via the market ancillary service arrangements (option B & E)
  - Pricing using regulation FCAS contribution factors (double-sided causer pays) (option F)
  - Pricing through a separate measure of plant frequency response (frequency response deviation pricing) (Option G)
  - Regulated pricing for PFR (Option H)
- Section 5.6.3 describes potential arrangements for allocation of costs associated with new pricing arrangements for PFR.

5.6.1 Procurement of narrow band PFR

The costs and market inefficiencies associated with the existing Mandatory PFR arrangement could be further reduced by widening the PFCB and putting in place complementary arrangements to provide response to small frequency deviations and support frequency control during normal operation.

There may be a need for new and additional procurement arrangements to provide sufficient PFR to help control system frequency during normal operation. This is particularly the case for an enduring arrangement that includes a widening or removal of the mandatory PFR requirement. There are three main options for procurement of narrow band PFR, they are:

- **Option 1 – Existing market ancillary service arrangements** used to enable reserves for narrow band PFR (no change to existing market arrangements)
- **Option 2 – New market ancillary service arrangements** for enablement of primary regulating services (as per option E from Table 5.2)
- **Option 3 – Voluntary incentive-based provision** of primary regulating services in response to new pricing arrangements to reward response to small frequency deviations during normal operation (as per options F, G & H from table 5.2).

These options are described below:

165 NER cl 3.1.4 (a) (6); Energy Security Board, *System services and ahead markets*, April 2020, pp.19-20.

Option 1- Existing market ancillary service arrangements

The existing market ancillary service arrangements include provisions for AEMO to coordinate the scheduling and dispatch of the following eight services through a competitive bid process for each 5-minute dispatch interval:

- The two raise and lower regulation services
- The six raise and lower contingency service (fast, slow and delayed)

The *Mandatory PFR Rule 2020*, requires all scheduled and semi-scheduled generation plant to respond to small variations in power system frequency, but it does not require plant to maintain stored energy to provide PFR. As a result, the procurement of any required energy reserves would occur through the existing market ancillary service arrangements. In effect, the procurement of contingency reserves also provides reserves for PFR to help control system frequency during normal operation.

AEMO will provide advice on the adequacy of these arrangements out to 2035 to support effective frequency control during normal operation and following credible contingency events in order to inform our considerations.

Option 2 – New market ancillary service arrangements for primary regulation services

It may be preferable for new market ancillary service arrangements to be introduced to support the enablement of facilities to provide narrow band PFR, separate to the existing regulating and contingency services.

Conceptually, the new market ancillary service arrangements would include separate raise and lower categories for primary regulation services. These services would act in combination with the existing secondary regulation services to respond to normal variations in power system frequency in accordance with the requirements of the FOS for normal operation.

The preliminary view is that the need for new market ancillary service arrangements for narrow band PFR would be less under the narrow mandatory PFR regime. This is because, a mandatory narrow band PFR regime does not differentiate between response to small frequency deviations associated with normal operation and larger frequency deviations associated with contingency events. However, when combined with the widening of the PFCB or the removal of the existing mandatory PFR arrangement, new arrangements for primary regulating services are likely to have the following benefits:

- Market participants may bid to provide narrow band PFR and express their willingness to do so through their service bids
- AEMO would specify the performance requirements for the primary regulating service and determine the required volume of the service to meet the operational needs of the power system
- The volume of primary regulating service could be co-optimised with that of the secondary regulating service, enabling improved operational efficiency
- The market framework would clarify the role of the contingency services as being for the provision of reserves to respond to contingency events. As such these services would not

be required to respond to small frequency deviations, although they may be incentivised to do so on a voluntary basis through the MASS or otherwise.[166]

- This arrangement would also create a more consistent and level playing field for providers of proportional and switched response through the contingency FCAS arrangements.[167]

The combination of a moderate or wide PFCB and the enablement of narrow band PFR through market ancillary service arrangements is likely to provide AEMO with operational certainty in relation to how generation plant will respond to variations in power system frequency. This was a key requirement identified by AEMO in its rule change request, *Mandatory primary frequency response.*[168]

Option 3 – Voluntary incentive-based provision

An alternative to the development of new market ancillary service arrangements for PFR during normal operation is the voluntary provision of PFR in response to incentives provided through improved pricing arrangements. This option could operate alongside or in the absence of a Mandatory PFR arrangement. A Mandatory PFR arrangement would provide increased certainty for system operation, if required, at the expense of plant operational flexibility.

Under this option there would not be any centralised procurement of reserve volumes for provision of narrow band PFR, rather the volume of service provided would be determined by market participants in response to the incentive pricing arrangements. While AEMO would not have direct control of the PFR service volume, it is feasible that AEMO may have some control over the pricing arrangements for PFR in order that it may influence the frequency performance outcomes during normal operation.

The following section includes a description of potential pricing reforms that could be implemented to improve the incentives for the provision of PFR.

QUESTION 14: PROCUREMENT ARRANGEMENTS FOR NARROW BAND PFR SERVICES

In relation to the discussion of potential procurement arrangements for narrow band PFR services in section 5.6.1:

- What are stakeholders' views on three options identified for further consideration?

166 The Commission notes that version 6.0 of AEMO's *Market ancillary service specification* values contingency response provided inside the NOFB from the Contingency event time. It is conceivable that the mandatory PFR requirement could be relaxed to allow a wider setting for mandatory PFR response, while the MASS could value and reward active power response provided from a narrow frequency response trigger. Ref. AEMO, *Market ancillary service specification Version 6.0, 1 July 2020, p.31.*

167 The trigger settings switched response under the MASS range from 49.80 Hz – 49.60 Hz for raise services and 50.20 Hz to 50.40 Hz for lower services. This is in contrast with the requirement that proportional response from generation commence no later than when the system frequency reaches the edge of the normal operating frequency band (49.85 Hz – 50.15Hz) and the requirement under the mandatory PFR rule that generators be responsive to frequency outside of the narrow deadband as approved by AEMO through the *Primary frequency response requirements. Ref. AEMO, Market ancillary service specification Version 6.0, 1 July 2020, p.14, 29.*

168 *AEMO, Mandatory primary frequency response — Electricity rule change proposal, 16 August 2019, pp.25-26.*

a. Existing market ancillary service arrangements
b. New market ancillary service arrangements
c. New incentive-based arrangements for voluntary provision

- Are there any other options that would be preferable?

5.6.2 Pricing

Pricing of PFR service provision is an integral component of enduring and complete arrangements for PFR. This is because it is the pricing arrangements that provide the economic signals to market participants to invest in and operate power system plant in an efficient way to meet system needs and reduce the overall costs of power system operation over the long term.

The existing market ancillary service arrangements provide effective pricing for secondary frequency regulation services and contingency reserves. The element of the frequency control framework that may be under-priced is the provision of narrow band PFR to help control frequency control during normal operation. Some form of pricing reform is likely to be required under each of the potential future roles for Mandatory PFR. However, appropriate pricing arrangements may differ depending on the role of mandatory PFR and the selected PFR procurement model.

The following PFR pricing arrangements have been identified for further consideration through the *PFR Incentive arrangements* rule change.

- Pricing through the competitive dispatch of market ancillary services
- Pricing using regulation FCAS contribution factors - double sided causer pays [169]
- Pricing through a separate measure of plant frequency response
- Regulated pricing for PFR provided outside of the existing FCAS market arrangements[170]

Each of these pricing options is described in further detail below.

Pricing through the dispatch of market ancillary services

This pricing arrangement would apply under an enduring PFR pathway that includes the development of market ancillary services focused on the delivery of narrow band PFR.

These pricing arrangements would operate in a similar way to the existing FCAS market arrangements, in which market participants bid to provide frequency responsive reserves and are enabled through a competitive dispatch process coordinated by AEMO. As for the existing FCAS arrangements, the ancillary service price is determined for each dispatch interval on a

169 Double sided causer pays is a form of deviation pricing that was described by the Commission through the frequency control frameworks review. AEMC, *Frequency control frameworks review – Final report*,26 July 2018, p.90 – 98.

170 Some stakeholders proposed the application of a regulated payment for PFR through the consultation on the Mandatory PFR rule. Submissions to the AEMC consultation paper – PFR rule changes, 19 September 2019: Alinta Energy, p.4; Hydro Tasmania, p.2; Energy Australia, p.2.

regional basis and enabled providers are paid the product of their enabled quantity and the ancillary service price.[171]

Double sided causer pays

The current arrangements for the recovery of the costs of regulating FCAS seeks to allocate those costs to the participants that give rise to the need for the service. A principal objective of the regulating FCAS cost recovery arrangements is to place a financial incentive on market participants to act in a way that minimises the need to procure regulating services. By imposing the costs of the services on those market participants that give rise to the greatest need for the services, there is an incentive for those market participants to minimise adverse impacts to system frequency, and therefore minimise the overall requirements for the services.

However, the strength of this incentive is limited in that it currently only seeks to allocate costs to those participants that cause frequency deviations. It does not reward participants that help to minimise frequency deviations.

The double-sided causer pays approach would reward market participants whose facilities respond to small frequency deviations through valuation of positive contribution factors determined through AEMO's causer pays procedure. The causer pays procedure determines a contribution factor for each market participant facility with four-second metering. This contribution factor is a measure of the average performance of a generator with respect to how closely it follows its dispatch targets and whether any deviation from its dispatch target helps to control system frequency or not.

Stakeholders were generally supportive of the double-sided causer pays approach proposed in the *Frequency control frameworks review*.[172] The AEC also expressed support for a double-sided causer pays mechanism as one of two preferred options for the valuation of PFR through its recent submission to the PFR incentive arrangements rule change.[173] Albeit the AEC proposal would implement a double sided causer pays regime along with a wide setting for the mandatory PFR response band.

A number of participants, including AEMO, Engineers Australia and Neoen have each expressed concern in relation to the potential for adverse consequences under an incentive based PFR regime.[174]

AEMO will provide advice on the operational feasibility of a double-sided causer pays approach to valuation of PFR under each of the enduring pathways for PFR.

Frequency response deviation pricing

171 NER cl.3.15.6A(a)

172 Submission to the AEMC *Frequency control frameworks review - draft report*, 20 March 2018: AEC, p.3; ARENA, p.3; CEC, p.3; CS Energy, p.9-10; Origin Energy, p.1; Snowy Hydro, pp.6-7; Tesla, p.3.

173 AEC, Submission to the second consultation paper for the *Primary Frequency Response Incentive Arrangements rule change,* p.2-3.

174 Submissions to the AEMC *Frequency control frameworks review - draft report*, 20 March 2018: AEMO, pp. 5-6; Engineers Australia; p.7. Neoen, Submission to the second consultation paper for the *Primary Frequency Response Incentive Arrangements rule change, p.2.*

During the *Frequency control frameworks review* the Commission explored the concept of deviation pricing as a model for a transparent performance-based incentive regime to reward market participants that help restore frequency deviations back to the target value of 50Hz. Under this approach, payments made to plant that help to correct frequency deviations would be balanced out by charges levied on market participants whose plant performance contributed to the frequency deviations.

The deviation pricing concept is similar in concept to the existing process for determining participant contribution factors for the allocation of regulation costs. The key differences are the:

- existing causer pays process does not value or reward positive contribution factors
- causer pays process measures plant performance with respect to frequency indicator(FI) rather that a direct measurement against system frequency.[175]
- causer pays process incorporates a temporal disconnect between a market participant's performance and the application of contribution factors to allocate costs to that participant

As described above, a double side causer pays process would value and reward positive contribution factors and bring the causer pays process one step close to a deviation pricing approach.

The remaining difference would be the measure of plant performance with respect to system frequency rather than frequency indicator (FI). FI is a control variable calculated by AEMO's automatic generation control (AGC) system. It includes proportional and integral components, and thus does not always align with the measure of system frequency. FI is a measure of the need for regulation services over time intervals in the order of minutes, it is used within the AGC system as a control variable and it guides the centralised control of the existing regulation services that provide secondary frequency control in response to electronic signals from AEMO. The use of FI as the metric for the causer pays process aligns with the requirement under NER cl. 3.15.6A(k), that the regulation FCAS contribution factor "reflect the extent to which the Market Participant contributed to the need for regulation services;".

While FI may be an appropriate performance mechanism for measuring the need for regulating FCAS, the view that performance measurement with respect to frequency is likely to be a more appropriate in relation to provision of PFR. Measuring plant performance against frequency would improve the transparency around the desired active power response, as frequency is easily measured in real time at any point in the system, whereas FI is only known ex-post following publication of this data by AEMO. Therefore, if a double-sided causer pays arrangement were implemented, it is envisaged that the NER would be revised to reflect the intention that power system plant automatically respond to oppose deviations in frequency away from 50Hz. AEMO considered this issue through its 2018 review of the

175 FI is a parameter used within AEMO's systems to indicate the amount of generation required to be added or removed to restore the frequency to 50 Hz

causer pays procedure, and although it determined to retain FI as the performance measure it noted:[176]

> AEMO acknowledges that using FI as a weighting factor in the long term may not provide the best signal for frequency control, particularly in light of the changing power system and generation mix. Alternative options such as local frequency may provide clearer signals for frequency control, but changes to accommodate local frequency as a weighting factor are more significant.

There are likely to be advantages associated with measuring plant frequency performance with respect to system frequency rather than FI. These advantages include:

- system frequency is readily measured at any point in the power system and is thus a transparent system variable that market participants can respond to in real time
- measurement of plant performance with respect to system frequency will align the economic incentives with the real time operational goal of maintaining system frequency close to 50Hz.[177]

Going forward, we will consider whether any changes to the NER are required to allow for measurement of plant frequency performance with respect to frequency rather than FI.

A key component of the deviation pricing mechanism is the price function that is used to set the price that participants are paid for supporting frequency or are charged for contributing to frequency deviations. The price function sets the economic value of helpful and harmful active power deviations from dispatch with respect to controlling power system frequency. If deviation pricing were to be pursued as part of enduring arrangements for PFR, then further work would be required on the development of the deviation price function.

Regulated pricing for PFR

Regulated pricing for PFR is a potentially simpler alternative arrangement that could respond to the under-pricing of PFR under the mandatory narrow band regime. Under such an approach, a regulated price would be determined by the AER which would provide a top-up payment for providers of PFR who are not enabled to provide frequency response through the market ancillary service arrangements. The regulated pricing regime may also include performance scalars which would apply as price multipliers to reflect the range of value provided by responsive plant, due to plant characteristics, such as speed of response, or the requirement for PFR based on time of day or location in the power system.

A regulated payment regime for PFR provided outside of the market enablement currently operates in the Norwegian electricity system. In Norway, the frequency control frameworks include ancillary service arrangements for frequency containment reserves (FCR), which are

176 AEMO, *Regulation FCAS contribution factor (Causer pays) procedure consultation* – Final report and determination, p.19.

177 The target frequency in the NEM is specified as 50.0Hz. However, there are occasions when AEMO varies the target system frequency, such when performing time error correction. The practise of time error correction involves the modification of this target power system frequency in order to reduce any accumulated time error in accordance with the limits in the FOS for Tasmania and the mainland. To correct a positive accumulated time error, the target frequency is set below 50 Hz, while to correct a negative time error the target frequency is set above 50Hz. The Commission understands that, depending on the size of the accumulated time error, the target frequency may vary between 49.95 and 50.05 Hz.

similar to the FCAS arrangements in the NEM. In the Norwegian market, plant that is not enabled and paid for FCR may still be paid for the provision of power to help control system frequency, referred to as residual supply. This payment is based on a regulated price that is paid to market participants based on plant production data.[178]

A number of stakeholders expressed support for such an arrangement in the NEM through the consultation on the Mandatory PFR rule.[179]

> QUESTION 15: PFR PRICING ARRANGEMENTS
>
> What are stakeholders' views on the arrangements for the pricing of PFR as described in section 5.6.2?

5.6.3 Cost allocation (payment)

The procurement and pricing options discussed above are likely to incur costs associated with payments made to providers of PFR. Therefore, the Commission must also consider appropriate arrangements for the allocation (or payment) of these costs.

The NER market design principles set out that:

> where arrangements require participants to pay a proportion of *AEMO* costs for *ancillary services*, charges should where possible be allocated to provide incentives to lower overall costs of the NEM. Costs unable to be reasonably allocated this way should be apportioned as broadly as possible whilst minimising distortions to production, consumption and investment decisions;

The cost allocation arrangements should be transparent and simple such that market participants can understand how their actions relate to the cost allocation.

Allocation of primary regulation costs through the existing causer pays process

Rather than smear the costs of PFR during normal operation across all market participants or a sub-set of participants, it may be appropriate to incorporate the costs of any new arrangement for pricing narrow band PFR within the existing cost allocation for regulation services. Such an approach would be simpler than adding a new process for the allocation of primary regulation costs, in addition to the existing process for the allocation of [secondary] regulation costs.

While there are some technical differences between the secondary control provided by the existing regulation services and the automatic primary control provided by narrow band PFR, these services act together to control (or regulate) system frequency during normal

178 Statnett, Varsel om vedtak om levering og betaling for systemtjenester 2021, jf. forskrift om systemansvaret i kraftsystemet (fos) § 9, § 15 og § 27 (Notice of decision on delivery and payment for system services 2021, cf. regulations on the system responsibility of the power system (fos) § 9, § 15 and § 27), 14 October 2020, p.6.

179 Submissions on the AEMC *Frequency control frameworks* review - consultation paper: Alinta Energy, p.4; Hydro Tasmania, p.2; Energy Australia, p.2.

operation. Therefore, it is likely to be appropriate that the costs of both services are allocated in proportion to the degree to which a market participant contributes to the small frequency deviations during normal operation.

Combining the cost allocation process for primary and secondary regulation services will also avoid an outcome that increases the complexity of the existing cost allocation process.

> QUESTION 16: ALLOCATION OF COSTS FOR NARROW BAND PFR
>
> What are stakeholder's views on the allocation of costs for narrow band PFR services as described in section 5.6.3?
>
> Do stakeholders agree that the any additional costs for narrow band PFR be allocated through the existing causer pays procedure for the allocation of regulation costs (or a revised version as described in section 5.9?

5.7 Pathways for enduring PFR arrangements

Building on the analysis of potential policy options for the procurement, pricing and payment for PFR services, set out in section 5.6, the Commission has identified three viable pathways towards enduring PFR arrangements. These three pathways are defined by three different settings for the PFCB and related frequency response bands for mandatory PFR.

In summary, the three pathways to enduring PFR are:

1. Maintain the existing Mandatory PFR arrangement with improved PFR pricing
2. Revise the Mandatory PFR arrangement by widening the PFCB and develop new FCAS arrangements for the provision of PFR during normal operation - (Primary regulating services)
3. Remove the Mandatory PFR arrangement and replace it with alternative arrangements for PFR

The Commission notes that a double-sided causer-pays or deviation pricing approach could operate alongside any setting for the mandatory PFR arrangement. On the other hand, the implementation of a new primary regulating service for continuous PFR is likely to require some broadening of the frequency response band for mandatory PFR.

Subject to the receipt of technical advice as discussed in section 5.5, the initial position is that pathway two is likely to provide a balance between providing operational certainty and system resilience while also incorporating new market arrangements that are likely to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of electricity consumers. The arrangements under pathway two incorporate elements of both mandatory and market-based procurement, albeit for different types of PFR. While further detailed policy development is required, this hybrid approach provides AEMO with additional operational tools and is likely to provide greater flexibility to future power system developments.

Accordingly, the initial view is that pathway three is not preferred given that a mandatory PFR arrangement provides a valuable safety net against the potential impacts associated with significant non-credible contingency events.

The Commission is interested in stakeholder views on each of these pathways.

A summary of the key aspects of each of these pathways is provided below in Table 5.3 with further detail set out in the following sections.

Table 5.3: **Summary of the enduring PFR Pathways**

<table>
<tr><th>POLICY ELEMENT</th><th>PFR PATHWAY 1

MANDATORY PFR (NARROW RESPONSE BAND)</th><th>PFR PATHWAY 2

MANDATORY PFR (MODERATE OR WIDE RESPONSE BAND)</th><th>PATHWAY 3

NO MANDATORY REQUIREMENT</th></tr>
<tr><td>1. Role of Mandatory PFR</td><td>Existing mandatory requirement maintained.</td><td>Mandatory requirement maintained and revised. Frequency response band (PFCB) to widened to moderate or wide setting.</td><td>No mandatory PFR requirement.</td></tr>
<tr><td rowspan="2">2. Procurement arrangements for narrow band PFR</td><td>No change. Existing market ancillary service arrangements likely to be sufficient, subject to confirmation by AEMO.</td><td colspan="2">Option 1 – new market ancillary service(s)

New market ancillary service(s) would enable plant to provide automatic frequency regulation and respond to small frequency deviations. (Primary regulating services)</td></tr>
<tr><td colspan="3">Option 2 – incentive based voluntary provision

Voluntary provision of narrow band PFR in response to improved incentive arrangements</td></tr>
<tr><td>3. Pricing arrangements for PFR</td><td>N/A</td><td colspan="2">Option 1 – new market ancillary service(s)

Pricing arrangements are an integral part of the development of the new market ancillary service(s).

Default approach is market-based pricing similar to the arrangements used for the existing market ancillary services.</td></tr>
</table>

POLICY ELEMENT	PFR PATHWAY 1 MANDATORY PFR (NARROW RESPONSE BAND)	PFR PATHWAY 2 MANDATORY PFR (MODERATE OR WIDE RESPONSE BAND)	PATHWAY 3 NO MANDATORY REQUIREMENT
	Option 2 – incentive based voluntary provision New pricing arrangements to value and incentivise PFR provision outside of FCAS enablement. This could include valuation of positive contribution factors determined through the causer pays process (double-sided causer pays) or an alternative pricing arrangement, such as regulated pricing.		
4. Cost allocation approach	It is proposed that costs associated with double-sided causer pays or a regulated pricing would be incorporated into the existing causer pays process for allocation of regulation costs.		
5. Revised Frequency operating standard (FOS)	FOS to confirm the required frequency performance during normal operation and the PFCB, which forms part of the mandatory PFR arrangement.		FOS to confirm the required frequency performance during normal operation.

Source: AEMC
Note: Further detail on each of these pathways is provided below.

5.7.1 Pathway 1: Mandatory PFR (narrow response band)

Role of mandatory PFR

Under pathway 1, the framework established through the *Mandatory PFR rule* would be confirmed as part of the enduring PFR arrangements in the NEM. Under the existing Mandatory PFR arrangement all scheduled and semi-scheduled generation plant are required to respond to small frequency deviations in accordance with approved frequency response settings, regardless of whether or not each plant is enabled to provide frequency responsive reserves.

Effectively this approach allocates all capable scheduled and semi-scheduled generation with "regulation duty" for automatic PFR. This universal PFR works together with secondary regulation services to control frequency close to 50Hz during normal operation.

Procurement arrangements

Under pathway 1, the proposed method of procurement of reserves for narrow band PFR is through the existing market ancillary service arrangements. In effect, the procurement of contingency reserves would also provide reserves for PFR to help control system frequency during normal operation.

If AEMO confirms that the existing FCAS arrangements are sufficient for the procurement of frequency responsive reserves then new additional procurement mechanism are not likely to be required under a mandatory narrow PFR regime. As described above, AEMO will provide advice on this.

Pricing arrangements

This pathway is likely to lead to some under-pricing of PFR, particularly for PFR provided by market participants that are not enabled to provide FCAS through the market ancillary service arrangements. Therefore, under pathway 1 it would be envisaged that the implementation of stronger pricing arrangements for PFR would be provided outside of the existing FCAS markets.

The new pricing arrangements could include valuation of positive contribution factors determined through the causer pays process (double-sided causer pays) or an alternative arrangement, such as regulated pricing. Double sided causer pays, as a form of deviation pricing, would provide a flexible performance-based pricing arrangement for the valuation of PFR during normal operation.[180] Ideally, plant frequency performance would be measured with respect to system frequency rather than FI, such that the performance metric is easily available to market participants to guide operational decisions for their plant.[181]

While the full economic efficiency promised through a double-sided causer pays arrangement would not be realised when combined with the mandatory narrow PFR arrangement, the operational risks associated with double-sided causer pays would also be lessened when combined with the existing mandatory PFR arrangement.

In the event that further analysis and the advice from AEMO, identifies material concerns related to the implementation of a double-sided causer pays approach, a form of regulated pricing for PFR delivery outside of FCAS enablement could help correct for under-pricing of PFR.

5.7.2 Pathway 2: Mandatory PFR (moderate or wide response band)

Role of mandatory PFR

Under this approach the Mandatory PFR arrangement would be revised to widen the Primary frequency control band (PFCB), such that the mandatory PFR was focused on universal response to contingency events, and a new complementary arrangement would be introduced to value PFR provided in response to small frequency deviations during normal operation. The PFCB could either be specified at a moderate setting close to the NOFB, 49.85Hz - 50.15Hz, or a wider setting, subject to AEMO advice on the operational viability of this setting.[182]

180 Further detail on these pricing arrangements is included in section 5.6.2.

181 FI is a parameter used within AEMO's systems to indicate the amount of generation required to be added or removed to restore the frequency to 50 Hz.

182 The role of the PFCB in the governance arrangements for Mandatory PFR is described in section 5.1.3.

The AEC has expressed support for two variations of this pathway 2. The AEC supports the revision of the PFCB to provide mandatory wide-band response for non-credible contingencies where the system frequency exceeds the range 49.5Hz – 50.5Hz. To complement the wider mandatory PFR arrangement, the AEC proposes the implementation of either a double-sided causer pays regime or a new market ancillary service of narrow band PFR.[183] The AEC pathways are a sub-set of the pathways for enduring PFR described in this paper.

Procurement arrangements

Previous analysis and consultation supports the view that the existing FCAS market arrangement would not provide sufficient narrow band PFR on their own in the absence of a complementary arrangement to encourage or require the provision of PFR during normal operation. Therefore, under pathway 2, a new arrangement would be required to support the provision of PFR to respond automatically to small frequency deviations during normal operation and complement the secondary control provided through the existing regulation services.

New procurement arrangement could be either:

- procurement option 1 – a new market ancillary service(s) required to enable plant to provide automatic frequency regulation and respond to small frequency deviations. (Primary regulating services); or
- procurement option 2 – the voluntary provision of narrow band PFR in response to improved incentive arrangements.

The detail on each of these procurement options is described above in section 5.6.1.

Under the voluntary approach, the pricing arrangements provide the only incentive for provision of narrow band PFR, as there would be no mandatory requirement for response to small frequency deviations. It is likely that such a voluntary incentive based approach would require further investigation and potentially a trial period in order to validate its operational effectiveness. This validation process would be needed to provide confidence that the regime would deliver the required level of PFR and that it would not result in any unintended negative consequences that may jeopardise the power system or the efficient operation of the electricity market.

On the other hand, a market ancillary service approach for primary regulating services would provide AEMO with increased operational certainty over the performance and the quantity of PFR during normal operation. Under this approach, AEMO would be able to specify the performance requirements for the primary regulating service in the MASS and have control of the quantity of service enabled in the power system at all times.

Pricing arrangements

Under pathway 2, the pricing arrangement depend on the preferred procurement option for narrow band PFR.

183 AEC, Submission to the second consultation paper – *Primary frequency response incentive arrangements* - 2 July 2020, received 22 September 2020, p.26.

Option 1 – *New market ancillary service(s)*

In the case of procurement via new FCAS market arrangements, the pricing arrangements would likely be similar to the arrangements used for the existing market ancillary services. Market based pricing arrangements could operate independently of, or in combination with additional performance-based pricing regimes that may incentivise additional PFR provided by power system plant.

Option 2 – Voluntary incentive-based provision

In the case of voluntary PFR provision, the potential pricing arrangements would be similar to the pricing arrangements described in section 5.7.1, which could be either a double-sided causer pays approach or a regulated pricing approach.

The detail on each of these pricing options is described above in section 5.6.2.

The Commission is seeking stakeholder input and advice from AEMO on the operational viability and economic benefit of each of these procurement and pricing options under pathway 2.

5.7.3 Pathway 3: No mandatory PFR requirement

Role of mandatory PFR

Under this approach the Mandatory PFR arrangement would cease to apply.

In the absence of the AEMC making a new rule, the Mandatory PFR requirement will sunset on 4 June 2023.

That said, the Commission is committed to the development of enduring PFR arrangements through the *PFR incentives* rule change. This is likely to include an enduring role for a mandatory PFR arrangement as described in section 5.1.3.

A mandatory PFR arrangement can provide a valuable safety net to increase the resilience of the power system to large non-credible contingency events. The absence of a mandatory PFR arrangement would increase the reliance on Emergency frequency control schemes, such as under-frequency load shedding and over-frequency generation shedding to re-stabilise the power system frequency following large frequency disturbances. AEMO has previously advised that these schemes are intended for intermittent emergency use only and that it is not appropriate to rely on these schemes on a regular basis to manage contingency events that exceed the capacity of the FCAS market design.[184]

Procurement and pricing arrangements

The procurement and pricing arrangements for narrow band PFR under pathway 3 are similar to those described under pathway 2 as described in section 5.7.2.

184 AEMO, Mandatory primary frequency response -Electricity rule change proposal, 16 August 2019, p.25.

QUESTION 17: PATHWAYS FOR ENDURING PFR ARRANGEMENTS

In relation to the pathways for enduring PFR arrangements set out in section 5.7:

- What are stakeholders' views on the enduring PFR pathways?
- Do stakeholders agree with the Commission's preliminary preference for pathway two? (the widening of the PFCB and the introduction of market arrangements for narrow band PFR)

5.8 Future review of the frequency operating standard

The development of new arrangements for the provision of PFR during normal operation is interdependent with the determination of the standard for system frequency performance during normal operation. The development of enduring PFR arrangements is likely to necessitate a future review of the Frequency operating standard for normal operation.

Under the NER, the required system frequency performance is specified in the Frequency Operating Standard (FOS). AEMO is responsible for operating the power system in accordance with the FOS. The FOS specifies, with the appropriate detail, the expected frequency performance of the power system during normal operation and following contingency events. As the frequency control arrangements are revised to reflect the changing needs of the power system, the frequency operating standard may require updating to reflect the expectations for future power system frequency control.

AEMO published a frequency control work plan in September 2020 as part of its follow up work to the *Renewable Integration Study – stage 1 report*. The frequency control work plan provides further details on AEMO's activities related to the ongoing reform of the frequency control frameworks for the NEM. One of the actions in the work plan is an investigation by AEMO of how the FOS specifies the operational objectives for frequency management in the power system including the target frequency performance during normal operation.[185]

This investigation, "FOS Criteria Options Analysis", will be informed by AEMO's monitoring of system performance as it coordinates changes to plant settings through the implementation of the Mandatory PFR arrangements. The investigation will inform the design of the enduring arrangements for PFR, that the AEMC will develop through the assessment of the *PFR incentives* rule change request. It will also inform the scope and objectives for a future review of the FOS by the Reliability Panel.

The Commission envisages that a review of the FOS by the Panel will potentially commence in Q3 2021, following receipt of AEMO's advice on the FOS for normal operation, and further progress by the Commission on the form of the enduring PFR arrangements in the NER.

The Commission welcomes stakeholder views on this timing.

185 AEMO, Frequency Control Work Plan, 25 September 2020, p.10.

QUESTION 18: FUTURE REVIEW OF THE FOS

What are stakeholders' views of the Commission's proposed approach towards a future review of the FOS as part of the development of enduring PFR arrangements?

5.9 Reforms to the NER relating to cost allocation for regulation services – causer pays

In addition to the potential for pricing PFR through the valuation of positive contribution factors, further changes to the causer pays framework have been identified by the AEMC and AEMO previously, including:

- Improving transparency and reducing the complexity of the causer pays process
- Aligning participants' impacts on system frequency with the costs they incur
- Removal or shortening of the ten-day notice period for contribution factors
- Calculation of local contribution factors for local FCAS requirements
- Inclusion of non-metered generation within the residual component for cost allocation

The Commission is interested in stakeholder views on the proposed reforms to NER in relation to the Causer pays process as described below.

5.9.1 Transparency and complexity of the causer pays process

When the cost allocation arrangements are not transparent, or unnecessarily complicated, participants may misinterpret the likely costs associated with their actions, giving rise to potentially unintended consequences.

The current causer pays arrangements for the recovery of the costs of regulating FCAS are an example of a complex and opaque incentive framework. The current arrangements could be improved and simplified to provide greater clarity on how market participant behaviour relates to allocation of regulation costs.

One potential simplification is the measurement of plant performance for the determination of contribution factors against system frequency rather than FI. The Commission's views on this proposal are discussed above under section 5.6.2 in relation to frequency response deviation pricing.

Alternatively, the FI variable could be made available to market participants in real time such that market participants could have access to the variable against which their plant performance is measured.

5.9.2 Alignment and shortening of the sample and application periods

AEMO is required to publish contribution factors with a notice period of at least ten business days prior to the application of those factors. Currently, AEMO has chosen to adopt a 28-day averaging period for the calculation of the contribution factors as outlined in AEMO's causer pays procedure. Taken together with the notice period, this means that the allocation of regulation FCAS costs for a particular 28-day period is based on performance contribution factors determined over a four-week period commencing around six weeks earlier.

The misalignment of the application of costs with the causers of the costs has the potential to give rise to unintended incentives. Market participants may gain financial benefit from acting in a way that is contrary to the intention of the incentive framework.

There would likely be benefits in aligning the average period used for calculation of contribution factors with the period over which the costs are incurred over a reasonable time interval. As described in section 5.3.3, the AEC have proposed that the appropriate time interval for causer pays transactions be based on the 4-second measurement of a participant's plant performance with respect to its dispatch target and the system frequency at that time. Another alternative could involve the calculation of contribution factors be based on the five-minute dispatch interval to achieve consistency with the energy market.

5.9.3 Removal or shortening of the ten-day notice period

AEMO is required to publish contribution factors with a notice period of at least ten business days prior to the application of those factors.[186]

In the *Frequency control frameworks review*, the Commission identified that there may be benefits associated with the removal or reduction of this ten-day notice period based on the view that the causer pays incentive is likely to be more effective if the performance measurement is closely aligned to the application of associated costs, preferably in real time.

Any benefits from reducing or removing the ten-day notice period are only likely to be realised if the change is undertaken in combination with an alignment of the sample and application periods.

Through AEMO’s recent review of the causer pays process, it acknowledged that the notice period could be reviewed as part of a future rule change proposal.[187]

5.9.4 Calculation of local contribution factors for local FCAS requirements

Through its 2018 consultation on the causer pays procedure, AEMO identified that the approach to allocation of regulation costs associated with local requirements could be improved to more accurately reflect a participants’ share of regional FCAS costs.[188]

Local regulation FCAS requirements are requirements for a regulation services to be provided from within a specific NEM region, as opposed to global requirements that can be sourced from any NEM region.[189] When there is a local requirement for regulation services, AEMO recovers costs from all participants with a market generating unit or customer load in the region, using the NEM-wide (portfolio) contribution factor for each of those participants.[190]

186 Clause 3.15.6A(na) of the NER.

187 AEMO, *Regulation FCAS Contribution Factor Procedure: Final Report and Determination*, 9 November 2018, p.14.

188 Ibid., p.12.

189 Local FCAS requirements help AEMO to manage regional power system risks, such as the risk of islanding or operation of a power system island. These requirements are implemented through constraints in NEMDE.

190 AEMO, *Regulation FCAS Contribution Factor Procedure: Draft Report and Determination, 6 April 2018, pp.10-11.*

While this approach ensures that local costs are only recovered from local participants, it also allows the performance of all of a market participant's appropriately metered facilities to affect the contribution factor for local requirements, including those that are outside the region of the local requirement.[191]

AEMO concluded that local contribution factors should be adopted by a process of pre-calculating seven sets of factors to be calculated in advance for each market participant, including

- A Global factor for the NEM wide requirements
- A Mainland NEM factor (aggregate of mainland regions)
- A Local factor for each separate region (SA, QLD, NSW, VIC, TAS)

AEMO considered that a change to the NER and subsequent Procedure and system changes would be required to implement this approach.[192]

The Commission understands that the drafting of NER clauses 3.15.6A (i-k) could be revised to support AEMO's preferred approach and confirm that separate contribution factors may be determined for each NEM region. The Commission recognises that AEMO's proposed approach is an extension of the principles that underpin the causer pays process for the allocation of regulation costs. It is not appropriate for a market participant's plant in one NEM region to be allocated costs for a local requirement for regulation services in another region. Therefore, it is likely to be appropriate that the NER be revised to support AEMO's proposed change.

5.9.5 Inclusion of non-metered generation in the residual component

Through its 2018 consultation on the causer pays procedure, AEMO identified a potential improvement to the Causer pays process that would address what AEMO perceived to be an inconsistency in the cost allocation process. The change relates to the inclusion of non-metered generation within the allocation of costs through the residual component of the causer pays process. The proposed change was explained by AEMO in its issues paper for the 2018 *Causer pays procedure consultation*:[193]

> In addition to generator performance, the causer pays methodology also considers the impacts of demand volatility, and demand forecasting error at 4-second resolution. These demand components inherently include deviations due to non-metered generation.
>
> The causer pays factors resulting from demand contributions (including non-metered generation) are combined and allocated to a quantity known as the 'residual'. However, NER clause 3.15.6A(i)(2) requires that this residual component be recovered only from Market Customers. This means that non-metered generation may not be allocated costs under the current methodology."

191 Ibid.

192 Ibid.

193 AEMO, *Causer pays procedure consultation – Issues paper*, pp.14-15. December 2016.

Through consultation with stakeholders AEMO concluded that:[194]

> the NER be changed to allow the residual factor of regulated FCAS cost recovery to be apportioned to both market customers and non-metered market generation

The initial position is that the residual costs determined through the causer pays procedure should be allocated proportionally to each market participant that does not have metering to support the determination of an individual contribution factor, including non-metered generation and non-metered load from market customers.[195] It is not appropriate for non-metered generation to be excluded from the allocation of the residual share of regulation FCAS costs, effectively excluding this class of participant from any regulation cost liability. The inclusion of this class of market participant within the residual will spread the residual costs of regulation services more broadly and correct an oversight in the original causer pays framework.

QUESTION 19: REFORMS TO THE NER RELATING TO COST ALLOCATION FOR REGULATION SERVICES – CAUSER PAYS

In relation to the proposed reforms to the NER relating to the allocation of regulation costs, set out in section 5.9:

- What are stakeholders' views on the proposal to allocate regulation costs on the basis of performance against system frequency as opposed to Frequency indicator(FI)?
- What are stakeholders' views on the proposal to align the sample and application periods for determination of causer pays factors and shorten the application period to 5 minutes, in line with the NEM dispatch interval?
- What are stakeholders' views on the removal or shortening of the ten-day notice period for causer pays contribution factors?
- What are stakeholders' views on AEMO's proposal to pre-calculate seven sets of contribution factors including local contribution factors?
- What are stakeholders' views of AEMO proposal to include non-metered generation in the residual component for allocation of regulation costs?

194 AEMO, *Regulation FCAS Contribution Factor Procedure: Final Report and Determination*, 9 November 2018, p.14.

195 In this context the term "non-metered" refers to a plant that does not support 4-second SCADA metering. SCADA or Supervisory Control and Data Acquisition, is a control system architecture that includes measurement, computing, communications and control functionality. Market participants who establish a SCADA link with AEMO receive information including dispatch information and send plant operating information, including generation output or energy consumption. AEMO uses the 4-second SCADA data to calculate participant contribution factors under the causer pays procedure, thus any generation or load without a SCADA connection to AEMO is referred to here as "non-metered".

ABBREVIATIONS

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic generation control system
Commission	See AEMC
DER	Distribution energy resources
DSCP	Double-sided causer-pays
ESB	Energy Security Board
ESS	Essential system services
FFR	Fast frequency response
FI	Frequency indicator
FOS	Frequency operating standard
IBFFR	Inverter based fast frequency response
ISP	Integrated System Plan
MASS	Market ancillary service specification
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market dispatch engine
NEO	National electricity objective
NOFB	Normal operating frequency band
PFCB	Primary frequency control band
PFR	Primary frequency response
PFRR	Primary frequency response requirements
QNI	Queensland - New South Wales Interconnector
SOLI	secure operating level of inertia
Rocof	rate of change of frequency
TNSP	Transmission network service provider
VPP	virtual power plant
VRE	variable renewable energy (generation)
WEM	Wholesale electricity market (Western Australia)

A ECONOMIC ANALYSIS — FFR

This appendix provides further detail on the analysis and findings described in section 4.5.2.

The Commission has undertaken analysis to describe the potential increase in requirement for fast raise services in the NEM under a future where the level of inertia in the power system is decreasing but where there are no new arrangements for provision of FFR. The analytical method is based on the relationships developed by AEMO through its Renewable Integration Study between the dynamic requirement for R6 and inertia as shown in Figure 4.4 to the projected inertia levels from the ISP central and step change scenarios shown in Figure 4.2.

The following assumptions underpin this analysis:

- Projected system inertia is for the mainland NEM, excluding Tasmania
- Largest credible risk is static at 750MW
- System load is static at 18 680MW – RIS low load scenario
- System load relief is static at 0.5%

The analysis is not expected to be an accurate forecast of the future state of the power system, but instead it provides an indication of the general trends with respect to system inertia and the requirement for fast responding contingency reserves. This is informative in considering the materiality of the issues raised by Infigen in its rule change request.

The projected decrease in mainland NEM inertia levels is likely to be limited by AEMO's proposal to consider the implementation of an inertia safety net for system intact operation in the order of 55,000MWs to 65,000MWs. In making this proposal, AEMO noted that historical levels of inertia in the mainland NEM have not been below 68,000MWs. AEMO considers that the transition to lower levels of system inertia requires a staged approach, through which an inertia safety net would be progressively revised as operational experience is built and additional measures are put in place to ensure system security.[196] The process for the implementation of the proposed inertia safety net is to be progressed through item 10 of AEMO's *Frequency control work plan*, which is scheduled to commence in March 2021.[197] Further commentary is expected on this through AEMO's advice, *FFR Implementation options report,* described in section 4.6.

Figure A.1 shows the projected increase in dynamic R6 requirements relative to the static requirement of 655.7MW for the assumed system conditions listed above. The static requirement is based on the value set out in AEMO's *Renewable Integration Study – stage 1 report* for the calculation assumptions listed above.[198] The static requirement represents the minimum required replacement energy to stabilise system frequency based on the assumed system conditions.[199] The dynamic requirement recognises the dynamic nature of frequency

196 AEMO, *Renewable Integration Study – Stage 1 report*, March 2020, p.10, 47-48.

197 AEMO, Frequency control work plan, 25 September 2020, p.11.

198 AEMO, *Renewable Integration Study – Stage 1 report - Appendix B*: Frequency control, March 2020, p.21-22.

199 Ibid. p.21.

response, including the impact of system inertia and delays in delivery of replacement energy. Faster responding active power response acts to reduce the gap between the dynamic and the static requirement. The shaded cells in Figure A.1 show projected future states that result from system inertia levels below AEMO's proposed initial inertia safety net of 65,000MWs.

However, it is unlikely that these future states will come to pass without some form of remedial action through either the proposed inertia safety net and/or new market arrangements for FFR and inertia. They are included to provide a broader context of the relationship between inertia and fast responsive reserves.

Figure A.1: Projected increase in R6 requirements - ISP central and step change scenarios

	2020-21	2024-25	2029-30	2034-35	2039-40
Percentage change - R6 requirement – ISP central scenario	168%	174%	184%	194%	241%
Percentage change - R6 requirement - ISP step change scenario	167%	181%	210%	241%	254%

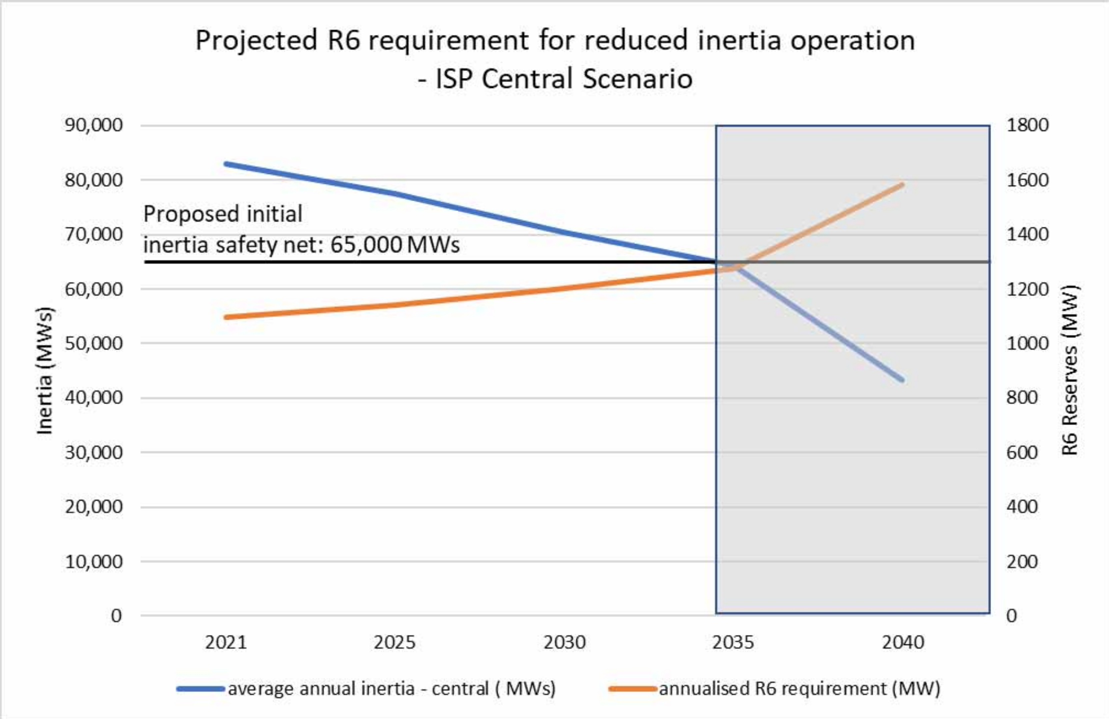
Source: AEMC analysis

Note: Based on the projected inertia levels under the 2020 ISP central and step change scenarios combined with the relationship between inertia and the dynamic R6 requirement from AEMO's — *Renewable Integration Study — stage 1*.

The results of this analysis for the mainland NEM are shown in Figure A.2 and Figure A.3 below. In each case a black line is included in the chart showing the proposed initial value of 65,000MWs for an inertia safety net. As above, the projections that show mainland average inertia levels below 65,000MWs are shaded grey, indicating that the confidence over these projections is low.

Figure A.2 shows the projected average annual inertia and corresponding R6 values based on the ISP central scenario. Under this scenario the average annual inertia level reduces steadily from the current level of 83,000MWs in 2020-21 to around 70,000MWs in 2029-30. In the absence of arrangements to provide for additional FFR or inertia, the R6 requirement would be expected to rise from the current static level of 655.7MW for a 750MW contingency under low load conditions to around 1200MW in 2029-30. Based on the 5-year average historical annual revenues for R6 services this could translate into increased costs for R6 services in the order of $60 Million per annum by 2030. The historic average requirements for R6 and annual revenues are included for reference in Figure A.4.

Figure A.2: Projected R6 requirement — ISP central scenario



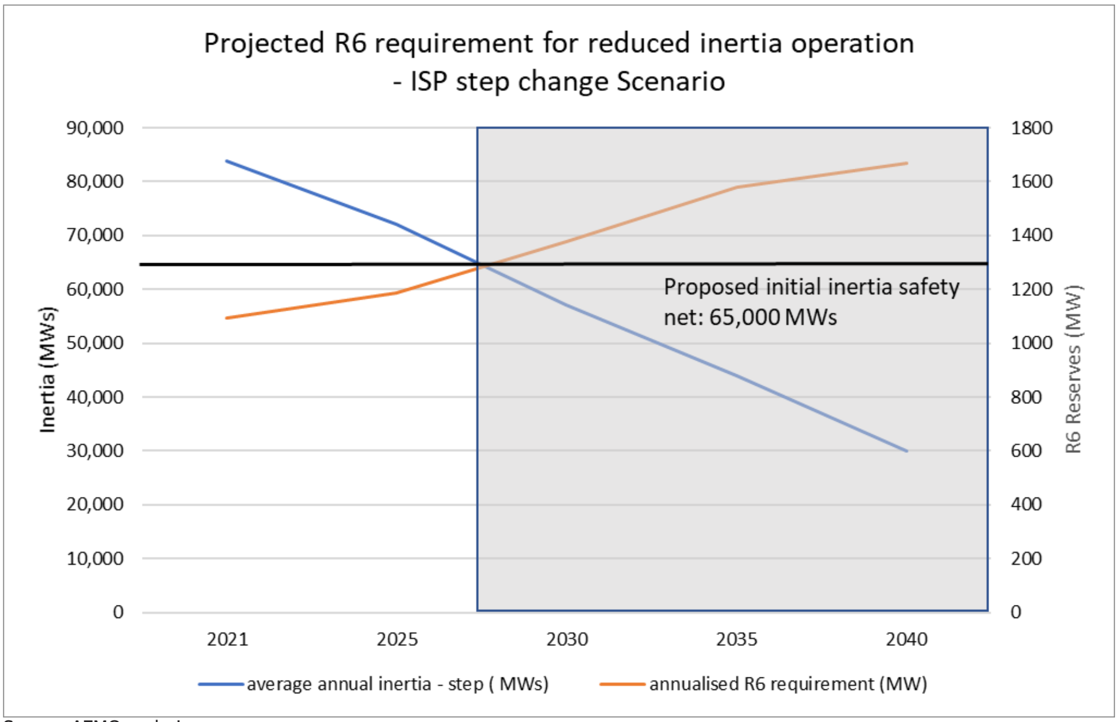
Source: AEMC analysis

Note: Based on the projected inertia levels under the 2020 ISP central scenario combined with the relationship between inertia and the dynamic R6 requirement from AEMO's — *Renewable Integration Study — stage 1*.

The static level represents the minimum R6 requirement for the given system conditions, that is it is based on the contingency size and the impact of load relief. In theory FFR could help reduce the R6 requirement toward the static level. In theory, the dispatch of R6, FFR and inertia could be co-optimised to deliver efficient outcomes based on the relative price of each service and an improved understanding of system operation supported by dynamic contingency analysis.

Figure A.3 shows the projected average annual inertia and corresponding R6 values based on the ISP step change scenario. Under this scenario the average annual inertia level decreases more quickly from the current level of 83,000MWs in 2020-21 to around 57,000MWs in 2029-30. In the absence of arrangements to provide for additional FFR or inertia, the R6 requirement would be expected to rise from the current static level of 655.7MW for a 750MW contingency under low load conditions to around 1200MW five years earlier in 2024-25.

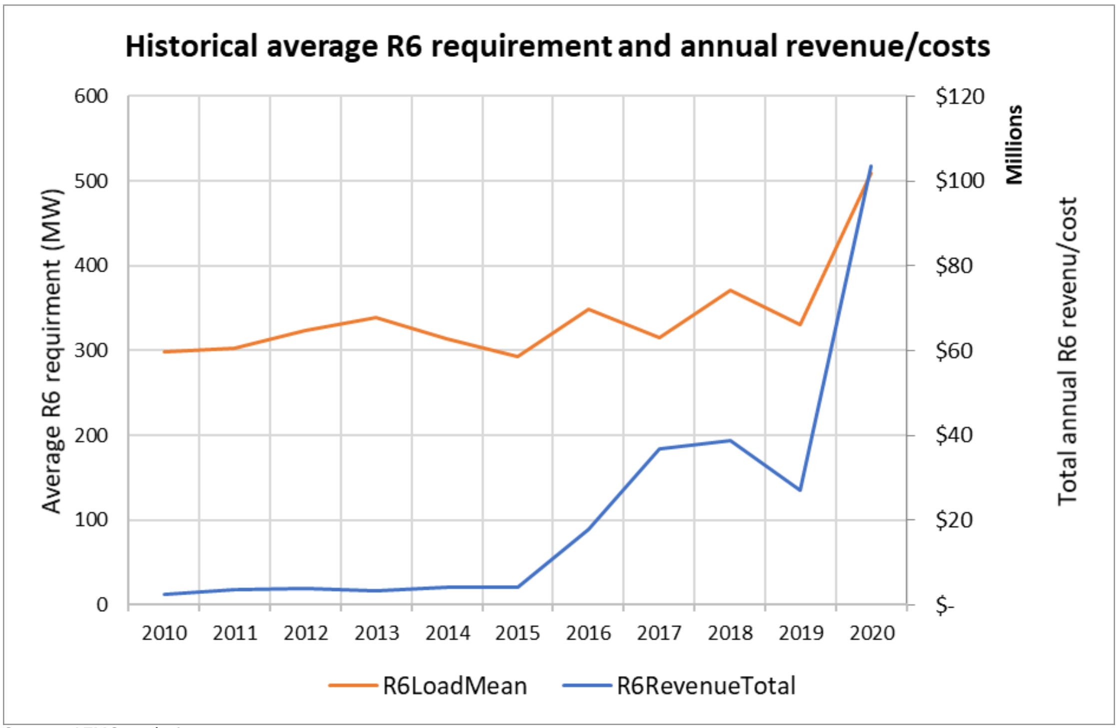
Figure A.3: Projected R6 requirement — ISP step change scenario



Source: AEMC analysis

Note: Based on the projected inertia levels under the 2020 ISP step change scenario combined with the relationship between inertia and the dynamic R6 requirement from AEMO's — *Renewable Integration Study — stage 1*.

Figure A.4: Average R6 requirement and annual revenue 2010 - 2020



Source: AEMC analysis
Note: Based on data from AEMO's Market management system(MMS) database.

B EXISTING FREQUENCY ARRANGEMENTS

This appendix describes the following elements of the existing frequency control frameworks for the NEM:

- Appendix B.1 describes the generator technical performance standards (GTPS).
- Appendix B.2 describes the existing inertia framework.
- Appendix B.3 describes the arrangements for FCAS.
- Appendix B.4 describes the role of Emergency frequency control schemes (EFCS).

B.1 Generator technical performance standards

Equipment that makes up and connects to the power system must perform to certain levels of technical capability. This helps AEMO maintain the power system in a secure and safe operating state and manage the risk of major supply disruptions. The levels of performance for equipment connecting to the power system are set out in performance standards for each connection. These performance standards are reached through a negotiating framework that is set out in the NER.

'Access standards' in the NER define the range of the technical requirements for the operation of equipment when negotiating a connection. These access standards include a range from the minimum to the automatic access standard. For each technical requirement defined by the access standards, a connection applicant must either:

- meet the automatic access standard, in which case the equipment will not be denied access because of that technical requirement; or
- negotiate a standard of performance with the local network service provider that is at or above the minimum access standard and below the automatic access standard.[200]

The generator access standards in the NER cover a range of technical capabilities for connecting generators, including, among other things, frequency control and response to frequency disturbances during and following contingency events.[201] Clause 4.4.2(b) of the Rules sets out the obligations on Generators in relation to compliance with the technical requirements in clause S5.2.5.11, including being capable of operating in frequency response mode. Clause 4.4.2(c1) of the Rules sets out the obligations on Scheduled and Semi-Scheduled Generators in relation to the operation of their generating systems in accordance with the Primary Frequency Response Requirements.

Broadly, the automatic access standard that applies to generator frequency control is that:

- the generating system's output should not worsen any frequency deviation

200 The connection applicant may also need to negotiate with AEMO on access standards that are AEMO advisory matters

201 This section summarises the requirements in the NER that apply to generators connected after the 8 March 2007, when the National Electricity Amendment (Technical Standards for Wind Generation and other Generator Connections) Rule was made. Chapter 11 of the NER contains a transitional rule, clause 11.10.3, that allows for preexisting access standards to continue to apply.

- the generating system must be capable of automatically increasing or decreasing its output to help restore the system frequency to within the normal operating frequency band.[202]

The minimum access standard for generator frequency control does not directly refer to the frequency operating standard. It requires that a generator's output must not:

- increase in response to a rise in system frequency
- decrease more than 2 per cent per Hz in response to fall in system frequency.[203]

B.2 Inertia framework

The NER require AEMO to determine the inertia requirements for inertia sub-networks (typically NEM regions) through the application of the inertia requirements methodology that is developed by AEMO.[204]

For each inertia sub-network, the inertia requirements are:[205]

1. the **minimum threshold level of inertia**, required to operate the inertia sub-network in a satisfactory operating state when it is islanded
2. the **secure operating level of inertia** (SOLI), required to operate the inertia sub-network in a secure operating state when it is islanded

For each inertia sub-network, AEMO is required to assess whether there is likely to be an inertia shortfall between the inertia typically provided and the required level of inertia (minimum threshold and SOLI).[206]

Once an inertia shortfall has been declared by AEMO in an inertia sub-network, the TNSP who is the Inertia Service Provider for that sub-network is obliged to make inertia network services available that when enabled will provide inertia to the required level. Inertia network services could include contracting with synchronous generators or providing a network solution such as the operation of synchronous condensers).[207] The TNSP may also ask AEMO to approve inertia support activities (which are not inertia network services and which act to adjust the relevant minimum level of inertia) as an alternative solution, and AEMO can approve those activities if it is satisfied that the activities will contribute to the operation of the inertia sub-network in a satisfactory or secure operating state.[208] Inertia support activities may include installing or contracting for the provision of frequency control services, (such as FFR) installing emergency protection schemes or contracting with Generators in relation to the operation of their generating units in specified conditions.

202 See S5.2.5.11(b) of the NER
203 See S5.2.5.11(c) of the NER.
204 NER Clause 5.20B.2(a)
205 NER Clause 5.20B.2(b)
206 NER Clause 5.20B.3(a)
207 NER Clause 5.20.B.4
208 NER Clause 5.20B.5

B.3 Frequency control ancillary services

The NER includes a framework for the provision of eight market ancillary services for active power reserves and control of power system frequency.[209] These services, known collectively as frequency control ancillary services (FCAS), include the raise and lower regulation services, for the centrally controlled regulation of frequency under normal operating conditions, and the six raise and lower contingency services, for the provision of active power response following contingency events that result in a shortage or excess of generation.

Participants must register with AEMO to participate in each of the FCAS markets. Once registered, a service provider can participate in an FCAS market by submitting an appropriate FCAS offer or bid for that service. AEMO determines the amount of FCAS that is required to manage the power system frequency in accordance with the frequency operating standard. For each five-minute dispatch interval, the National Electricity Market dispatch engine enables sufficient FCAS in each market, and the price for each service is set by the highest enabled bid in each case. Providers of FCAS are paid for the amount of FCAS in terms of dollars per megawatt enabled per hour. That is, generators receive a payment irrespective of whether the service is required to be delivered. Where the service is required to be delivered, the generator also receives payment for any energy associated with the provision of the service.

Frequency control services in the NEM are referred to as either raise or lower services.

- A **raise service** is a service that acts to raise system frequency through the provision of additional active power delivery or the reduction in consumer demand.
- A **lower service** is a service that acts to lower system frequency through the reduction in active power delivery or the increase in consumer demand.

There are two types of **regulating FCAS**:[210]

1. Regulating raise service. Used to correct a minor drop in frequency.
2. Regulating lower service. Used to correct a minor rise in frequency.

These regulation services provide secondary frequency control that is centrally coordinated by AEMO's automatic generator control (AGC) system. The AGC monitors minor changes in the power system frequency and adjusts the output of units enabled to provide regulating FCAS to correct small frequency deviations, and to correct the accumulated frequency error over time.[211]

There are six types of **Contingency FCAS** divided into raise and lower services at three different speeds of response and sustain time: fast slow and delayed. As such, there are six distinct contingency FCAS services:[212]

- Fast raise and lower services
- Slow raise and lower services

209 NER Clause 3.11.2(a).

210 NER Clause 3.11.2(a)

211 This accumulated frequency error over time is known as accumulated time error, which is a measure of the cumulative sum of the difference between the actual power system frequency over time and the nominal system frequency of 50Hz.

212 NER Clause 3.11.2(a)

- Delayed raise and lower services

In accordance with the NER, AEMO specifies the requirements for each of the market ancillary services in its Market ancillary service specification (MASS).[213] The MASS sets out how the market arrangements for FCAS work, including the description and specification for each of the various products. The MASS includes a detailed description of each of the FCAS products along with the performance parameters and requirements which must be satisfied to register as a provider and participate in the market arrangements for the dispatch of these services. Under the MASS, potential market ancillary service providers are allocated a maximum quantity for each service they wish to provide as part of the registration process. The registered quantity is based on the unit's response to a standard frequency ramp for each of the contingency products. Valuation for each of the contingency services is based on the ability to respond over a set time frame as follows.

- Fast services (six-second raise and lower or R6/L6) — the ability to respond to a rapid change in system frequency within the first six seconds of a frequency disturbance. The standard response for an R6/L6 product reaches maximum delivery after six seconds before tapering off to zero after 60 seconds.[214]
- Slow services (sixty-second raise and lower or R60/L60) — the ability of the unit to respond to a rapid change in system frequency in the period between six and sixty seconds following a frequency disturbance. The standard response for an R60/L60 product reaches maximum delivery after sixty seconds before tapering off to zero after five minutes.[215]
- Delayed services (five-minute raise and lower or R5/L5) — the ability of the unit to respond to a rapid change in system frequency in the period between six seconds and five minutes following a frequency disturbance. The standard response for an R5/L5 product reaches maximum delivery after five minutes before tapering off to zero after ten minutes.[216]

The current service specifications for the contingency services are illustrated below in figure C.1.

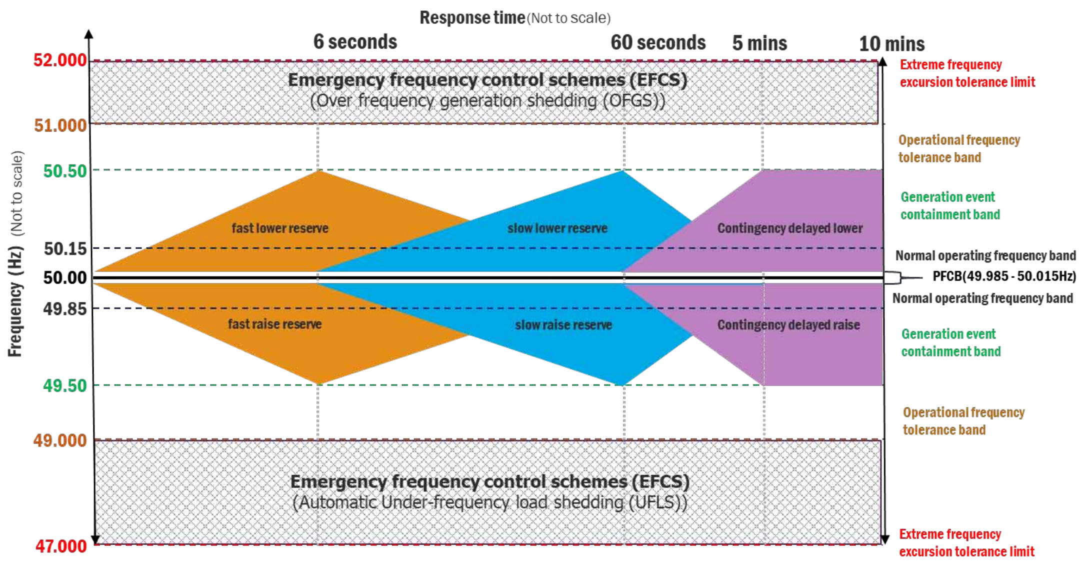
213 NER Clause 3.11.2(b)

214 AEMO, *Market ancillary service specification — V6.0*, 1 July 2020, pp.13-14.

215 Ibid. pp.17-18.

216 Ibid. pp.21-22.

Figure B.1: Contingency frequency response arrangements



Source: AEMC
Note: Based on the service specifications under AEMO's *Market ancillary service specification — V6.0*, published 1 July 2020.
Note: Shaded area denotes the indicative region of operation for Emergency frequency control schemes in the mainland NEM — further detail can be found in AEMO's 2020 *Power System Frequency Risk Review.*

B.3.1 FCAS market operation

In the NEM, FCAS is sourced from markets that operate in parallel to the wholesale energy market, with the dispatch outcomes in the energy and FCAS markets being optimised simultaneously so that total costs are minimised.

Participants must register with AEMO to participate in each distinct FCAS market. Once registered, a service provider can participate in an FCAS market by submitting an appropriate FCAS offer or bid for that service.

AEMO determines the amount of FCAS that is required to manage the power system frequency in accordance with the frequency operating standard. For each five minute dispatch interval, the National Electricity Market dispatch engine enables sufficient FCAS in each market, and the price for each service is set by the highest enabled bid in each case.

Providers of FCAS are paid for the amount of FCAS in terms of dollars per megawatt enabled per hour. That is, generators receive a payment irrespective of whether the service is required to be delivered. Where the service is required to be delivered, the generator also receives payment for any energy associated with the provision of the service.

Allocation of regulation service costs - Causer pays

The recovery of AEMO's payments to providers for regulating FCAS is based upon the "causer pays" methodology. This approach allocates regulation service costs to Market Generators

Market Small Generation Aggregators and Market Customers based on the degree to which they contribute to the need for regulation services.

AEMO is responsible for preparing a procedure which sets out the process for the determination of contribution factors for each market participant for the allocation of regulation service costs. This procedure is known as the causer pays procedure.

Allocation of contingency service costs

The costs of contingency raise services are recovered from Market Generators, as these services are required to manage the loss of the largest generator on the system. The costs of contingency lower services are recovered from Market Customers, as these services are required to manage the loss of the largest load or transmission element on the system.

B.4 Emergency frequency control schemes

Emergency frequency control schemes are schemes that help restore power system frequency in the event of extreme power system events, such as the simultaneous failure of multiple generators and/or transmission elements. The operational goal of emergency frequency control schemes is to act automatically to arrest any severe frequency deviation prior to breaching the extreme frequency excursion tolerance limit, and hence avoid a cascading failure and widespread blackout.

Traditional emergency frequency control schemes operate via frequency sensing relays that detect a frequency deviation beyond a predefined set point and act to disconnect any connected generation or load behind the relay. However, schemes can be set up to operate based on the occurrence of a particular contingency event, such as the failure of an inter connector. The installation and operation of emergency frequency control schemes is the responsibility of the relevant transmission network service provider (TNSP), while AEMO coordinates the overall performance of the schemes as part of its system security responsibility.[217]

AEMO is required to undertake a *Power system frequency risk review* at least every two years.[218] Through the *Power system frequency risk review* AEMO must assess the risks posed to the power system by non-credible contingency events and review the appropriateness of the mitigation measures in place, including the need for the declaration of protected events or changes to Emergency frequency control schemes.

217 NER cl 4.2.6(c)

218 NER cl 5.20A.1