RULE

Australian Energy Market Commission

DIRECTIONS PAPER

PRIMARY FREQUENCY RESPONSE INCENTIVE ARRANGEMENTS

PROPONENT

AEMO

19 MAY 2022

INQUIRIES

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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 As we move towards a lower emissions energy future, the provision of essential system services is one of the key priority areas of policy reform in the National Electricity Market (NEM). Lower cost, variable, inverter connected generation such as batteries, wind and solar are displacing synchronous and dispatchable thermal generation and this is creating challenges for how the security of the power system is managed.

2 The AEMC is committed to working with the other market bodies and stakeholders to deliver regulatory reforms that support the development of new and evolved ways to deliver essential system services which have traditionally been provided by synchronous thermal generators. In order to prepare for the future operating conditions, it will become increasingly important that the market and regulatory arrangements for the NEM align the economic incentives for market participants with the objectives for the operation of the power system. This will help AEMO to operate the system securely and deliver lowest cost outcomes for consumers over the long term.

3 As the market and system operator, AEMO is responsible for maintaining the power system in a secure operating state, such that it is resilient to disturbances caused by the unexpected failure of generation or transmission assets. One aspect of system security is the control of power system frequency within a narrow range around 50Hz. This is achieved by dynamically balancing electricity generation and consumption under both normal system conditions, when frequency varies within a narrow range of 0.15Hz either side of 50Hz, and in response to contingency events which can cause larger deviations in frequency of up to 1Hz.

4 This paper responds to stakeholder feedback on the draft determination published in September 2021

5 On 16 September 2021, the Commission published a draft rule determination and made a draft rule with respect to AEMO's rule change request, *Primary frequency response incentive arrangements.* The draft rule included the following key elements:

- Confirmation that the arrangements requiring scheduled and semi-scheduled generators to provide continuous narrow band control of system frequency — Mandatory Primary Frequency Response(PFR) — will endure beyond 4 June 2023. This element of the draft rule was supported by expert advice from AEMO and independent advice for GHD.
- Reforms to the 'causer pays' process for the allocation of regulation FCAS costs to deliver improved valuation and pricing of plant behaviour that impacts on power system frequency. These changes include the introduction of frequency performance payments to value positive contributions as measured during a trading interval and the allocation of associated costs to those who contribute to causing the deviation of system frequency.
- New reporting obligations for AEMO and the AER in relation to the levels of aggregate frequency responsiveness in the power system and the costs of frequency performance payments.

6 In response to the draft determination, most stakeholders expressed support for the development and implementation of performance-based incentive arrangements to recognise

the value provided by frequency responsive plant. However, many stakeholders were concerned by what they considered to be a lack of detail of the proposal for frequency performance payments set out in the draft rule and described in the draft determination. Stakeholders requested that the Commission undertake further analysis and consultation to clarify the design of the frequency performance payments arrangements and demonstrate how these arrangements would be sufficient to reward and encourage provision of PFR over the long term.

7 The Commission also acknowledges stakeholder feedback to the draft determination expressing concern for the proposed confirmation of Mandatory PFR as part of the enduring PFR arrangements in the NEM. The Commission will further consider and respond to stakeholder feedback on this element of the draft rule in the upcoming final determination and notes that this element of the draft rule is not the focus of this directions paper.

8 A revised frequency performance payments process

9 This directions paper sets out a revised process for frequency performance payments arrangements that responds to stakeholder feedback on the draft determination. As for the draft rule, the process is based on the measurement of active power deviations for power system plant, relative to their expected active power behaviour over each trading interval. The deviations are compared against the real time requirement to raise or lower the frequency in the power system to produce contribution factors for eligible generation and load.

10 The revised process is defined by a simplified frequency performance payment transaction that would apply separately for plant behaviour that contributes to the need to raise or lower the frequency of the power system. It is based on the product of three key elements for each trading interval:

- the valuation of active power deviations based on the price for the regulation raise or regulation lower service.
- the scaling of payments by the aggregate system requirement for corrective response — this is equivalent to the enablement volume for a market ancillary service.
- a contribution factor determined for each eligible unit of generation and load — this allocates payments and costs based on the proportional contribution of each plant to the need to raise or lower the frequency of the power system.

11 The revised process has been developed in collaboration with AEMO and IES Consulting and through consultation with the AEMC's frequency control stakeholder technical working group. IES prepared a companion report, *Frequency performance payments analysis*, which is published alongside this Directions paper on the AEMC project web page.

12 The IES report outlines investigations and modelling undertaken by IES to support and inform the revised frequency performance payments process. Based on historical data from 2021, the IES analysis estimates the scale of gross cash flows for frequency performance payments would be similar in size to the total costs for regulation services. The scale of net cash flows is estimated to be in the order of one third of the costs of regulation services, after netting of payments and cost allocation on a unit basis over time.

13 **This paper includes revised rule drafting**

14 Revised rule drafting is included in appendix D. The revised rule drafting:

- reflects the revised arrangements for frequency performance payments and cost recovery for regulation services as detailed above.
- incorporates changes to be made to the relevant provisions of the rule which take effect prior to this rule commencing, including changes related to: the *Integrating energy storage systems into the NEM Rule 2021* — which commences 3 June 2024.

15 **Timeframes for consultation**

16 This paper has been published to consult on a revised process for the frequency performance payments process set out in the draft rule. Submissions in response to this paper should be provided to the AEMC by **16 June 2022**.

17 The Commission plans to publish a final determination and final rule for this rule change by 7 July 2022. We will consider the best approach to finalise this rule change request in a timely manner following stakeholder consultation. Given the complexity of the issues covered by the rule change request, the current date for the final determination may need to be extended.

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1 INTRODUCTION

This chapter provides an overview of:

- the purpose of this directions paper.
- the process for making a submission
- the structure of this paper.

1.1 This paper describes a revised frequency performance payments process

This paper describes a revised process for new frequency performance payments arrangements that reward plant behaviour that helps to reduce deviation of power system frequency and allocate costs to plant that contribute to increasing frequency deviations. It builds on the Commission's draft determination for AEMO's rule change request, *Primary frequency response incentive arrangements,* published on 16 September 2021.[1]

That draft determination had four key components:

- confirmation of the mandatory primary frequency response (PFR) arrangements, as enduring beyond the sunset date on 4 June 2023 i.e. going forward all scheduled and semi scheduled generators would be required to provide primary frequency response
- introduction of incentives, through frequency performance payments, for market participants to operate their plant in a way that helps to control power system frequency
- improvements to the cost recovery for regulation FCAS by making them more transparent and better aligning incentives with the real time need for frequency control
- additional reporting requirements for AEMO and the AER in relation to frequency performance and the costs of frequency performance payments.

The performance-based arrangements are intended to align the economic incentives in the NEM with the operational goals for control of power system frequency through the real-time balancing of generation and demand. They are designed to complement and operate alongside the arrangements for Mandatory PFR as described in the draft determination. These arrangements would help to efficiently manage system frequency during normal operation on an enduring basis, allowing the system to be securely and reliably operated in a cost-effective way for consumers.

Stakeholder feedback to the commented on the frequency performance payments and arrangements for the recovery of costs for regulation FCAS - which are the subject of this paper. This paper does not discuss in detail the other two key elements of the draft determination, related to mandatory PFR and reporting requirements.The Commission acknowledges stakeholder feedback to the draft determination expressing concern for the proposed confirmation of Mandatory PFR as part of the enduring PFR arrangements in the

1 Draft determination and rule change request available on project web page: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

NEM. The Commission will further consider and respond to stakeholder feedback on this element of the draft rule in the upcoming final determination.

In response to the draft determination, stakeholders expressed broad support for an extension of the consultation process for this rule change to allow for further development of the frequency performance payments process and related analysis. The Commission accepted this feedback, approved the extension of the consultation period and engaged IES Consulting to undertake detailed analysis of the frequency performance payments process. A report on the IES analysis is published alongside this directions paper on the project web page.

The revised frequency performance payments process presented in this paper has been informed by stakeholder feedback and detailed analysis provided by IES. Revised rule drafting setting out the revised Frequency performance payments process is included in appendix D. The changes are shown in a modified version of the NER that incorporates, where relevant, final rules made by 19 May 2022 which take effect as of October 2024. This includes changes made to the NER through the *Integrating energy storage systems into the NEM Rule 2021* (commences 3 June 2024).

The Commission is seeking stakeholder comment on this revised process and the revised rule drafting included in appendix D.

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 final determination. Submissions are due **16 June 2022**.

The AEMC also welcomes individual meetings with interested stakeholders. Those wishing to meet with the AEMC in relation to this rule change should contact Ben Hiron on (02) 8296 7855 or ben.hiron@aemc.gov.au.

1.2.1 Next steps

The current statutory time frame for this rule change is for a final determination to be made by 7 July 2022. The Commission will consider the best approach to finalise this rule change request in a timely manner following stakeholder consultation. Given the complexity of the issues covered by the rule change request, the current date for the final determination may need to be extended.

1.3 Structure of this document

The remainder of this directions paper is structured as follows:

- Chapter 2 describes the assessment framework for this rule change.
- Chapter 3 provides an overview of the proposed changes to the draft rule, described in this paper.
- Chapter 4 sets out the Commission's views and analysis on the revised frequency performance payments process

2 ASSESSMENT FRAMEWORK

This section 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 as well as other documents in this process published since that time.

2.1 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).[2] This is the decision-making framework that the Commission must apply.

The NEO is:[3]

> 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.

2.2 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:

2 Section 88 of the NEL.

3 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.

2.3 Principles for assessment

The Commission is applying the following principles in its assessment of this rule change:

- **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.
- **Implementation costs:** Regulatory change typically comes with some implementation costs for regulators, the market operator and/or market participants. These costs are ultimately borne by consumers. The cost of implementation should be factored into the overall assessment of any change.

3 THE COMMISSION IS RESPONDING TO FEEDBACK ON THE DRAFT RULE

In response to stakeholder feedback on the draft rule, the Commission has undertaken additional analysis and has developed a revised rule which includes a revised frequency performance payments process to incentivise plant behaviour that helps to control power system frequency. This chapter provides an overview of:

- The key elements of the draft rule - set out in section 3.1.
- Stakeholder feedback on the draft rule - set out in section 3.2
- The analysis undertaken by IES on the frequency performance payments process - described in section 3.3.

3.1 Overview of the draft rule

The draft rule included the following key elements:

- **Confirmation that the mandatory PFR arrangements** would endure beyond 4 June 2023.

  This draft rule would revoke Schedule 2 of the *National Electricity Amendment (Mandatory primary frequency response)* rule which would have ended the existing Mandatory PFR arrangement on 4 June 2023. This would mean that all scheduled and semi-scheduled generators would continue to be required to support the secure operation of the power system by responding automatically to changes in power system frequency.

- **Reforms to the causer pays process** for the allocation of regulation FCAS costs to deliver improved valuation and pricing of plant behaviour that impacts on power system frequency.

  These changes would include the introduction of frequency performance payments to value positive contributions, the shortening and alignment of the sample and application periods for the determination of participant contribution factors, and further changes to improve the transparency of the causer pays process. These changes would be expected to better align the economic incentives for plant active power performance, with the impact of that behaviour on the need for corrective action through the deployment of regulation services to rebalance supply and demand and restore power system frequency to 50Hz. Incentivising the provision of primary frequency response is expected to lead to more efficient operation of the power system by encouraging all market participants to operate their plant in a way that helps to control power system frequency and optimises the use of regulation services.

- **New reporting obligations for AEMO and the AER** in relation to the levels of aggregate frequency responsiveness in the power system and the costs of frequency performance payments. This change would support the principle of transparency and would provide relevant information to market participants and stakeholders to assess the effectiveness and efficiency of the frequency control frameworks over time.

- **Implementation and transitional arrangements** for the new Causer pays process which would provide a transparent timeline for the implementation of the related changes while allowing sufficient time for AEMO to consult on the frequency contribution factors procedure and make the related changes to its internal processes and systems.

  The Commission also proposed to amend the existing date for the publication of the final *Primary frequency response requirements* document (*PFRR*), which AEMO is currently required to complete by 6 December 2021 to be a date which is 6 months from the date that the final rule is made, in order to allow time for AEMO to consult on the final *PFRR* that will apply under the enduring arrangements.

Further detail on each of these elements is available in the draft determination, *Primary frequency response incentive arrangements*, published on 16 September 2021.

This Directions paper provides further detail on a revised frequency performance payments process that builds on the proposed reforms to causer pays set out in the draft determination.

3.2 Stakeholder responses to the draft determination

The Commission received 22 submissions in response to the draft determination. This section provides an overview of key themes raised in these submissions across the following subject areas:

- Mandatory PFR — covered in section 3.2.1
- Frequency performance payments and regulation FCAS costs recovery — covered in section 3.2.2
- Additional reporting requirements for AEMO and the AER — covered in section 3.2.3

This directions paper is focused on responding to stakeholder feedback on the frequency performance payments process and the arrangements for the allocation of regulation costs. The Commission will respond to stakeholder feedback on other issues in its final determination.

3.2.1 Stakeholder views on Mandatory PFR

There was a broad range of stakeholder views expressed in response to the confirmation through the draft rule of the narrow band Mandatory PFR arrangements. There was a general acceptance of the improved system frequency performance as a consequence of the re-introduction of narrow band mandatory PFR. However, many stakeholders — particularly generator representatives — expressed opposition to the confirmation of Mandatory PFR as an enduring arrangement.[4] These stakeholders would prefer that the mandatory PFR arrangement be relaxed or removed and that alternative or complementary market or incentive arrangements be put in place to provide narrow band PFR.

4 For example, submissions to the draft determination: AEC; AGL; Alinta Energy; Delta Electricity; ENGIE; Fluence; Iberdrola; Shell Energy; Snowy Hydro; Stanwell corporation.

At the same time, a number of stakeholders recognised the system security and resilience benefit provided by narrow band mandatory PFR and expressed support for its confirmation as an enduring requirement for scheduled and semi-scheduled generators in the NEM.[5]

The Commission acknowledges stakeholder feedback to the draft determination expressing concern for the proposed confirmation of Mandatory PFR as part of the enduring PFR arrangements in the NEM. The Commission will further consider and respond to stakeholder feedback on this element of the draft rule in the upcoming final determination and notes that this element of the draft rule is not the focus of this directions paper.

3.2.2 Stakeholder views on frequency performance payments and regulation FCAS costs recovery

Most stakeholders expressed support for the development and implementation of performance-based incentive arrangements to recognise the value provided by frequency responsive plant.[6] However, many stakeholders were concerned by what they considered to be a lack of detail on the proposal for frequency performance payments set out in the draft rule and described in the draft determination.[7] These stakeholders were concerned that arrangements set out in the draft rule were ill-defined and would not adequately value helpful active power response to encourage efficient operational and investment outcomes for PFR over the long term. In particular stakeholders requested more detail on:

- The strength and scaling of frequency performance payments
- The process for allocation of costs for regulation services that are not used within a trading interval.

The AEC, and its members, suggested that the development of a frequency performance payments process should be more closely aligned with the version of double-sided causer pays being developed by IES with support from ARENA and the AEC.[8]

A number of stakeholders requested that the Commission extend the time for assessment of the rule change to allow for further analysis and stakeholder consultation.[9] These stakeholders proposed that additional time would allow for the details of the frequency performance payments process, and the related cash flows, to be worked through with AEMO, which would provide stakeholders with greater confidence that the final rule will be fit for purpose over the long term.

3.2.3 Stakeholder views on additional reporting requirements

Stakeholders responses to the draft rule were generally supportive of the proposed additional reporting requirements for AEMO in relation to frequency responsiveness. Stakeholders were

5 For example, submissions to the draft determination: AEMO; Hydro Tasmania; Tesla; SA Dept. of Energy and mining.

6 For example, Submissions to the draft determination: AEMO, p.1. ; AGL, ; ARENA, p.1.; CS Energy, p.3.; Energy Australia, p.2.; ENGIE, p.2. ; Hydro Tasmania, p.2. ;Iberdrola, p.1. ; SA Dept of Energy and Mining, p.2.

7 For example, Submissions to the draft determination: Clean energy council, p.3; Energy Australia, p.3.; ENGIE, p.2.; Iberdrola, pp.15-16.; Snowy Hydro, pp.4-5.

8 For example, Submissions to the draft determination: AGL, p.2.; CS Energy, pp.3,11.

9 For example, Submissions to the draft determination: AEC, AEMO, AGL, Alinta, CEC, CS Energy, ENGIE, Hydro Tasmania, Iberdrola, Origin.

also supportive of the additional reporting requirements for the AER in relation to the costs associated with frequency performance payments.[10]

A number of stakeholders, including Snowy Hydro and Shell Energy, proposed that AEMO also be required to report on other metrics related to PFR, including available stored energy within the generation fleet, to gauge the capacity to provide effective active power frequency response.[11]

3.3 Frequency performance payments analysis provided by IES

In response to stakeholder feedback on the draft determination, the Commission engaged Intelligent Energy System(IES) to undertake detailed analysis of the frequency performance payments process. This engagement was able to leverage the previous work that IES has undertaken in the area of frequency deviation pricing, including the Australian Energy Council — Double sided causer pays study, supported by ARENA which concluded in February 2022.[12]

The objectives for the IES analysis were to:

- Investigate a range of alternative approaches for the implementation of frequency deviation pricing building off the frequency performance payments process set out in the draft rule.
- Develop a number of scenarios covering potentially viable options for the implementation of frequency performance payments. A scenario is a combination of options for elements of the frequency performance payments process that together constitute a viable system to incentivise good frequency control.
- Develop a database algorithm to calculate contribution factors and settlement results for these scenarios based on causer pays data for the period 1 Feb 2021 to 31 Dec 2021.

The goal of this analysis was to demonstrate the viability and financial implications associated with different frequency performance payment approaches.

The IES report, *Frequency performance payments analysis*, is published alongside this directions paper on the project web page.[13] The IES report covers the following:

- The methodology for the analysis, including the process for the development of scenarios for different applications of frequency performance payments.
- The findings from IES's initial investigations of different approaches to key elements of the frequency performance payments process including:
  - Aggregation of contribution factors at the unit or portfolio level, as discussed in section 4.1.1 of this paper
  - The system performance metric — which measures the system need for positive or negative active power deviations to help balance and correct deviations in power

10 For example, Submissions to the draft determination: AEMO, p.1.; AGL, p.3.; ENGIE, p.2.; SA Dept. or Energy and Mining, p.1.; Snowy Hydro, p.5.

11 Submissions to the draft determination: Shell Energy, p.10.; Snowy Hydro, p.5.

12 AEC Double sided Causer pays study reports are available at: https://arena.gov.au/projects/australian-energy-council-double-sided-causer-pays-study/

13 Refer to: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

    system frequency. This relates to the measure of the need to raise or lower the frequency of the power system, discussed in section 4.1.2 of this paper.
  - The unit reference trajectory - which describes the expected — baseline — performance for the relevant plant over the trading interval. This concept is also discussed in section 4.1.3 of this paper.
  - Financial weighting and scaling of unit contributions, as discussed in section 4.2.2 and section 4.2.3 of this paper.
  - Potential approaches to the allocation of costs for enablement of regulation services, related to section 4.3 of this paper.
- Results from a short period analysis based on two weeks of sample data commencing on 6 September 2021. This includes:
  - Contribution factors and raw settlement results based on four potential system performance metrics:[14]
    - Scenario 1: Frequency Indicator (FI) - this is the system metric used by AEMO in the current causer pays process, it measures the need for regulation services in MW, based on the AGC control objectives.
    - Scenario 2: Smoothed Hertz - this is a smoothed measure of system frequency.
    - Scenario 3: Combined Hertz - this is a combination of raw frequency and smoothed frequency.
    - Scenario 4: Gross dispatch error - this is the sum of active power deviations from all plant with appropriate metering.
  - Adjusted settlement results based on the contribution factors developed through scenario 3 - combined Hertz, to investigate three different approaches to scaling the frequency performance payments.
    - Scaling by Gross dispatch error (Scenario 3.8)
    - Scaling relative to raw contribution factors valued at a reference frequency (Scenario 3.14: Hz spread scaling)
    - Scaling by Gross dispatch error, with the regulation component included in the reference trajectory (Scenario 3.15)
- Results from the long period analysis to validate the settlement outcomes based on 11 months of sample data from 1 Feb 2021 to 26 Dec 2021. The long period analysis focused on the three different scaling approaches developed through the short period analysis: Scenario 3.8, 3.14, and 3.15.

The results from the IES analysis inform the policy decisions reflected in the revised rule and discussed in chapter 4. The high-level findings in relation to the expected financial impacts associated with the frequency performance payments process are summarised and discussed in section 4.2.4.

14 These system metrics are described in more detail in section 4.1.2 of this paper and in section 3.3 of the IES report, *Frequency performance payments analysis*, published on the project web page.

4 THE REVISED FREQUENCY PERFORMANCE PAYMENTS PROCESS

The Commission is proposing changes to the elements of the draft rule related to the reform of the existing causer pays arrangements for the allocation of regulation FCAS costs and the new frequency performance payments process. The Commission acknowledges stakeholder feedback that the frequency performance process set out in the draft rule did not provide sufficient clarity in relation to how the proposed process would work in practice, including the valuation of helpful active power behaviour. This paper includes a revised rule, in appendix D, which sets out a revised frequency performance payments process.

Supported by the analysis outlined in IES's report, *Frequency performance payments analysis*, the revised process is intended to measure and value all active power deviations, relative to the expected active power trajectory for each identifiable unit of generation or load. The deviations would be priced at the respective price for raise or lower regulation services, based on the system requirement for raise or lower response.

The frequency payments process proposed under the revised rule is similar to that set out in the draft rule. The revised arrangements would maintain the key elements of the draft rule, including that:

- AEMO would prepare a **frequency contribution factors procedure** that describes the process for determining contribution factors. The contribution factors reflect the impact of power system equipment (generation and load) on system frequency. A positive contribution factor represents plant behaviour that helps to control system frequency and reduce a frequency deviation (from 50Hz). A negative contribution factor represents plant behaviour that contributes to the deviation of system frequency.
- **Frequency performance payments** would be made to market participants who obtain positive contribution factors in a trading interval. The **costs of frequency performance payments** would be allocated to market participants who obtain negative contribution factors for that trading interval.
- The **costs for regulation services** would be allocated to market participants who obtain negative contribution factors and therefore cause the need for these services.

However, in response to stakeholder feedback on this element of the draft rule, we have made a number of changes and refinements to the design of each of these key elements. We have also sought to provide more practical explanation of how these might operate in practice – informed by the IES modelling. The following sections describe the revised frequency performance process in further detail, focused on the three key elements.

- Section 4.1 describes the requirements and guiding principles related to the frequency contribution factors procedure.
- Section 4.2 describes the frequency performance payments transactions.
- Section 4.3 describes the process for the allocation of costs for the enablement of regulation services.

4.1 Frequency contribution factors

A summary of the elements of the revised rule that relate to the determination of frequency contribution factors is provided in Table 4.1. Further detail on the reasoning for the changes to the draft rule is provided in the following sub-sections.

- Section 4.1.1 describes the requirements that apply to AEMO for the development of the frequency contribution factors procedure to calculate contribution factors.
- Section 4.1.2 describes the provisions in the revised rule in relation to the measure of the need to raise or lower the frequency of the power system.
- Section 4.1.3 describes the arrangements for the definition of a reference trajectory that provides a baseline of expected plant behaviour with respect to the generation or consumption of energy during each trading interval.
- Section 4.1.4 describes regional considerations including the arrangements to manage asynchronous operation of Tasmania and islanded regions following separation events.
- Section 4.1.5 describes the requirements under the revised rule in relation to the collection and publication of data related to frequency contribution factors.

Table 4.1: Frequency contribution factors — Revised approach

ELEMENT	DRAFT RULE	REVISED RULE	REASONING
Contribution factor objective	The contribution factor reflects the contribution to the need for, or reduction in the need for, the regulating raise (or regulating lower) service.	**Change to the draft rule** The contribution factor reflects the contribution to the aggregate deviation in *frequency* of the *power system.*	The new description of the objective for the contribution factors provides a closer linkage with the frequency of the power system and removes the reference to regulation services. Refer to section 4.1.1 for further detail.
Unit aggregation	Contribution factors determined for each market participant based on the aggregate of all plant within their portfolio.	**Change to the draft rule.** Contribution factors determined separately for each eligible unit (DUID) registered generation and load.	Unit contribution factors will avoid distortions due to portfolio aggregation. AEMO already calculates unit factors through the existing causer pays procedure, therefore implementation will be straightforward. Refer to section 4.1.1 for further detail.
Raise/lower categorisation	Separate contribution factors to be determined with respect to the need for raise and lower response.	**As for the draft rule**	The determination of separate contribution factors with respect to raise and lower response enables each type of behaviour to be valued relative to the respective price for raise or lower response. This reflects the different price signals provided by the market for raise and lower regulation services. Refer to section 4.1.1 for further detail.

ELEMENT	DRAFT RULE	REVISED RULE	REASONING
Timing of sample and application periods.	Contribution factors for a trading interval to be determined based on data sampled from the same trading interval, where it is practical to do so.	**As for the draft rule**	There was general stakeholder support for the alignment of the sample and application periods over a single trading interval. Refer to section 4.1.1 for further detail.
Default contribution factors	No requirement in the draft rule.	**New in the revised rule** The procedure must include the method AEMO will use to determine a default contribution factor to be used: • where it is impractical to determine a contribution factor for a unit in a trading interval based on data measured for that trading interval. • for the allocation of costs of regulation services - not used.	The proposed addition clarifies AEMO's responsibility to establish a method used to determine default contribution factors. Refer to section 4.1.1 for further detail.
The system frequency metric	The procedure must include a formula to describe the objective for controlling power system frequency.	**Similar to the draft rule** The procedure must include a formula (based on system frequency) to be used to calculate measure of the need to raise or lower the *frequency* of the *power system.*	This requirement is intended to provide market participants with transparency in relation to how the plant performance will be measured. It provides guidance and flexibility for AEMO in relation to how the system frequency metric is specified in the frequency contribution factor procedure. Refer to section 4.1.2 for further detail.

ELEMENT	DRAFT RULE	REVISED RULE	REASONING
Reference trajectory	The procedure must describe the method used to determine a reference trajectory for plant that has appropriate metering. This must be informed by: • the dispatch target(level) for scheduled (semi-scheduled) plant. • Information provided by non-scheduled market participants. It may be informed by the regulation component for enabled units.	**Similar to the draft rule** Under the revised rule, AEMO would only be required to include information provided by non-scheduled market participants where it is practical to do so.	The revised rule allows for the frequency performance payments process to be coordinated and align with the process for supply/demand forecasts that input to NEMDE; as noted in AEMO's submission to the draft determination.[1] Refer to section 4.1.3 for further detail.
Treatment of asynchronous regions (including Tasmania)	AEMO must determine contribution factors to apply in a region during asynchronous operation.	**Change to the draft rule** AEMO must determine contribution factors based on the power system frequency measured in each NEM region (where practical).	The reference to regional frequency is intended to support the development of a process where the economic incentives align with operational objectives following islanding of a NEM region and for the operation of the Tasmanian region. At the same time, AEMO may set out an alternative process for situations where it is not practical to use regional frequency. Refer to section 4.1.4 for further detail.
Data collection	No requirement in the draft rule.	**New in the revised rule** AEMO's procedure must specify the data that	This requirement will provide improved transparency in relation to data collected to support the determination of

ELEMENT	DRAFT RULE	REVISED RULE	REASONING
		AEMO will use to determine contribution factors. The relevant data must include active power output or consumption and may include local frequency, electronic signals received from AEMO and any other data AEMO considers relevant.	contribution factors. It will support further consideration through AEMO's consultation on the frequency contribution factor procedure in relation to the practicality of including additional local data fields. Refer to section 4.1.5 for further detail.
Publication of relevant data	AEMO must publish as soon as is practicable after the relevant trading interval: • contribution factors • data related to the objective for controlling power system frequency. and must publish: • historical data used to determine contribution factors in accordance with the timetable for provision of market information • any parameters related to the objective for controlling power system frequency, at least 5 business days prior to their application.	**Similar to the draft rule** AEMO must publish as soon as is practicable after the relevant trading interval: • contribution factors • data related to the measure of the need to raise or lower the power system frequency. and must publish: • default contribution factors at least 5 days before the period in which they will apply. • any parameters related to the measure of the need to raise or lower the frequency of the power system, at least 5 business days prior to their application. • historical data used to determine contribution factors in accordance with the timetable for provision of market information	The revised rule more clearly describes the data publication requirements for AEMO, in relation to the frequency contribution factors procedure. It also includes an additional requirement for AEMO to publish default contribution factors at least 5 days before the billing period in which they will apply. These data publication requirements are intended to provide increased transparency to market participants. Refer to section 4.1.2 for further detail.

Note: 1. AEMO, Submission to the draft determination, 2 November 2021, p.8.

4.1.1 Contribution factors for each unit of generation or load

A key element of the revised frequency performance payments process is the determination of contribution factors that reflect the contribution of power system plant, generation and load, to the deviation of system frequency. The revised process is similar to that set out in the draft rule, which in turn builds off the existing — Causer pays — arrangements for the allocation of costs for regulation services.

The following attributes of the contribution factors are maintained in the revised rule:

- Separate contribution factors would be determined with respect to the need to raise or lower the frequency of the power system.
- Contribution factors would be determined for a trading interval, based on measurement of plant and system performance during the same trading interval — where it is practical to do so.

The revised rule differs from the draft rule in relation to three key areas:

- The objective for a contribution factor is linked to the impact on system frequency, not the need for regulation services.
- Contribution factors would be determined for each eligible unit of generation or load, not for an entire portfolio of plant operated by a Market participant. Consistent with stakeholder feedback on the draft rule, Demand response service providers and Market network service providers would be excluded from the processes for frequency performance payments and allocation of regulation FCAS costs.
- AEMO would be required to set out a methodology to determine default contribution factors to apply when it is not practical to use performance data measured for the same trading interval.

The reasoning for each of these changes is provided below.

The contribution factor reflects the impact of plant performance on system frequency

Under the revised rule a contribution factor reflects the extent to which an eligible unit contributes to cause or reduce the deviation of power system frequency. Positive performance is defined as plant behaviour that contributes to a reduction in the deviation of power system frequency. A negative contribution reflects that the unit caused an increase in the deviation of power system frequency.

This objective of measuring positive and negative contributions is similar to that set out in the draft rule, however, the revised objective no longer refers to the contribution to the need for regulation services.

This change clarifies that the measurement of unit performance is based on the impact on power system frequency, and not directly on the need for regulation services. While the two are closely aligned, the need for regulation service includes consideration of the function and control objectives for AEMO's AGC system, which may not be transparent, and need not be transparent to market participants. The revised objective for a contribution factor, coupled with the revised provisions for the measure of the need to raise or lower power system frequency, are intended to improve transparency in relation to what constitutes positive plant performance. Positive performance is defined as plant behaviour that contributes to reduce the deviation of power system frequency.

Contribution factors apply for individual registered units of generation and load

Under the revised rule, individual contribution factors would be determined for each eligible unit, not for each Market participant, as set out under the draft rule. This change is supported by the Frequency performance payment analysis undertaken by IES and will result in a consistent application of the deviation pricing theory.

The aggregation of plant performance to the portfolio level would not be expected to drive any materially different outcomes for the frequency performance payments, as these payments equally value positive and negative performance. However, portfolio aggregation would favour large portfolios for the allocation of regulation costs, as negative unit contributions factor can be offset by positive performance, resulting in a lower net allocation of costs over the entire portfolio.

Portfolio aggregation has some benefits under the current one-sided causer pays arrangements, as it creates a partial incentive for helpful plant behaviour within a generation portfolio. However, the frequency performance payments process creates a universal mechanism to value helpful response, as such portfolio aggregation is no longer necessary and actually distorts the economic signals for power system plant. The Commission considers that the economic incentives for power system plant should ideally not be impacted by administrative affects, like portfolio aggregation. Therefore, the contribution factors under the revised rule apply for each registered unit.

The revised rule introduces the term ‘ eligible unit’ to describe a unit which would obtain a frequency contribution factor. The following plant are included under the term ‘eligible unit’:[15]

- a scheduled generating unit
- a semi-scheduled generating unit
- a scheduled bidirectional unit
- a scheduled load
- a market connection point (for customer load)
- an ancillary service unit
- a non-scheduled generating unit
- a non-scheduled bidirectional unit
- a non-scheduled load.

15 This list of plant reflects the drafting under the NER following the implementation of the *Integrating energy storage systems into the NEM Rule 2021*, from 3 June 2024.

Included and excluded market participants

Under the draft rule, contribution factors would have been determined for each market participant including a Market generator, market customer, Market small generation aggregator, Demand response service provider or Market network service provider. The revised rule maintains the link to plant operated by a Market generator, market customer, Market small generation aggregator but deletes any reference to plant operated by a Demand response service provider (DRSP) or Market network service provider (MNSP).

The removal of the reference to plant operated by a DRSP is consistent with feedback provided by Enel X in response to the draft determination that DRSP's should not be included in the frequency performance payments process, as the allocation of non-energy costs to DRSP's should ideally be considered through a future review of the wholesale demand response mechanism.[16] This change is also consistent with the final determination for the *Integrating energy storage systems into the NEM rule change*, which did not include DRSP's under the new category of Cost recovery market participant for the allocation of non-energy costs.[17]

The revised rule also excludes MNSP's from the frequency performance payments process and allocation of regulation FCAS costs. This exclusion is consistent with the views of AEMO and Hydro Tasmania that Basslink, which is currently the only registered MNSP in the NEM, should not be included in the frequency performance payments transactions.[18] This view is based on control philosophy for Basslink which mimics an AC Interconnector and does not have the ability to correct frequency to 50Hz in either Tasmania or the mainland NEM. Rather, the Basslink frequency controller operates to link the frequency in Tasmania to that in the Mainland subject to a control function based on the frequency in each region and the direction and magnitude of power flow through the DC interconnector.

AEMO to set out the method for determining default contribution factors

The revised rule includes additional provisions that require AEMO to set out its method to determine default contribution factors. These default contribution factors would be determined and published in advance of application, similar to the existing process for regulation contribution factors. The draft rule sets out that these default contribution factors would apply under the following situations:

- Where it is not practical for AEMO to determine a contribution factor for an eligible unit based on data measured for the same trading interval.
- For the allocation of costs for regulation services that were not used by AEMO in the relevant trading interval. The approach to the allocation of costs for regulation services is described further in section 4.3.

This approach to the determination of default factors is consistent with AEMO's submission to the draft determination, suggesting that there was an opportunity to revise the draft rule to

16 Enel X, Submission to the draft determination, 1 November 2021.

17 AEMC, *Integrating energy storage systems rule into the NEM - Final determination, 2 December 2021, p.48.*

18 Submissions to the draft determination: AEMO, p.8., Hydro Tasmania, pp.2-4.

consolidate and clarify the arrangements for "back-up" factors and the allocation of costs for regulation services not-used.[19]

As discussed in section 4.1.5, AEMO would be required to publish the default contribution factors 5 days in advance of the billing period in which they will apply.

4.1.2 The measure of the need to raise or lower system frequency

In order to assess whether the active power deviations of an eligible unit are causing or reducing the aggregate deviation in the frequency of the power system, AEMO must compare plant active power deviations against the need to raise or lower power system frequency.

In simple terms, the deviation of power system frequency from the target of 50Hz is a measure of the need to raise or lower the frequency of the power system. However, in practice it may be appropriate for this metric to incorporate additional elements based on different time constants.[20] In order to provide market participants with a transparent view on this system metric, the revised rule includes provisions for AEMO to define a formula, based on system frequency, used to calculate the system performance metric for the purposes of determining contribution factors.

Development of a formula to determine the need for corrective response

The draft rule included new provisions intended to provide market participants with increased transparency in relation to the type of behaviour that would be rewarded or penalised under the frequency performance payments process. The draft rule included the requirement under cl 3.15.6A that:

> (k1) AEMO must define in the frequency contribution factors procedure a formula that AEMO will use in each trading interval to describe its objective for controlling the power system frequency. The formula must be defined in sufficient detail so that a Market Participant can use it to estimate the need for regulation services in each trading interval, and may include parameters to be determined by AEMO from time to time to be applied to the different elements of the formula.

This requirement was intended to provide AEMO with a degree of flexibility as to how it defined the 'objective for the control of power system frequency', while also providing a formula that market participants could use to estimate the system frequency metric that AEMO would use to determine contribution factors.

The revised rule maintains the policy intent from the draft rule, however the drafting is revised to provide improved clarity on the key components of the formula, including an explicit link to power system frequency to avoid doubt. The relevant drafting under the revised rule in cl 3.15.6AA includes:

> (g) *AEMO* must define in the *frequency contribution factors procedure:*

19 AEMO, Submission to the draft determination, 2 November 2021, pp.7-8.

20 IES, *A double-sided causer pays implementation of frequency deviation pricing – A project sponsored by the Australian energy council*, 4 February 2022, p.14-15.

(2) a formula that *AEMO* will use in each *trading interval* to calculate the measure of the need to raise or lower the *frequency* of the *power system*, in order to determine a contribution factor under paragraph (e), which:

(i) must be based on *power system frequency*;

(ii) must contain sufficient detail so that a *Cost Recovery Market Participant* can use it to estimate the need to raise or lower the *frequency* of the *power system* during each *trading interval*; and

(iii) may include parameters to be determined by *AEMO* from time to time to be applied to the different elements of the formula;

Defining a system performance metric

The system performance metric was a key focus of the IES analysis, which investigated a number of potential approaches for this element of the frequency performance payments process. The goal of these investigations was to identify a system frequency metric that provided a transparent and consistent measure of the need to raise or lower the frequency of the power system. [21] The IES analysis investigated the feasibility of potential system performance metrics based on system frequency and based on dispatch error.

Frequency based system performance metrics

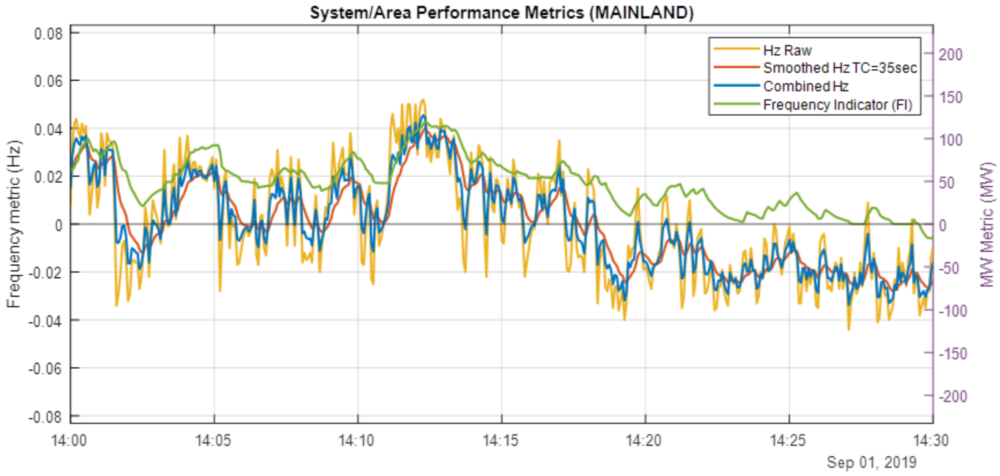
The most direct form of a 'system frequency metric' is the real-time measure of the deviation of system frequency from 50Hz. A frequency deviation below 50Hz would signal the need for additional generation output(or reduction in energy consumed) to raise the frequency of the power system, whereas a frequency deviation above 50Hz would signal the need for a decrease in generation output (or increase in energy consumed) to lower power system frequency.

Figure 4.1 shows the following frequency based metrics investigated by IES:

- raw frequency deviation (Hz) – this is a measure of the real-time, unfiltered deviation of system frequency with respect to 50Hz.
- smoothed Frequency (Hz) – this smoothed version of real-time frequency deviation. For the IES analysis, a time constant of 35 seconds was used.
- combined frequency - 1:1 combination of raw and smoothed frequency (Hz)

21 For further detail refer to section 3.3 of the IES report, *Frequency performance payments analysis,* available on the project web page.

Figure 4.1: Comparison of system frequency metrics



Source: IES, Frequency performance payments analysis, 19 May 2022.

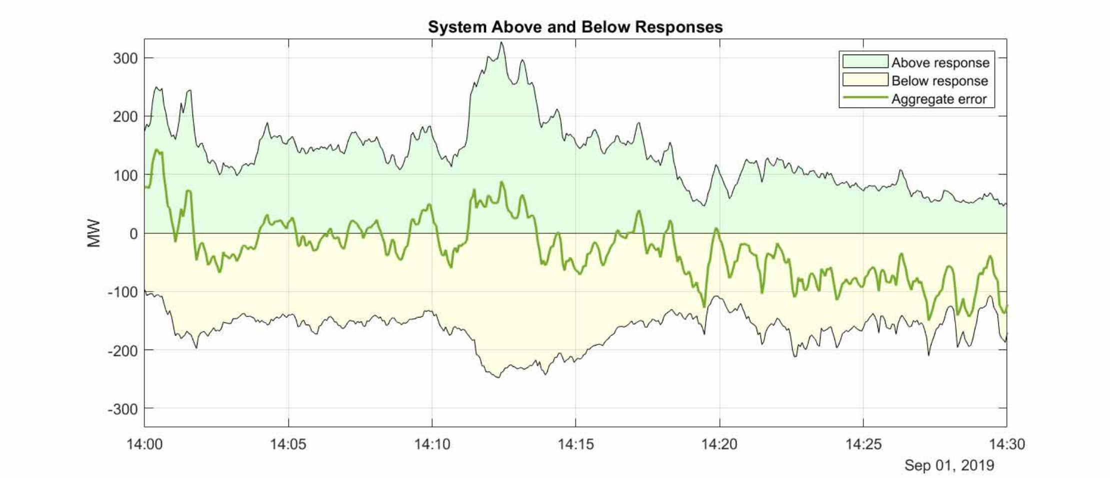
System performance metrics based on dispatch error

Dispatch error is a measure of the aggregate MW error in the power system relative to dispatch.[22] It is produced through the summation of all the individual unit deviations for plant with appropriate (SCADA) metering. The IES analysis investigated the feasibility of two metrics based on system dispatch error for use as the system metric for the purpose of determining contribution factors. These two applications of system dispatch error were:

- gross dispatch error – this was defined as the direction and size of the majority deviations for metered plant. It was put forward as a potential system metric based on the assumption that, where mandatory PFR is in effect, most plant with appropriate metering would be expected to be responding to frequency deviations in a helpful way.
- aggregate (net) dispatch error – this is the remaining unbalance MW deviation for metered plant, based on the summation or netting of under-target and over-target errors, as shown in Figure 4.7.

22 The concept of aggregate dispatch error is also used as corrective feedback to the demand forecast as input to AEMO's dispatch. Ref. AEMO, Dispatch – SO_OP_3705, 24 October 2021, p.19-20.

Figure 4.2: Dispatch error



Source: IES, Frequency performance payments analysis, 19 May 2022.

The IES analysis found that both gross and aggregate (net) dispatch error are loosely correlated with system frequency deviation, and therefore are not well suited as a performance measure to guide generator active power behaviour. At the same time, the analysis of these metrics demonstrated the true scale of active power deviations in the power system, including the scale of offsetting amongst metered plant. The IES analysis concluded that system dispatch error was not well suited as a performance metric, however it is well suited as a measure of the need for/or delivery of helpful active power response.[23]

The application of gross dispatch error as a scaling factor for the frequency performance payments is described in section 4.2.3.

Concluding remarks

The Commission considers that the frequency performance metric should be a transparent and consistent measure available in real-time to all market participants. While raw system frequency would be the most transparent and accessible option, there are drawbacks to this real-time measure, notably the volatility of the signal and the degree of misalignment with the control objective for regulation FCAS.

The preferred metric used to determine settlement amounts from the IES analysis was the combined frequency metric. This metric was selected by IES as it is based on system frequency and provides a combination of raw Hz and smoothed Hz, recognising the combined role of proportional PFR and sustained active power response to help control power system frequency.

23 For further detail refer to section 3.3 of the IES report, *Frequency performance payments analysis,* available on the project web page.

4.1.3 The reference trajectory

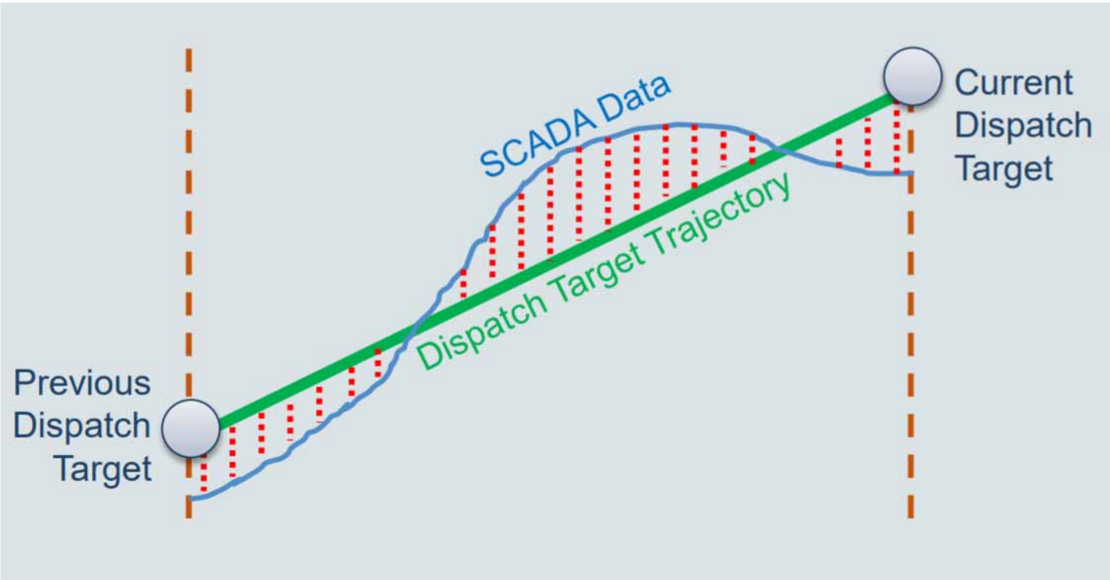
Measurement of plant performance with respect to frequency requires an active power reference trajectory against which actual plant behaviour can be compared to determine deviations from expected active power generation or consumption. To provide transparency as to how plant performance is measured, the reference trajectory must be clearly defined and understood by market participants.

The 'reference trajectory' describes the expected — baseline — performance for the relevant plant over the trading interval. The current approach to determining a reference trajectory for a scheduled or semi-scheduled generator is shown in Figure 4.3.

If a unit's active power behaviour matches this baseline, then it would receive a neutral or zero contribution factor and would not be allocated any payments or costs through the frequency performance payments process. Measured deviations from the reference trajectory determine the degree to which an eligible unit is considered to have contributed to causing or reducing the aggregate deviation of power system frequency.

AEMO currently determines and describes the reference trajectory for different categories of registered plant in the Causer pays procedure. A description of the current approach for determining a reference trajectory through the Causer pays procedure is included in section 4.2.3 of the draft determination.

Figure 4.3: **Reference trajectory for scheduled and semi-scheduled plant**



Source: AEMO, Regulation FCAS contribution factor procedure – Determination of contribution factors for regulation FCAS cost recovery, 9 November 2018, p.12.

As for the draft rule, under the revised rule AEMO must set out in the frequency contribution factors procedure the method it will use to determine a reference trajectory for each eligible unit with appropriate metering. The reference trajectory must be informed by:

- the dispatch target for scheduled generation, scheduled load, scheduled bidirectional unit and ancillary service unit
- the dispatch level for semi-scheduled generation
- where practical, information provided by a registered participant for a non-scheduled generating unit or non-scheduled bidirectional unit, that relates to its expected trajectory over the trading interval.

The reference trajectory may also be informed by other relevant information including the electronic signals from AEMO with respect to the provision of a market ancillary service, such as regulation FCAS. The revised rule provides AEMO with discretion as to how such additional information, and any other factors AEMO determines to be relevant, may inform the reference trajectory.

The revised rule differs from the draft rule through the inclusion of the words "where practical" in relation to the inclusion of self forecast information provided by a registered participant for a non-scheduled generating unit or non-scheduled bidirectional unit.

The following sub-sections discuss:

- the reasoning for the change in the revised rule in relation to the practicality of using self-forecasts as an input to the unit reference trajectory
- the potential for the reference trajectory to also be informed by electronic signals provided by AEMO in relation to a unit dispatch target or dispatch level - as discussed through the technical working group for this rule change.
- consideration in relation to the inclusion of the regulation component in the reference trajectory and the related results for the IES analysis.

Inclusion of self-forecast information for non-scheduled market participants

The draft rule included provisions for the reference trajectory to be informed by information provided by a non-scheduled market participants, that relates to its expected trajectory over the trading interval. The revised rule maintains this provision but clarifies that it would only apply, 'where practical'. This change reflects feedback from AEMO, that it would be best to integrate self-forecast information into the frequency contribution factor procedure if that information were also integrated into the supply/demand forecasts used as an input to NEMDE.[24]

The use of self forecast information to inform the reference trajectory for non-scheduled market participants aligns with and will support the expected evolution of the NEM toward greater active participation by demand side market participants, either directly or through the activity of third party aggregators. The expected evolution of the NEM towards greater demand-side participation is described in the ESB's Post 2025 Market Design under the pathway for the effective integration of DER and flexible demand and the DER Implementation Plan.[25]

24 AEMO, Submission to the Draft determination, 2 November 2021, p.8.

25 Energy Security Board, Post-2025 Market Design - Final advice to Energy Ministers - Part A, 27 July 2021, pp. 10, 14, 35 - 39.

The ESB developed a concept of 'Scheduled Lite' which would support the integration of resources that are currently not scheduled in the energy market.[26]This includes smaller generators between 5 and 30 MW and demand side resources such as C&I loads and aggregations of DER. Scheduled Lite would use a mix of lower barriers and incentives to encourage these resources to 'opt-in' to either:

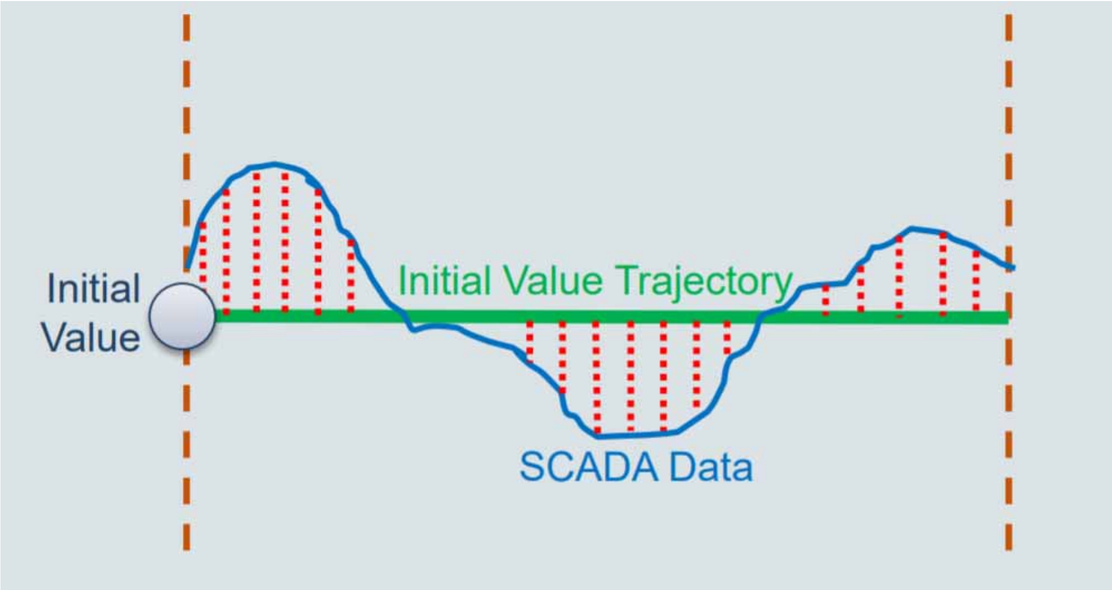
- provide greater visibility to the market operator about intentions in the market, or
- to participate in dispatch with lighter telemetry.

The frequency performance payments arrangements would provide an incentive for non-scheduled plant to opt to obtain appropriate metering to allow for the individual contribution to the aggregate deviation in frequency of the power system to be assessed. Market participants who opt to do this would not be part of the residual component of plant that does not have appropriate metering. Instead, they will receive an individual contribution factor that reflects their individual plant behaviour. The frequency performance payments process will also incentivise the provision of self-forecast information from these market participants. This will support the improvement in the accuracy of the information provided as an input to market dispatch and aligns with the objectives for the ESB DER integration and flexible demand pathway.

The current approach used to determine a reference trajectory for non-scheduled plant, with appropriate metering, is to assume that its generation or consumption will remain unchanged over the trading interval as shown in Figure 4.4. The provision of self-forecast information by non-scheduled market participants would support the development of a more accurate reference trajectory for these market participants, as compared to the default approach. However, the Commission agrees that the integration of this information into the frequency contribution factor procedure should be aligned with other changes to the market frameworks, including the integration of flexible demand through the potential future scheduled lite reforms.

26 Energy Security Board, Post-2025 Market Design - Final advice to Energy Ministers - Part B, 27 July 2021, pp.87 - 89.

Figure 4.4: Reference trajectory for non-scheduled plant (with appropriate metering)



Source: AEMO, Regulation FCAS contribution factor procedure – Determination of contribution factors for regulation FCAS cost recovery, 9 November 2018, p.13.

Relevance of electronic signals for AGC base point and the regulation component

The 5-minute target to target reference trajectory is the simplest form of a reference trajectory for scheduled and semi-scheduled plant. Scheduled and semi-scheduled generators receive their dispatch targets(levels) every 5-minutes via electronic communication with AEMO, which operates the Market dispatch for energy and ancillary services. The normal method for communicating these dispatch instructions is via electronic signals from AEMO's Automatic generation control (AGC) or the through the Energy market management system(EMMS).[27] These electronic signals relating to the dispatch trajectory are referred to as the 'unit base point'. AEMO also provides electronic signals during the 5-minute trading interval in relation to the delivery of market ancillary services such as regulation FCAS, this information is typically sent via AGC.

The draft rule made allowance for the reference trajectory to be informed by electronic signals from AEMO in relation to the provision of a market ancillary service. This provision is maintained under the revised rule.

Under both the draft rule and the revised draft rule, AEMO would not be required to use these electronic signals to inform the reference trajectory, rather it would have the option of using them it considers appropriate. This optionality reflects the Commission's understanding of practicalities and challenges related to the integration of AGC and regulation signals into the contribution factor process.

27 AEMO, Dispatch - SO_OP_3705, 1 July 2021, p.9.

Inclusion of the regulation component in the reference trajectory

The revised rule maintains the reference for the potential inclusion of the regulation component in the reference trajectory, where it is practical to do so.

Section 4.2.3 of the draft determination provided a commentary on the relevance and appropriateness of the regulation component as an input to the reference trajectory. The key points of this commentary were:

- It may be appropriate to include the regulation component in the reference trajectory as this signal is requiring a MW response from plant enabled to provide a regulation service.
- Excluding the regulation component from the reference trajectory would result in more favourable performance measurement for enabled plant with the result being that enabled plant would receive a larger share of the frequency performance payments as compared to the alternative. The provision of these payments to enabled plant would be expected to reduce the marginal cost of providing regulation services and put downward pressure on the market prices for regulation FCAS.
- Including the regulation component in the reference trajectory would result in less favourable performance measurement for enabled plant and a smaller share of frequency performance payments being provided to enabled plant as compared to the alternative. Under this approach the delivery of regulation services would be relatively separate to the measurement of plant performance with respect to frequency performance payments. Therefore, the introduction of frequency performance payments would have less impact on the market outcomes for regulation FCAS, where the regulation component is included in the reference trajectory.
- In either case, the long run combined costs for regulation enablement and frequency performance payments would be expected to be relatively similar. This outcome is expected as a result of the dynamic economic forces which would be expected to play out through market competition, noting that the fundamental costs for provision of frequency control services are unchanged.

IES analysis on the inclusion of the regulation component in the reference trajectory

The inclusion of the regulation component in the reference trajectory was investigated through the IES analysis. The results of the IES analysis for this scenario confirmed that the inclusion of the regulation component in the reference trajectory would divert frequency performance payments away from plant enabled to provide regulation services, in favour of non-enabled plant.

The preferred approach to frequency performance payments developed through the IES analysis did not include the regulation component in the reference trajectory, which would exclude regulation response. Rather, the settlement scenarios developed with IES were based on an energy balance approach that measured and valued all deviations from the reference trajectory, including regulation response. This approach used a measure of gross dispatch error to scale the frequency performance payments, accounting for the balancing effect of both PFR and regulation response. This scaling approach is described further in section 4.2.3.

The IES analysis includes an investigation of the potential inclusion of the regulation component in the reference trajectory.[28] While IES recognised the drawbacks of this approach, the final results included a scenario (3.15) to estimate the settlement impacts as a result of including the regulation component in the reference trajectory. These results showed that the overall scale of frequency performance payments was in the order of fifteen percent smaller, compared to scenario 3.8. This result showed that the scaling approach has a more dominant impact on the scale of frequency performance payments than the approach to the regulation component.

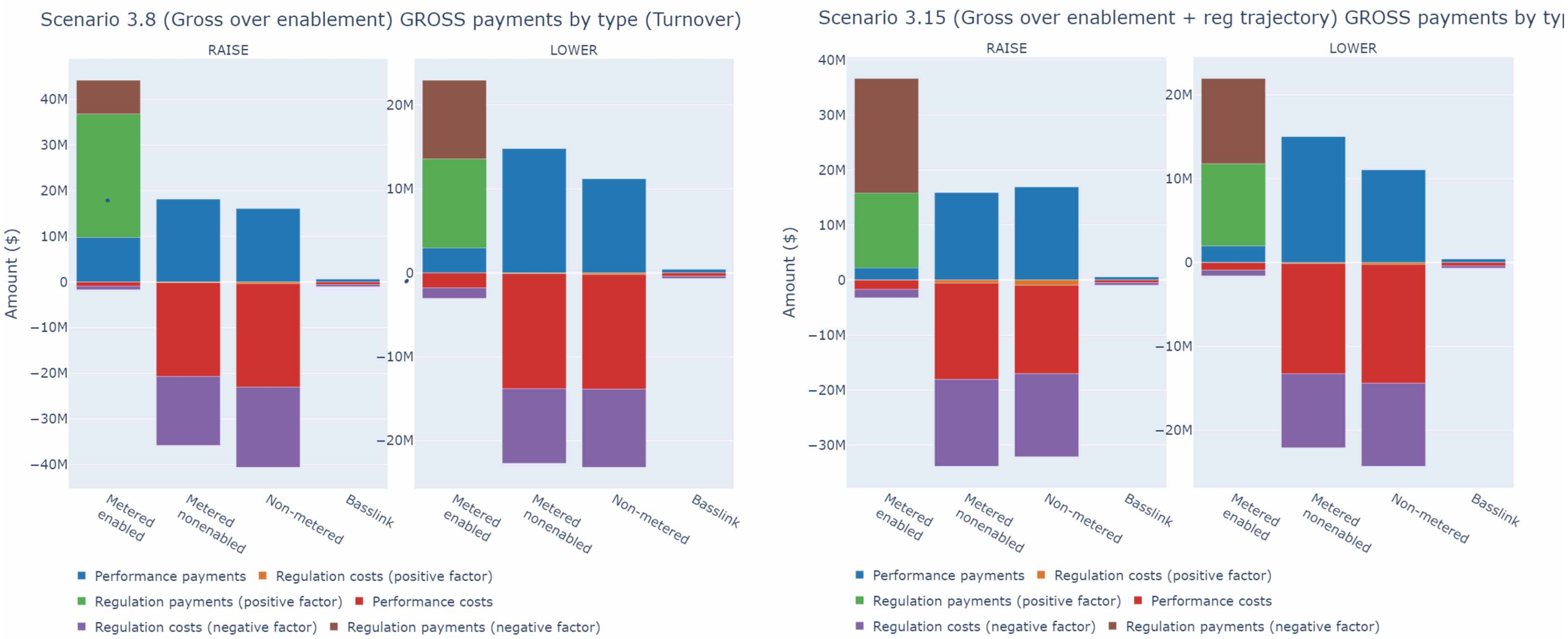
A comparison of the long period settlement results for scenario 3.8 and 3.15(regulation included in reference trajectory) from the IES analysis gives an indication of how the allocation of payments and costs is impacted by the inclusion of the regulation component in the reference trajectory. The results, shown in Figure 4.5, show the following impacts on settlement outcomes due to the inclusion of the regulation component in the reference trajectory:

- Frequency performance payments to metered-enabled units are significantly reduced for both raise and lower response.
- There are increased frequency performance payments made to non-metered or residual plant. This is more evident for payments relating to frequency raise response.
- Metered enabled units are allocated more costs for frequency performance payments and regulation enablement.

These observations are based on the performance measurement of historical plant performance and do not account for future changes in plant behaviour, including changes in response to the proposed frequency performance payments.

28 Refer to section 3.4.2 of the IES report, *Frequency performance payments analysis,* 19 May 2022.

Figure 4.5: Impact on settlement outcomes from including the regulation component in the reference trajectory



Source: IES, Frequency performance payments analysis, 19 May 2022
Note: Results from long period analysis using causer pays data from 1 Feb 2021 to 26 Dec 2021
Note: Scenario 3.8 uses a target to target reference trajectory. Scenario 3.15 includes the regulation component in the reference trajectory.

Advantages of including the regulation component in the reference trajectory

The main advantage of including the regulation component in the reference trajectory is that this would maintain a separation between the pricing and payment arrangements for PFR and the pricing and payment arrangements for regulation services.

Disadvantages of including the regulation component in the reference trajectory

The inclusion of the regulation component in the reference trajectory, would require the scaling factor to be adjusted to remove the expected regulation response. As described in section 4.2.3, the approach developed with IES would scale the frequency performance payments based on the total aggregate measure of helpful deviations in the power system, including PFR and regulation response. The intent of including the regulation component in the reference trajectory would be to separate PFR and regulation response, which would require the scaling amount to be adjusted down by the amount of regulation service called on during each trading interval. While this may be possible, to some extent, the accuracy and simplicity of the scaling factor is likely to be somewhat diminished in the process.

Another drawback of the inclusion of the regulation component in the reference trajectory, is that it does not support the recognition and valuation of regulation providers that are allocated a disproportionately large share of the aggregate regulation component. The Commission understands that the allocation of the regulation component is not necessarily uniform across enabled units. It is understood that the AGC allocates regulation component based on the ability of an enabled unit to meet the new active power target, given its starting position and operational limitations, including ramp rate limits. Therefore enabled units that respond rapidly to AGC regulation targets are more likely to be allocated additional regulation response, if the system requires it. On the other hand, enabled units that respond slowly or are subject to operational limitations would be allocated a lesser proportion of the aggregate regulation component. The exclusion of the regulation component and valuation of regulation response through the frequency performance payments would recognise and value any helpful deviation from the dispatch trajectory, whether in response to an AGC signal or due to automatic local PFR.

It is expected that the inclusion of the AGC regulation component in the reference trajectory would measure the performance of regulation units more harshly than other units, because at times this may establish a trajectory the unit is unable to do, and beyond the boundaries of the AGC "window" of operation for that unit. This is likely for units where lags are accounted for in the base point and regulation component signals. Additionally, the unit may meet its regulation signal with primary response, because AGC does not separate these, depending on certain unit control, or AGC-specific features that account for droop response, being active.

Further commentary on the implications of the potential inclusion of the regulation component in the reference trajectory is included in section 3.4.2 of the IES report.[29]

29 IES, Frequency performance payments analysis, 19 May 2022.

Concluding remarks

The Commission notes that where the regulation component is not included in the reference trajectory the regulation price would be expected to more closely match the true price for provision of PFR, as the economic signals for regulation services and PFR would be linked through the frequency performance payments. Rather than being undesirable, this outcome may lead to more accurate pricing of helpful continuous frequency response in the absence of new market arrangement to reveal the price for PFR on its own.

The revised rule maintains the reference to the potential inclusion of the regulation component in the reference trajectory. The Commission notes that there are benefits from including the regulation component as it will maintain a separation between the pricing of PFR and the pricing of regulation services. However, we also note that the IES analysis has shown that it is feasible to develop a frequency performance payments process that aggregates PFR and regulation response. We are also aware of practical difficulties such as the fact that different enabled units are relied on more than others to provide reg FCAS. The revised rule allows for AEMO to manage these practicalities through the consultation on and determination of the frequency contribution factor procedure.

4.1.4 Regional considerations

The revised rule would require AEMO, where practical, to determine contribution factors for each eligible unit based on power system frequency measured in each NEM region. This is a change to the draft rule, which would have required AEMO to determine contribution factors separately for a region that is operated asynchronously.

AEMO's submission to the draft rule requested that the reference to asynchronous operation be removed from the rule drafting, noting that asynchronous operation of NEM regions can by either permanent(as is the case for the Tasmanian region) or temporary(following the separation of part of the power system).[30] AEMO noted that:

> The current practice is for periods of temporary islanding to be ignored from the calculation of contribution factors, and to apply local factors for the island consistent with arrangements for synchronous operation.

Similarly, Hydro Tasmania noted in its submission that Tasmanian should not be treated as a separate "asynchronous island" for the purposes of frequency contribution factors and the related transactions. Hydro Tasmania expressed the view that Tasmania units should continue to receive both global and local contribution factors, reflecting their contribution to frequency control within the Tasmanian region, and the NEM more broadly, via Basslink.[31]

The Commission notes AEMO's views in relation to the infrequent nature of islanding events and the current process that ignores data for islanded regions following a separation event. However, the Commission considers that the overhaul of the Causer pays procedure and associated systems, as envisaged under the draft rule and revised rule, presents an

30 AEMO, Submission to the draft determination, 2 November 2021, pp.7-8.

31 Hydro Tasmania, Submission to the draft determination, 28 October 2021, p.4.

opportunity to incorporate locally measure frequency into the Frequency performance payments process. The inclusion of local frequency measurement is likely to be appropriate where this addition is practically achievable and under the assumption that this option does not significantly increase the cost and complexity of implementing the new process.

The main benefit of using local frequency measurements for the determination of contribution factors is the alignment of the economic incentives related to unit frequency response with the operational requirements of the power system both for system intact operation and for islanded operation following a separation event. This alignment is expected to deliver a benefit in the form of improved system resilience following separation events. These economic incentives will align with and complement the mandatory PFR arrangements that apply to scheduled and semi-scheduled generation under NER cl 4.4.2(c1).

The revised rule also allows for contribution factors for eligible units in Tasmania to be determined based on local frequency in the Tasmanian region, while also allowing for the determination of global and local contribution factors to apply with respect to the impact of plant on the local or global control of frequency.

4.1.5 Data collection and publication requirements

The determination of frequency contribution factors is reliant on the collection of data that reflects the active power behaviour of individual units of generation and load. It is also reliant on system level data such as power system frequency. The revised rule sets out a framework to guide the collection and publication of relevant data, to help provide transparency to market participants. Under the revised rule, AEMO would need to consult on, and include in its procedure, the data it will use to calculate contribution factors, including the potential role of local frequency, measured at the connection point and dispatch information, as received from AEMO. The revised rule also provides a consolidated list of data publication requirements relating to the determination of frequency contribution factors.

Data collection by AEMO

Through the technical working group discussions, stakeholders raised concerns in relation to the quality and accuracy of source data used to determine contribution factors. In particular, working group participants noted that the quality of data used to determine contribution factors can be affected by communication delays in the order of tens of seconds. These data quality issues can affect the alignment of the unit active power measurements (measured locally) with the frequency measurement (measured centrally by AEMO).

While for many units, the impact of these data quality issues is understood to be insignificant, it is also understandable that some market participants may wish to improve the quality of data used to determine their contribution factors by providing additional local data fields. These local data fields may include information such as local frequency, measured at the connection point and dispatch information, as received from AEMO.

Cl 3.15.6AA (g) of the revised rule requires that AEMO include in its procedure:

> (5) the data *AEMO* will use to calculate the contribution factor for an eligible unit with

appropriate metering, which must include the unit's *active power* output or consumption and may include:

(i) the *frequency* measured at the *connection point* for the eligible unit;

(ii) the electronic signals from *AEMO* via the *AGC* with respect to the provision of a *market ancillary service*;

(iii) Any other data AEMO considers relevant;

This provision recognises the importance of providing market participants with clarity in relation to the data collected to determine frequency contribution factors. This will assist in providing participants clear investment signals as to what data capability is required.

Data publication requirements

The revised rule provides a consolidated list of data publication requirements relating to the determination of frequency contribution factors. These requirements build on the existing requirements in the NER for AEMO to publish data related to the determination of contribution factors and the requirements set out in the draft rule.

Cl 3.15.6AA (k) of the revised rule requires AEMO to publish:

1. a default contribution factor determined under subparagraph (g)(3), at least 5 days before the *billing period* in which that contribution factor will apply;
2. any parameters it determines under paragraph (g), at least 5 *business days* prior to applying those parameters;
3. the frequency contribution factors, as soon as practicable after the relevant *trading interval*;
4. the data calculated using the formula for the system frequency metric, as soon as practicable after the *trading interval* to which it applies;
5. other data related to the determination of contribution factors for eligible units with appropriate metering in accordance with the timetable for the provision of market information[32]

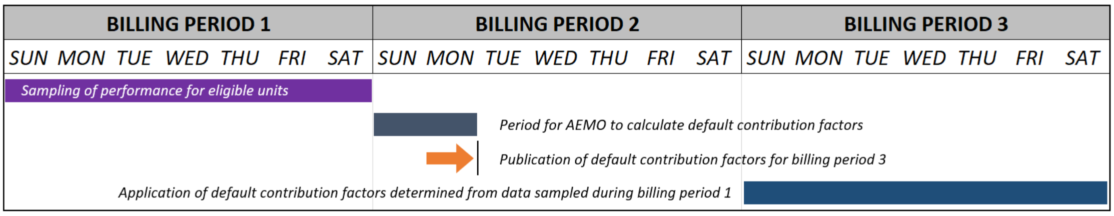
The addition to this list from the draft rule relates to the publication of a default contribution factor. The Commission proposes that these default contribution factors be published at least 5 days in advance of the billing period in which they will apply. This timing recognises that market participants should have some advance knowledge of the default contribution factors, and allows for the application of these factors to align with the settlement billing period in the NEM.[33] AEMO would be responsible for setting out the detailed methodology and timing for the determination and application of default contribution factors in its procedure.

One potential set of timing envisaged by the Commission is set out below in Figure 4.6 for information:

32 NER Cl. 3.4.3.

33 Chapter 10 of the NER defines a billing period as: The period of 7 days commencing at the start of the trading interval ending 12.05 am Sunday.

Figure 4.6: Potential timing for sampling, publication and application of default contribution factors



Source: AEMC
Note: Subject to the requirements in the final rule, AEMO would be responsible for setting out the detailed methodology and timing for the determination and application of default contribution factors in it procedure.

4.2 Frequency performance payments

The revised rule maintains the key elements presented in the draft rule to value and reward helpful active power deviations through frequency performance payments made on the basis of positive contribution factors. However, the arrangements in the revised rule that support the frequency performance payments transactions have been refined based on the investigations and analysis undertaken by IES. The resulting transactions are described by the following key formula that applies for payments and cost recoveries to eligible plant with appropriate metering for each trading interval:[34]

$$TA = CF \times \frac{P_{regulation}}{12} \times RCR$$

	where:
TA(in $)	= the *trading amount* payable or receivable by the *Cost Recovery Market Participant*;
CF (a number)	= the contribution factor for the eligible unit determined by *AEMO* for the relevant *trading interval and the region relevant to the regulating raise service or regulating lower service*
$P_{regulation}$ (in $ per MW per hour)	= the *ancillary service price* for the *regulating raise service* or *regulating lower service* in that *trading interval* for that *region*; and
RCR (in MW)	= the requirement for corrective response determined by *AEMO*

Table 4.2 provides a summary of the key elements of the frequency performance payments transactions under the revised rule, as compared to the draft rule. The estimated financial implications due to the revised frequency performance payments process are described in section 4.2.4.

34 Refer to Cl.3.15.6AA(b)(1) of the revised rule.

Table 4.2: Frequency performance payments — revised approach

ELEMENT	DRAFT RULE	REVISED RULE	REASONING
Valuation of positive performance and allocation of costs.	Frequency performance payments made to participants with positive contribution factors. Costs allocated to participants with negative contribution factors.	**As per the draft rule.**	Stakeholder submissions to the draft determination were generally supportive of the concept of valuing helpful plant behaviour through frequency performance payments and the allocation the costs of frequency performance payments to plant with negative contribution factors. However, stakeholders requested a clearer explanation of how these transactions would work to value helpful active power behaviour.
Normalisation of contribution factors	Positive contribution factors divided(normalised) by the sum of all negative contributions.	**Change to the draft rule** Positive (or negative) unit contributions are normalised by the sum of all positive (or all negative) contributions.	The revised process is based on a system-wide energy balance that is intended to measure all deviations. This approach results in positive contribution factors being equal to negative factors. As a result scaling by positive contribution factors divided by the sum of all negative contributions is not required. Refer to section 4.2.1 for further detail.
Financial weighting of frequency performance payments	Frequency performance payments weighted by the costs of regulation services (raise or lower).	**Change to the draft rule** Frequency performance payments weighted by the price of regulation services (raise or lower) in $/MW for each trading interval.	This change maintains the link to the market price for regulation services. However, this is expressed through direct reference to the regulation price, rather than the costs of regulation services. This change helps to simplify the Frequency performance payment transactions, relative to the draft rule. Refer to section 4.2.2 for further detail.

ELEMENT	DRAFT RULE	REVISED RULE	REASONING
Scaling of frequency performance payments	Frequency performance payments scaled by the ratio of regulation requirement divided by regulation enablement amount (RR/EA).	**Change to the draft rule** Frequency performance payments scaled a measure of the aggregate requirement for corrective response in MW (RCR).	The revised process scales by the aggregate requirement for corrective response. This is intended to measure and account for all helpful deviations and is a simplified version of the RR/EA term from the draft rule. Refer to section 4.2.3 for further detail.

4.2.1 A balanced process for Frequency performance payments

The draft rule sets out a process for frequency performance payments where positive contributions would be scaled, or normalised, by the aggregate of all negative contributions. This approach is designed to build on the existing causer pays framework to value positive contributions as an extension of the valuation implied through the allocation of regulation costs to negative contribution factors.

However, in response to stakeholder feedback on the draft rule, and guided by the analysis and investigation provided by IES, the revised rule sets out a balanced and independent process to measure and value active power behaviour that impacts power system frequency. Under the revised rule, the measurement of contributions for positive and negative performance will balance and be valued independently of the process for the allocation of costs for regulation services. The balancing of positive and negative contribution factors is reflected in the principles set out in Cl 3.15.6AA(f) of the revised rule, which would guide AEMO's determination of the frequency contribution factors procedure. These include that:

(7) a contribution factor is a number between -1 and 1.

In the revised rule, the contribution factor term in the transactions for the frequency performance payments is not divided by the aggregate of all negative contributions. Instead, AEMO will be required to set out the process under the frequency contribution factors procedure, for determining contribution factors in accordance with the principles set out in Cl 3.15.6AA(f). The requirement for the contribution factors to be between -1 and 1 provides for contribution factors are normalised and balanced.

The normalised contribution factors reflect the relative deviations of eligible units relative to the aggregate (positive or negative) deviations of all units. The IES analysis showed that a top down energy balance approach could be used to account for the impact of the power system plant that do not have appropriate metering, referred to as 'the residual'. This energy balance approach is used to derive a contribution factor for the residual component and leads to a result where the positive contributions are balanced by equal and opposite negative contributions.

Stakeholder responses to the draft determination expressed a general concern that the frequency performance payments process set out in the draft rule would not effectively value PFR. Stakeholders were concerned that the process in the draft rule would deliver insufficient financial incentives to encourage the provision of PFR over operational timescales and the investment in frequency responsive capability to provide this service over the long term.

The separation of the valuation of frequency performance payments from the process for regulation FCAS cost recovery under the revised rule allows for a greater range of financial outcomes under the frequency performance payments process, than was envisaged under the draft rule. This is demonstrated through the settlement results produced through the IES analysis and summarised in section 4.2.4. Subject to the input assumptions in relation to the weighting and scaling of the frequency performance payments, the IES settlement results show that the gross frequency performance payments can be of a similar size to payments for regulation FCAS enablement. The consideration of financial weight and scaling is discussed in the following sections.

4.2.2 Weighting by the price for regulation services

In the draft rule, the total cost of raise or lower regulation services (TSFCAS) was used as the financial weighting for frequency performance payments. The revised rule maintains the link to the cost of regulation services, but instead uses the regulation price (raise or lower) in $/MW per hour as the financial weighting. The regulation price is divided by 12 to give a price in $/MW per five minute trading interval. This reflects the fact that there are 12 trading intervals in each hour.

The Commission considers that the regulation price is the nearest price signal in the market for the value of PFR.

In principle, the regulation price is reflective of the costs of providing regulation services, including:

- the opportunity cost of withholding capacity for raise services, i.e. the value of energy withheld as headroom that could have been sold on the spot market
- the opportunity cost of unearned energy revenue when delivering lower services
- the utilisation cost of generating additional energy when providing raise services
- the inefficiency cost of providing headroom or footroom by generating at a less efficient operating point, e.g. from an increase in heat rate
- the operations and maintenance cost from increased mileage / wear and tear as a result of providing regulation services

Apart from the costs associated with reserving headroom or footroom, the costs of providing PFR are broadly the same as those for providing regulation services. In their submission to the draft determination, Iberdrola expressed support for the weighting of frequency performance payments by Regulation FCAS prices, noting that this approach was "more likely to reflect the value (opportunity cost) of reserving headroom from the energy market than the energy price itself".[35]

The Commission investigated two alternative financial weightings for frequency performance payments, (i) the energy spot price, and (ii) an implied price based on the regulation FCAS supply curve.

The energy spot price was proposed as an alternative financial weighting given its appeal as an intuitive opportunity cost for providing frequency control services, e.g. being made whole for energy not generated when providing lower services. However, a minimum financial weighting of $0/MW would likely need to be imposed in order to prevent disincentives arising from negative spot prices. Moreover, the spot price would already be considered in the

35 Iberdrola, Submission to the draft determination, pp.10-11.

economically efficient short-run offer pricing for regulation services, suggesting the regulation price as a more appropriate financial weighting.[36]

Another alternative financial weighting examined was an implied price based on the regulation FCAS supply curve. In this approach, the price for frequency performance payments (in $/MW) is determined by clearing the regulation FCAS supply curve with the aggregate requirement for corrective response (as opposed to the regulation enablement amount). This price would effectively serve as an estimate for the price of PFR, were it procured via a market mechanism.

However, a few issues have been identified with the use of the regulation FCAS supply curve in determining a frequency performance payment price. Firstly, the regulation FCAS market is relatively shallow and the supply curve is based on offers from a subset of facilities that have been accredited for providing regulation services. The number of facilities potentially providing PFR is much larger and includes many facilities that do not participate in regulation FCAS. Therefore, the private information (e.g. cost drivers) of these facilities would not be appropriately reflected in the regulation FCAS supply curve. Secondly, the FCAS supply curve is potentially open to gaming, particularly from offers that would otherwise have been out-of-merit in the regulation FCAS market (but could still influence the frequency performance payment price). The fact that there is no physical requirement to honour offers in this part of the supply curve means that there are no consequences for bad faith offers. Given these issues, along with a more complicated practical implementation, the Commission views the regulation price as the more preferred financial weighting.

4.2.3 Scaling by the requirement for corrective response

Under the revised rule the scaling of the frequency performance payments has been simplified to a single term - RCR or the requirement for corrective response, which is a value in MW. AEMO must describe in the frequency contribution factor procedure, the method it will use to determine RCR. RCR is a measure of the total volume in MW across the power system that contributed to reducing the aggregate deviation in frequency of the power system during a trading interval.

Under the draft rule, the frequency performance payments would have been scaled by the requirement for the regulation service during the trading interval as a proportion of the regulation amount enabled at the start of the trading interval. This became the term RR/EA in the draft rule.

Stakeholder feedback to the draft rule raised concerns in relation to the definition of the term 'RR' or regulation requirement. Stakeholders recognised that this parameter played an influential role in the scale of frequency performance payments delivered through the proposed arrangements, but they considered that this term was not adequately defined in the draft rule or draft determination. Stakeholders requested that the Commission define this

36 For example, refer to J. Gilmore, T. Nolan, and P. Simshauser, "The Levelised Cost of Frequency Control Ancillary Services in Australia's National Electricity Market", EPRG Working Paper 2202, January 2022, https://www.eprg.group.cam.ac.uk/wp-content/uploads/2022/01/2202-Text1.pdf

term more clearly, to support robust and transparent outcomes through the frequency performance payments process.[37]

Similarly, AEMO noted that the regulation requirement term set out in the draft rule could be interpreted to be the requirement for enablement of regulations services, which is a value that does not vary significantly from one trading interval to the next. AEMO suggested that this term could be more clearly defined to support a frequency performance payments process that would dynamically adjust to the changing needs in the power system, as envisaged in its discussion paper, *Primary frequency response incentive arrangements*.[38]

AEMO supported the inclusion of a scaling component that would recognise that the requirement for corrective response could exceed the enablement amount for regulation services.[39]

> The primary response will respond in proportion to the change in frequency and although secondary control will eventually need to correct any persisting error, primary response could exceed the EA. The purpose of the scaling factor is to allow performance payments to exceed the cost of Regulation FCAS and was thought consistent with introducing payments for mandatory primary response, which could exceed EA.

The scaling of plant performance is a key component in the valuation of helpful and harmful active power deviations. As explained in section 4.2.2, the Commission considers that the prices determined through market dispatch for the regulating raise and regulating lower service present a fair valuation of the ability to provide active power frequency response within a dispatch interval. However, this price in $/MW for each trading interval requires a MW volume in order to result in a meaningful trading amount. For the dispatch of regulation services, the volume is the global enablement amount, which combines with the price to yield a system wide cost (TSFCAS) or is combined with an individual enablement volume to yield a unit trading amount.

The 'RCR' term as it is used in the revised frequency performance payments transaction plays a similar role as the enablement amount for the settlement of payments in relation to provision of regulation services. That is, it defines the volume of the service required in MW and therefore, when combined with a price in $/MW, creates a total sum for the cost of that service for the relevant trading interval. The concept of RCR as described in paragraph (g)(6) of the revised rule is envisaged to include and account for the total of all helpful active power deviations across the power system. This recognises that there may be a significant quantity of active power deviations for metered plant that are balancing out harmful deviations without translating into a significant frequency error or a significant requirement for regulation services.

37 For example, Submission to the draft rule determination: Iberdrola, p.12.

38 AEMO, Submission to the draft determination, pp.5-6.

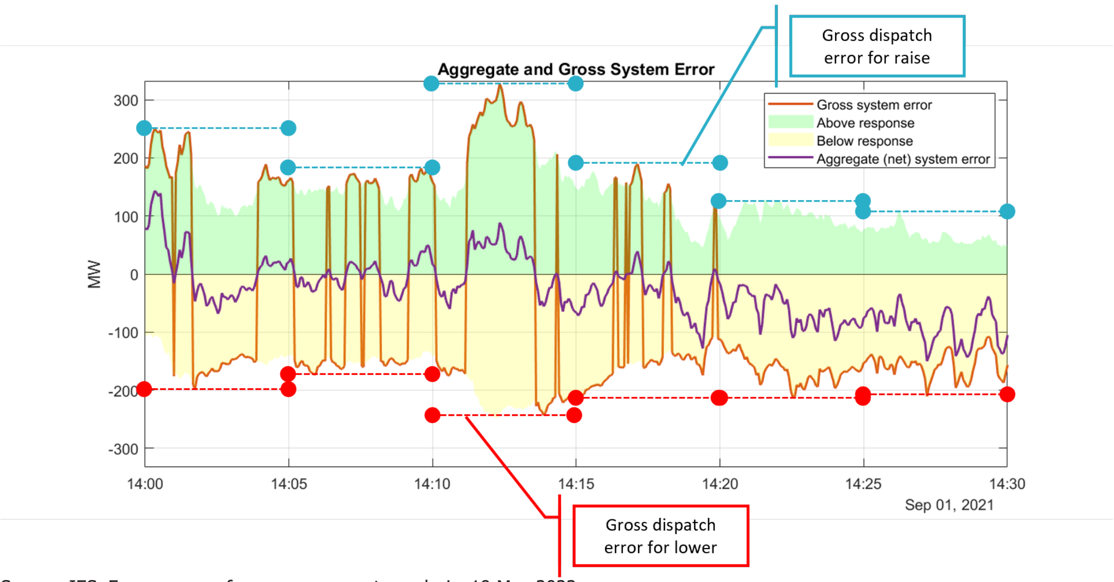
39 AEMO, Submission to the draft determination, p.5.

The IES analysis investigated this concept in some depth, with the goal of accounting for and valuing the total sum of helpful active power deviations through the frequency performance payments.[40] . The process developed with IES aggregated all deviations for metered plant(typically generation) and then presented these deviations as either above target or below target deviations. The above target deviations contributed to raising the frequency of the power system while the below target deviations contributed to reducing the frequency of the power system. An example of this provided in Figure 4.7 based on IES analysis of historical causer pays data.

The sum of above target and below target deviations yields a remainder that is referred to as 'aggregate(net) dispatch error'. This is the net deviation of plant with appropriate metering. Based on the energy balance in the power system, the net deviation of metered plant is understood to be equal and opposite to the aggregate deviation of the non-metered or residual component.

The aggregate(net) dispatch error correlates closely with the range of metrics for system frequency as shown in Figure 4.1. However it is clear that the gross dispatch error, shown in red, is always significantly larger than the aggregate (net) dispatch error, shown in purple.

Figure 4.7: Aggregate (net) and gross dispatch error



Source: IES, Frequency performance payments analysis, 19 May 2022.
Note: Above response is the sum of all positive deviations for plant with appropriated(SCADA) metering.
Note: Below response is the sum of all negative deviations for plant with appropriated(SCADA) metering.
Note: Aggregate(net) dispatch error is the net sum of above and below response
Note: Gross dispatch error tracks the maximum of the above and below response and is a measure of the total or gross positive deviations

Following consideration of a number of alternative scaling methods, the IES analysis landed on the use of gross dispatch error as its preferred measure of the requirement for corrective

40 This includes active power deviations as a result of PFR and regulation response.

response in the frequency performance payments transactions. The benefits of this value include:

- it is a readily quantifiable value that is based on the measurement of all active power deviations for plant with appropriate metering
- it is independent of AGC and the requirement or use of regulation services
- by accounting for all deviations, it would (subject to the effectiveness of the performance metric) include primary and secondary response.

The main drawback of the gross deviation value, is that it can only be known following the end of the trading interval, based on the compilation of all data for plant with appropriate metering, as such it cannot be known in advance or in real time. This characteristic was discussed with the technical working group, with the group consensus being that the benefit of gross dispatch error in accounting for all measured deviations outweighed the fact that this introduced an ex-post element to the transactions.

Gross dispatch error is a value that was developed through the IES analysis as an effective measure of the requirement for corrective response in the power system. Whilst it may also include offsetting errors within the metered population of eligible units as well as primary and secondary response, the IES analysis showed that it is difficult to differentiate between the two, because they may both align with the performance metric (of combined Hz). As a result, IES concluded that it is appropriate to measure and pay for gross error relative to dispatch through the scaling component.

The revised rule provides AEMO with some flexibility as to how it defines the requirement for corrective response in its procedure, while at the same time providing guidance as to what is envisaged by this term. Finally, as discussed in section 4.1.5, the data associated with the determination of RCR, would be published by AEMO in accordance with the timetable for publication of market information.

4.2.4 Estimated financial impacts from the revised process

The IES analysis produced settlement results that provide an indication of the scale of financial outcomes that would be expected following the implementation of a frequency performance payments process based on the framework set out in the revised rule.

The high level findings from the IES analysis are:

- That the scale of gross frequency performance payments (and cost allocations) would be expected to be similar in size to the total costs for regulation services.
- That the net payments, taking into account payments and cost allocations that cancel out over the relevant period, would be expected to be in the order of one third of the costs of regulation services.

These results provide a valuable indication of the scale of frequency performance payments relative to the costs of regulation services. As a point of reference, historical regulation costs in the NEM range from $4.6 million in 2013 to $126.8 million in 2019, with an average over recent years (2019 to 2021) of $93 million.[41] Based on the historical cost for regulation services being an accurate representation of future costs and ignoring dynamic economic effects, the scale of gross frequency performance payments would be expected to be in the order of $90 million per year, while the net payments would be expected to be in the order of $30 million per year.

The Commission notes that the IES analysis is a static analysis based on historical data, it does not account for dynamic economic effects and is not likely to provide an accurate indication of the actual size of frequency performance payments following implementation of the process set out in the revised rule. The Commission expects that the implementation of frequency performance payments would put downward pressure of regulation prices, based on dynamic market effects.

For example, the IES analysis shows that, where the reference trajectory is based on target to target only, and does not include the regulation component, plant enabled to provide regulation services will receive a substantial portion of the frequency performance payments. The additional revenue provided to regulation providers would be expected to support competitive behaviour that would place downward pressure on the market prices for regulation services. Following the implementation of the frequency performance payments arrangements, the price for regulation services would be expected to drop until a new dynamic equilibrium is found, where the combined revenue from frequency performance payments and regulation enablement balances out against the costs of providing PFR and the regulation service(s).

The high level results from the IES short period analysis are shown in Figure 4.8.

The high level results from the IES long period analysis are shown in Figure 4.9.

These results are based on the following calculation scenarios:[42]

- Scenario 3.8 — normalised factors — Gross dispatch error scaling
  - Performance metric: Combined Hertz
  - Reference trajectory: Target to target
  - Contribution factor normalisation: yes — unit deviations divided by aggregate deviations
  - Scaling: by Gross dispatch error
- Scenario 3.14 — Raw factors — Hz spread scaling
  - Combined Hertz performance metric
  - Target to target reference trajectory
  - Contribution factor normalisation: No — Contribution factors maintained in the raw form, unit deviations multiplied by frequency deviations to produce deviation factor in units of MWHz.

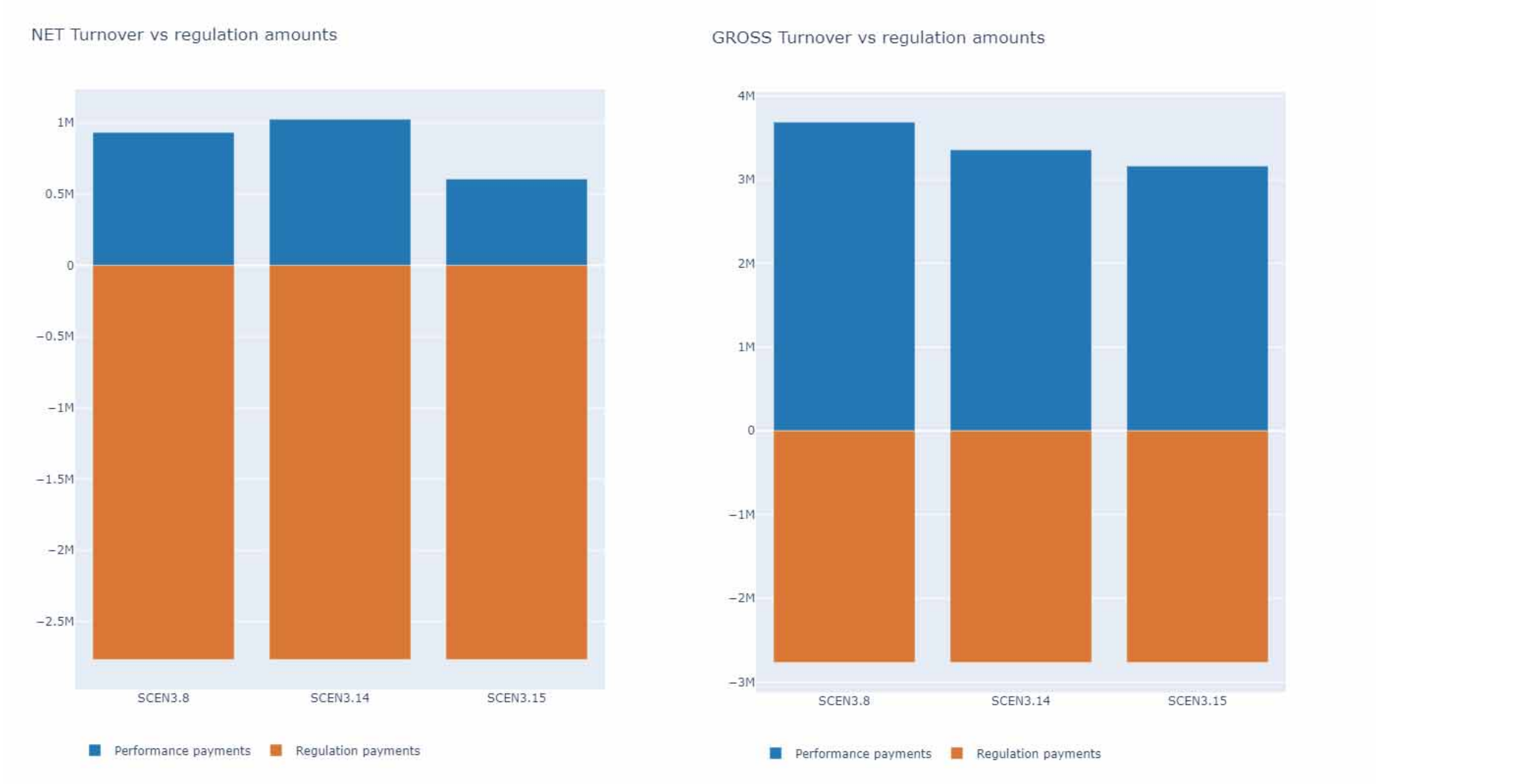
41 See analysis of historical regulation costs included in appendix C .

42 Refer to chapter 4 of the IES report for further detail on these scenarios. IES, Frequency performance payments analysis, 19 May 2022.

    - Scaling by frequency reference at which the deviations are priced — in this case, the inverse of the mandatory PFR deadband of 0.015Hz was used = 1/0.015.
- Scenario 3.15 — Normalised factors — Gross dispatch error scaling — Inclusion of regulation component
    - Performance metric: Combined Hertz
    - Reference trajectory: Target to target plus regulation component
    - Contribution factor normalisation: yes — unit deviations divided by aggregate deviations
    - Scaling: by Gross dispatch error

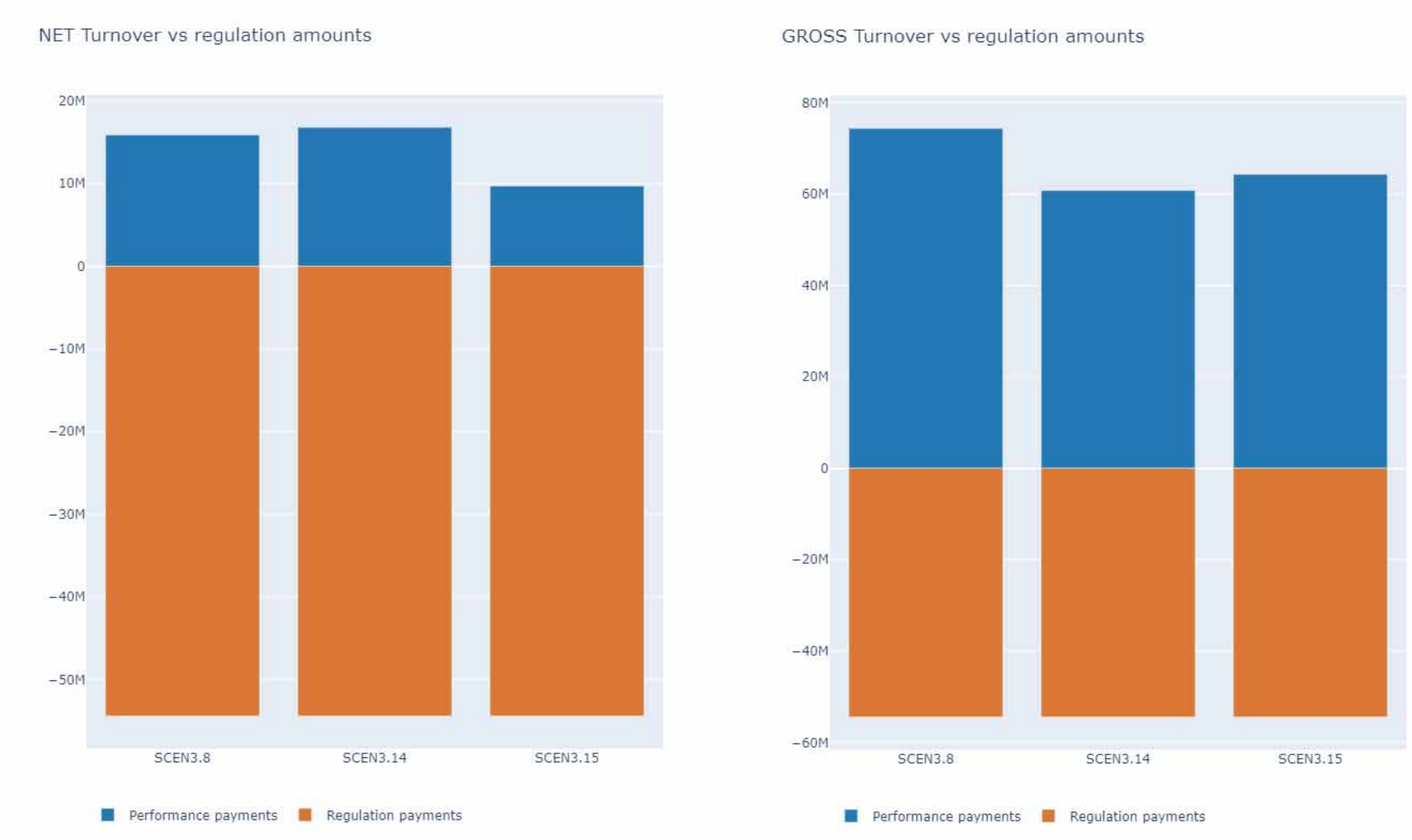
For these results, net turnover represents the expected revenues for each eligible unit after the netting out of positive and negative payments over the relevant time period, in this case two weeks. Gross turnover reflects the total positive frequency performance payment for each eligible unit over the relevant period, it does not account for negative frequency performance payments that may occur over the same period.

Figure 4.8: Turnover vs regulation costs for short period analysis



Source: IES, Frequency performance payments analysis, 19 May 2022.
Note: Based on IES analysis of causer pays data for the two weeks commencing on 1 September 2021

Figure 4.9: **Turnover vs regulation costs for long period analysis**



Source: IES, Frequency performance payments analysis, 19 May 2022.
Note: Based on IES analysis of causer pays data for the two weeks commencing on 1 September 2021

4.3 Allocation of costs for enablement of regulation services

As in the draft rule, the revised rule maintains the separation of the allocation of costs for regulation services used and not-used during the trading interval. However, the revised rule takes a different approach to how the allocation of costs for regulation services is determined.

As for the draft rule, the costs for regulation services used would be allocated based on negative contribution factors determined for the trading interval.

However, in response to stakeholder feedback on the draft rule, the revised rule takes a different approach for the allocation of costs for regulations services not used. Under the revised rule, these costs would be allocated based on negative default contribution factors, rather than being based on energy consumed or generated in the trading interval, as in the draft rule. As described in section 4.1.1, these default contribution factors would be determined in advanced by AEMO. The Commission's expectation is that this would be based on the average performance of eligible units over a longer period. The default contribution factors would apply for a billing period, which is the 7-day period from Sunday 12:00am to the following Sunday 12:00am.

The approach to the allocation of costs for regulation services not-used recognises that it is not possible to identify specific plant behaviour during a trading interval as causing the need for regulation services that were not used during that trading interval. At the same time, it is appropriate for the long-term behaviour of eligible plant to be used as the basis for the allocation of these costs, similar to the current causer pays process. This approach aligns with the views of a number of stakeholders expressed in submissions to the draft determination.[43] It also provides an incentive to encourage consistently helpful frequency response from eligible plant, which will complement the sharp incentives provided through the frequency performance payments and the allocation of costs for regulation service used in each trading interval.

Further commentary on the investigation of alternative approaches for the allocation of costs for enablement of regulation services is provided in section 3.10 of the IES report, *Frequency performance payments analysis*.[44]

The Commission notes the consideration by IES for regulation costs to be entirely allocated to participants that do not have appropriate (SCADA) metering, i.e. the residual component. The basis for this proposal is a concern that participants with appropriate metering may act preemptively in the face of high regulation prices, by withdrawing capacity from the energy market. The allocation of regulation costs to participants in the residual component, who do not have appropriate metering, is expected to mitigate this risk.

43 For example, Submission to the draft rule determination: Iberdrola, pp.13-14.

44 Available on the project page https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

The Commission does not consider that it is appropriate to allocate the entirety of regulation costs to participants in the residual - non-metered component. This view is based on the following reasoning:

- Participants in the residual component are passive and not able to manage the financial risk associated with the allocation of the entirety of regulation costs.
- The residual component is expected to shrink into the future due to increasing demand-side participation, as envisaged through the ESB post 2025 market design.[45]

Under the revised rule, participants in the residual component would be allocated costs for regulation services in proportion to the estimated impact of the associated plant on the need to raise or lower the frequency of the power system. The impact of plant that do not have appropriate metering would be reflected in the residual contribution factor described in Cl3.15.6AA(f)(3) of the revised rule.

A summary of the approach to the allocation of regulation costs under the revised rule is included in Table 4.3.

45 Energy Security Board, Post-2025 Market Design - Final advice to Energy Ministers - Part B, 27 July 2021, pp.87 - 89.

Table 4.3: Allocation of costs for enablement of regulation services

ELEMENT	DRAFT RULE	REVISED RULE	REASONING
Allocation of costs for regulation services - used	Costs of services used allocated based on negative participant contribution factors determined over the trading interval.	**As per the draft rule**	The negative contribution factors determined for a trading interval represent a good measure of those who caused the need for regulation services. This is a real time application of the current causer pays process and is generally accepted by stakeholder submissions to the draft determination.
Allocation of costs for regulation services - not used	Costs of services not used allocated based on energy consumed or generated during the trading interval.	**Change to the draft rule** Costs of services not used allocated based on negative default contribution factors.	Stakeholder responses to the draft determination were broadly unsupportive of the proposal to allocate a portion of regulation costs based on energy consumed or generated during the trading interval. The allocation of costs for services not used based on default contribution factors is an alternative approach that reflects the long-term behaviour of power system plant.

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
DRSP	Demand response service provider
DSCP	Double-sided causer-pays
EA	Enablement amount
EMMS	Energy market management system
ESB	Energy Security Board
ESS	Essential system services
FFR	Fast frequency response
FI	Frequency indicator
FOS	Frequency operating standard
FPP	Frequency performance payment
IBFFR	Inverter based fast frequency response
ISP	Integrated System Plan
MASS	Market ancillary service specification
MCE	Ministerial Council on Energy
MNSP	Market network service provider
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
RCR	Requirement for corrective response
Rocof	rate of change of frequency
RR	Regulation requirement
TNSP	Transmission network service provider
VPP	virtual power plant
VRE	variable renewable energy (generation)

A FREQUENCY CONTROL EXPLAINED

A.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.[46]

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.[47] Continuous primary frequency control helps to control system frequency during normal operation by responding to small frequency variations. Primary frequency control also helps to stabilise the system following larger disturbance events, this is referred to as Contingency response.

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.

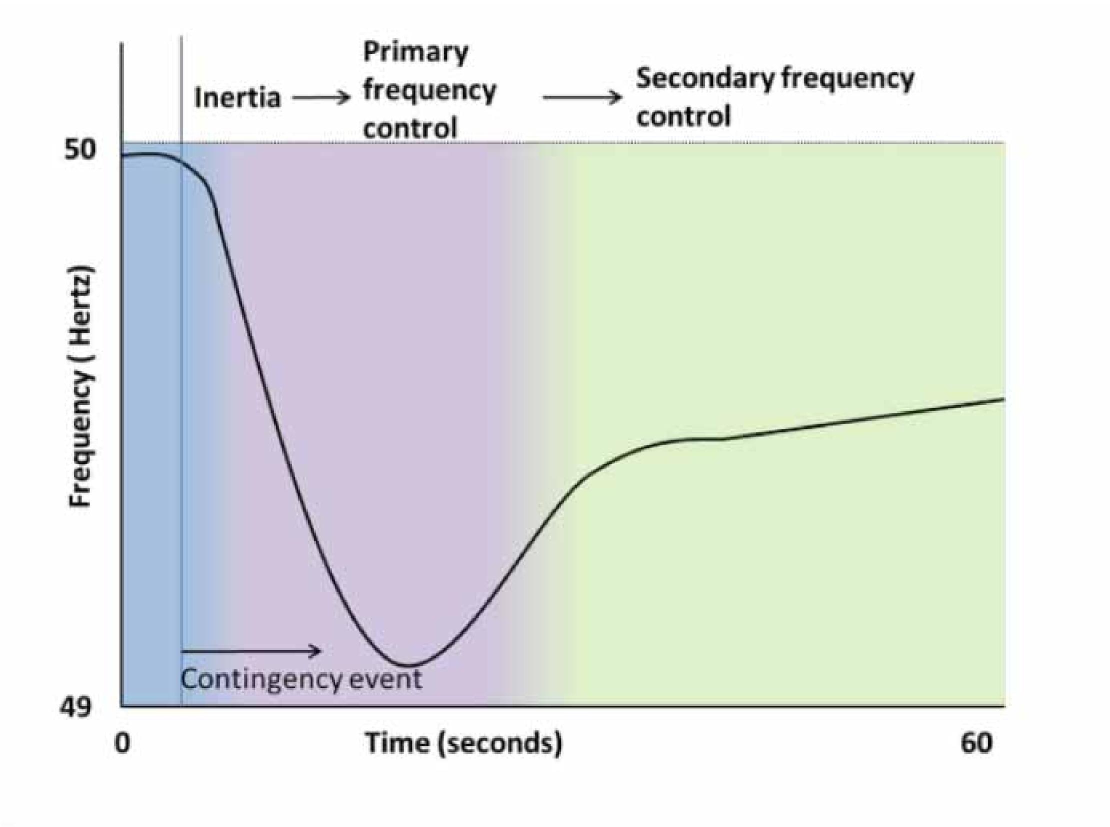
46 See AEMO's Energy Explained: Frequency Control, 24 June 2020. https://aemo.com.au/en/newsroom/energy-live/energy-explained-frequency-control

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

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 A.1.

Figure A.1: **Coordinated frequency control following a contingency event**



Source: AEMC

The existing arrangements that support frequency control in the NEM are described below in appendix A.2.

A.2 The NEM 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.[48]

AEMO is required under the National Electricity Rules (NER) to operate and maintain the power system in a "secure operating state".[49] 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:[50]

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.[51]

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).[52] 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.
- **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.
- **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.

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

49 NER clause 4.2.6(a)

50 NER cl 4.2.4(a)

51 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.

52 NER clause 4.4.1(a)

- **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.

B BACKGROUND ON THE CONSULTATION PROCESS FOR THIS RULE CHANGE REQUEST

This appendix provides an overview of the consultation process for the *Primary frequency response incentive arrangements* rule change.[53]

Consultation papers

On 19 September 2019, the Commission published a consultation paper to commence the rule making process and consultation in respect of this rule change request, *Primary frequency response incentive arrangements*.[54] The Commission received 33 submissions in response to this consultation paper. On 2 July 2020, the Commission published another consultation paper seeking further stakeholder input on this rule change request and how it should be assessed in the context of six other rule change requests that relate to the provision of system security services in the NEM.[55] The Commission received 43 submissions as part of this consultation.

First Directions paper

On 17 December 2020, the Commission published a directions paper for both rule change requests that relate to the arrangements for frequency control in the NEM, *Fast frequency response market ancillary service* and *Primary frequency response incentive arrangements*.[56] The directions paper set out the Commission's initial views and high-level policy directions on key issues in relation to the arrangements for fast frequency response and primary frequency response in the NEM. The Commission received 29 submissions which have informed the development of this draft rule determination. In making this draft determination and draft rule, the Commission has considered all issues raised by stakeholders in submissions in relation to AEMO's rule change request. Issues raised in submissions were discussed and responded to throughout the draft rule determination.

Draft determination

On 16 September 2021, the Commission published a draft determination and a draft rule for the PFR Incentive arrangements rule change. The draft rule confirms the existing Mandatory PFR arrangements as enduring and introduce a double-sided frequency performance payment and allocation arrangement to incentivise plant behaviour that helps to control power system frequency, lowering the costs of frequency control for consumers. It also includes additional reporting arrangements for AEMO and the AER in relation to frequency performance and the costs of frequency control services.

53 *The documents and submissions referenced below are available on the project web page: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements*

54 This notice was published under s.95 of the National Electricity Law (NEL).

55 AEMC, *System services rule changes - consultation paper*, 2 July 2020. Available at: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

56 AEMC, Frequency control rule changes — Directions paper, 17 December 2020. Available at: https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements

The Commission received 22 submissions in response to the draft determination. An overview of the issues raised by stakeholders is provided in section 3.2. This directions paper responds to issues raised by stakeholders in relation to the frequency performance payments process set out in the draft rule.

Technical working group

The Commission has continued to engage with experts from industry, and consumer groups through the frequency control technical working group(TWG), which was formed in October 2019 to discuss issues related to the frequency response rule change requests.

Further TWG meetings were convened on 8 October 2020, 4 March 2021, and 21 May 2021 to discuss the frequency control rule change requests including the PFR incentive arrangements and the FFR market ancillary services rule changes.

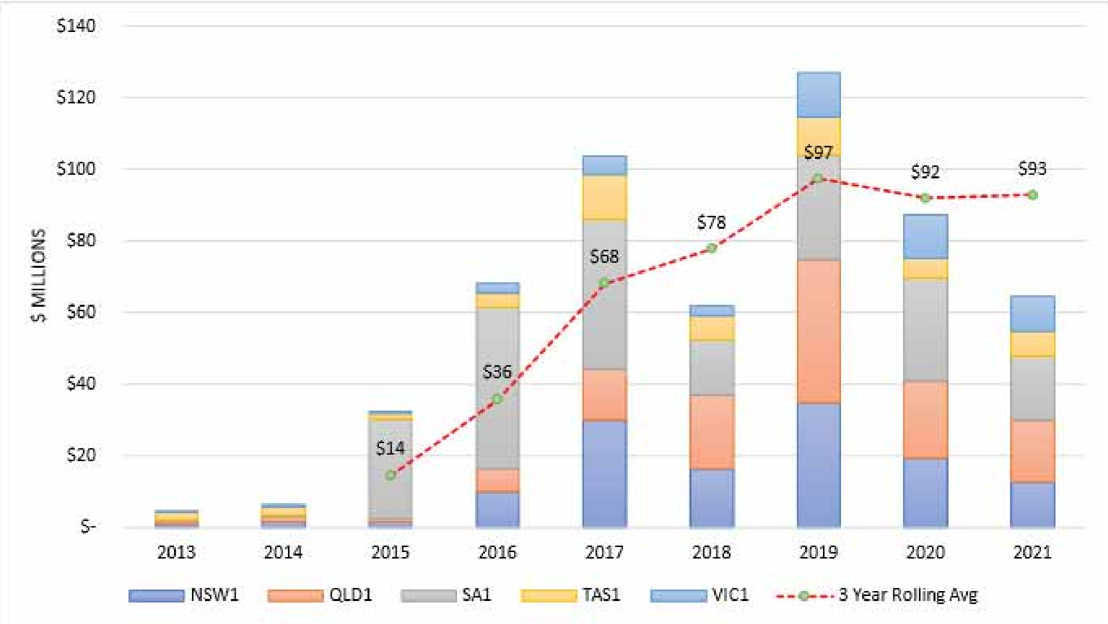
TWG meetings dedicated to the *Primary frequency response incentive arrangements* rule change request were held on 23 and 29 July 2021 prior to the publication of the draft determination. Following the publication of the draft determination, TWG meetings were held on 15 October 2021, 17 December 2021, 3 March 2022 and 8 April 2022.

C HISTORICAL REGULATION COSTS IN THE NEM

To provide an indication of the estimated financial impact of the proposed frequency performance payments, it is helpful to look at historical regulation costs. The following graphs show the combined cost of the regulating raise services and regulating lower services since 2013. The dotted red line indicates the three-year moving average of these costs.

This analysis shows that regulation costs in the NEM since 2013 have ranged from $4.6 million in 2013 to $126.8 million in 2019, with an average over recent years (2019 to 2021) of $93 million.

Figure C.1: Historical costs for regulation services



Source: AEMC analysis of historical NEM market data - available at https://aemo.com.au/energy-systems/electricity/national-electricitymarket-nem/data-nem/market-management-system-mms-data/dispatch

D REVISED RULE DRAFTING

Appendix D

Indicative changes to the National Electricity Rules

Note:

This document shows indicative changes to the relevant parts of the National Electricity Rules (NER) proposed to be made by the *National Electricity Amendment (Primary frequency response incentive arrangements) Rule 2022*. The changes are shown in a modified version of the NER that incorporates, where relevant, final rules made by 19 May 2022 which take effect as of October 2024. This modified version of parts of the NER is provided for information only and should not be used for any other purpose. The Australian Energy Market Commission does not guarantee the accuracy, reliability or completeness of this version of the NER or the mark-up.

This document includes changes to the NER to be made by the following rules:

+ National Electricity Amendment (Mandatory primary frequency response) Rule 2020 (Sch 2 commences 4 June 2023)
+ National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021 (commences 3 June 2024)

CHAPTER 3

3.11.2A AER reporting on market ancillary services markets

(a) For the purposes of section 18C(2)(c) of the *NEL*, the *AER* must prepare and *publish* a report in respect of *market ancillary services* for each calendar quarter.

(b) The report prepared under paragraph (a) must be *published* within 30 *business days* of the end of each calendar quarter and must contain:

(1) the following information in relation to each *market ancillary service* listed in clause 3.11.2(a) for the quarter:

(i) the total costs paid to *Ancillary Service Providers* for the provision of the *market ancillary service* for each *region*;

(ii) the total quantity of the *market ancillary service* that was *dispatched* by *AEMO* in each *region*;

(iii) the lowest, highest and average *ancillary service price* for each *region* for the *market ancillary service*; ~~and~~

(iv) the number and types of *Ancillary Service Providers*; and

(v) the total costs of *frequency performance payments* for each *region*.

(2) the *AER*'s analysis of key trends and outcomes in the *markets* for *market ancillary services* during the quarter; and

(3) any other relevant information the *AER* considers necessary or convenient to include in the report.

***

3.15.6A Ancillary service transactions

Definitions

(a0) In this clause 3.15.6A:

regional benefit ancillary services procedures means the procedures to determine the relative benefit that each *region* is estimated to receive from the provision of *NMAS.*

regional benefit factors means the factors to allocate, between *regions*, the costs associated with the provision of *NMAS* under each *ancillary services agreement* in accordance with the regional benefit ancillary services procedures.

~~**Scheduled Participant** has the meaning given to it by subparagraph (k)(5).~~

***

(h) The total amount calculated by *AEMO* under paragraph (a) for the *regulating raise service* or the *regulating lower service* in respect of each *trading interval* must be allocated by *AEMO* to each *region* in accordance with the following procedure and the information provided under clause 3.9.2A(b):

(1) allocate on a pro-rata basis for each *region* and for the relevant *trading interval* the proportion of the total amount calculated by *AEMO* under

paragraph (a) for the *regulating raise service* and *regulating lower service* between *global market ancillary service requirements* and *local market ancillary service requirements* to the respective marginal prices for each such service; and

(2) calculate for the relevant *trading interval* the sum of the costs of ~~acquiring~~ the *regulating raise service* or the *regulating lower service* for each *global market ancillary service requirement*~~s~~ for all *regions*, and ~~the sum of the costs of acquiring~~for each *local market ancillary service requirement*~~s~~ for all relevant *regions*, as determined under subparagraph (1); and

(3) allocate for each *trading interval* the costs of the *global market ancillary service requirements* and *local market ancillary service requirements* calculated in subparagraph (2) in accordance with clauses 3.15.6AA(c) and (d).

(i) When *AEMO* dispatches a quantity of *regulating raise service* or *regulating lower service* in addition to the quantity it determines in accordance with the *dispatch algorithm*, *AEMO* must:

(1) for the purposes of paragraphs (f) and (g), include the additional quantity in the cost of *delayed services*; and

(2) for the purposes of paragraphs (h) and clauses 3.15.6AA(c) and (d), exclude the additional quantity from the cost of *regulation services*,

taking into account the requirements in clauses 3.8.1(a) and (b) to maximise the value of *spot market* trading.

~~(i) In each *trading interval* in relation to:~~

~~(1) each *Cost Recovery Market Participant* which has metering to allow their individual contribution to the aggregate deviation in *frequency* of the *power system* to be assessed, an *ancillary services transaction* occurs, which results in a *trading amount* for that *Cost Recovery Market Participant* determined in accordance with the following formula:~~

$$\cancel{TA = PTA \times -1}$$

~~and~~

$$\cancel{PTA = \text{the aggregate of} \left(TSFCAS \times \frac{MPF}{AMPF} \right)}$$

~~for each *trading interval* for *global market ancillary service requirements* and *local market ancillary service requirements* where:~~

~~TA (in $)~~	=	~~the *trading amount* payable by the *Cost Recovery Market Participant* in respect of the relevant *region* and *trading interval*;~~
~~TSFCAS (in $)~~	=	~~the total of all amounts calculated by *AEMO* under paragraph (h)(2) for the~~

		~~*regulating raise service* or the *regulating lower service* in respect of a *trading interval*;~~
~~MPF (a number)~~	~~=~~	~~the contribution factor last set by *AEMO* for the *Cost Recovery Market Participant*, as the case may be, under paragraph (j) for the *region* or *regions* relevant to the *regulating raise service* or *regulating lower service*; and~~
~~AMPF (a number)~~	~~=~~	~~the aggregate of the MPF figures for all *Cost Recovery Market Participants* for the *trading interval* for the *region* or *regions* relevant to the *regulating raise service* or *regulating lower service*.~~

~~or~~

~~(2) each *Cost Recovery Market Participant* for whom the *trading amount* is not calculated in accordance with the formula in subparagraph (1), an *ancillary services transaction* occurs, which results in a *trading amount* for that *Cost Recovery Market Participant* determined in accordance with the following formula:~~

$\cancel{TA = PTA \times -1}$

~~and~~

$$\cancel{PTA = \text{the aggregate of} \left(TSFCAS \times \frac{MPF}{AMPF} \times \frac{TCE}{ATCE} \right)}$$

~~for each *trading interval* for *global market ancillary service requirements* and *local market ancillary service requirements* where:~~

~~TA (in \$)~~	~~=~~	~~the *trading amount* payable by the *Cost Recovery Market Participant* in respect of the relevant *region* and *trading interval*;~~
~~TSFCAS (in \$)~~	~~=~~	~~has the meaning given in subparagraph (1);~~
~~MPF (a number)~~	~~=~~	~~the aggregate of the contribution factor set by *AEMO* under paragraph (j) for *Cost Recovery Market Participants*, for whom the *trading amount* is not calculated in accordance with the formula in subparagraph (1) for the *region* or *regions* relevant to the~~

		~~*regulating raise service* or the *regulating lower service*;~~
~~AMPF (a number)~~	=	~~the aggregate of the MPF figures for all *Cost Recovery Market Participants* for the *trading interval* for the *region* or *regions* relevant to the *regulating raise service* or *regulating lower service*;~~
~~TCE (in MWh)~~	=	~~the *adjusted consumed energy* amounts for the *Cost Recovery Market Participant* for the *trading interval* in the *region* or *regions* relevant to the *regulating raise service* or *regulating lower service*; and~~
~~ATCE (in MWh)~~	=	~~the aggregate of the *adjusted consumed energy* amounts for all *Cost Recovery Market Participants*, for whom the *trading amount* is not calculated in accordance with the formula in subparagraph (1), for the *trading interval* for the *region* or *regions* relevant to that *regulating raise service* or *regulating lower service*.~~

~~(j) *AEMO* must determine for the purpose of paragraph (i):~~

~~(1) a contribution factor for each *Cost Recovery Market Participant*; and~~

~~(2) notwithstanding the estimate provided in paragraph (nb), if a *region* has or *regions* have operated asynchronously during the relevant *trading interval*, the contribution factors relevant to the allocation of *regulating raise service* or *regulating lower service* to that *region* or *regions*,~~

~~in accordance with the procedure prepared under paragraph (k).~~

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

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

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

~~(3) for the purpose of paragraph (j)(2), the contribution factor determined for a group of *regions* for all *Cost Recovery Market Participants* that do not have metering to allow the individual contribution of that *Cost Recovery Market Participants* to the aggregate need for *regulation services* to be assessed, must be divided between *regions* in proportion~~

~~to the aggregate of the *adjusted consumed energy* amounts for the *regions*;~~

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

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

~~(i) subject to the provision of *primary frequency response* by that Scheduled Participant in accordance with the *Primary Frequency Response Requirements*, the Scheduled Participant achieves its *dispatch* target at a uniform rate;~~

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

~~(iii) the Scheduled Participant is not *enabled* to provide a *market ancillary service*, but responds to a need for *regulation services* in a way which tends to reduce the aggregate deviation;~~

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

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

~~(i) subject to the provision of *primary frequency response* by that *semi-scheduled generating unit* in accordance with the *Primary Frequency Response Requirements*, achieves its *dispatch level* at a uniform rate;~~

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

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

~~(l) *AEMO* may amend the procedure referred to in clause 3.15.6A(j) from time to time.~~

~~(m) *AEMO* must comply with the *Rules consultation procedures* when making or amending the procedure referred to in clause 3.15.6A(k).~~

~~(n) *AEMO* must *publish*, in accordance with the *timetable*, the historical data used in determining a factor for each *Market Participant* for the purposes of clauses 3.15.6A(h) and (i) in accordance with the procedure contemplated by clause 3.15.6A(k).~~

~~(na) Notwithstanding any other provisions of the *Rules*, *AEMO* must *publish* the factors determined in accordance with clause 3.15.6A(j)(1) at least 10 *business days* prior to the application of those factors in accordance with clauses 3.15.6A(h) and 3.15.6A(i).~~

~~(nb) When a *region* is or *regions* are operating asynchronously, *AEMO* must *publish* (where appropriate in accordance with the procedure developed under paragraph (k)), an estimate of the contribution factors referred to in paragraph (j)(2) to be applied for information purposes only by *Cost Recovery Market Participants* for the duration of the separation.~~

~~(o) **[Deleted]**~~

~~(p) When *AEMO* dispatches a quantity of *regulating raise service* or *regulating lower service* in addition to the quantity it determines in accordance with the *dispatch algorithm*, *AEMO* must:~~

~~(1) for the purposes of paragraphs (f) and (g), include the additional quantity in the cost of *delayed services*; and~~

~~(2) for the purposes of paragraphs (h) and (i), exclude the additional quantity in the cost of *regulation services*,~~

~~taking into account the requirements in clauses 3.8.1(a) and (b) to maximise the value of *spot market* trading.~~

3.15.6AA ~~[Deleted]~~Frequency performance payments and cost recovery for regulation services

Definitions

(a) In this clause:

appropriate metering means metering to allow an eligible unit's individual contribution to the aggregate deviation in *frequency* of the *power system* to be assessed, in accordance with the requirements set out in the *frequency contribution factors procedure*.

eligible unit means a *scheduled generating unit*, a *semi-scheduled generating unit*, a *scheduled bidirectional unit*, a *scheduled load,* an *ancillary service unit*, a *non-scheduled generating unit*, a *non-scheduled bidirectional unit* or a *market connection point* for a *non-scheduled load.*

Trading amount calculation for frequency performance payments

(b) In each *trading interval* in relation to:

(1) each eligible unit which has appropriate metering, an *ancillary services transaction* occurs, which results in a *trading amount* for the relevant *Cost Recovery Market Participant* determined in accordance with the following formula:

$$TA = CF \times \frac{P_{regulation}}{12} \times RCR$$

for each *trading interval* where:

TA (in $)	=	the *trading amount* payable or receivable by the *Cost Recovery Market Participant;*
CF (a number)	=	the contribution factor for the eligible unit determined by *AEMO* under paragraph (e) for the relevant *trading interval* and the *region* relevant to the *regulating raise service* or *regulating lower service*;
$P_{regulation}$ (in $ per MW per hour)	=	the *ancillary service price* for the *regulating raise service* or *regulating lower service* in that *trading interval* for that *region*; and
RCR (in MW)	=	the requirement for corrective response determined by *AEMO* under subparagraph (g)(6).

(2) each eligible unit which does not have appropriate metering, an *ancillary services transaction* occurs, which results in a *trading amount* for the relevant *Cost Recovery Market Participant* determined in accordance with the following formula:

$$TA = RCF \times \frac{P_{regulation}}{12} \times RCR \times \frac{TE}{ATE}$$

for each *trading interval* where:

TA (in $)	=	the *trading amount* payable by the *Cost Recovery Market Participant*;
RCF (a number)	=	the aggregate residual contribution factor for eligible units that do not have appropriate metering, for the relevant *trading interval* and the *region* relevant to the *regulating raise service* or *regulating lower service*, having regard to the principle in paragraph (f)(3);
$P_{regulation}$ (in $ per MW per hour)	=	the *ancillary service price* for the *regulating raise service* or *regulating lower service* in that *trading interval* for that *region*;
RCR (in MW)	=	the requirement for corrective response determined by *AEMO* under subparagraph (g)(6).
TE (in MWh)	=	the sum of the absolute value of any *adjusted gross energy* amount, for the *Cost Recovery Market Participant* for an eligible unit that does not have appropriate metering, for the *trading interval* in the *region* relevant to the *regulating raise service* or *regulating lower service*; and
ATE (in MWh)	=	the aggregate of the absolute value of *adjusted gross energy* amounts for all *Cost Recovery Market Participants*, for eligible units that do not have appropriate metering, for the *trading interval* for the *region* relevant to the *regulating raise service* or *regulating lower service*.

Cost recovery for regulation services used

(c) In each *trading interval* in relation to:

(1) each eligible unit which has appropriate metering, an *ancillary services transaction* occurs, which results in a *trading amount* for the relevant *Cost Recovery Market Participant* determined in accordance with the following formula:

$$TA = TSFCAS \times U \times NCF$$

for each *trading interval* for each *global market ancillary service requirement* and each *local market ancillary service requirement* where:

TA (in $)	=	the *trading amount* payable by the *Cost Recovery Market Participant*;
TSFCAS (in $)	=	each amount calculated by *AEMO* under clause 3.15.6A(h)(2) for the *regulating raise service* or the *regulating lower service* in respect of a *trading interval*;
U (a number)	=	the maximum proportion of the *dispatched regulating raise service* or *regulating lower service* used by *AEMO* in that *trading interval* (which is a number between 0 and 1); and
NCF (a number)	=	the negative contribution factor for the eligible unit determined by *AEMO* under paragraph (e) for the relevant *trading interval* and the *region* relevant to the *regulating raise service* or *regulating lower service*.

(2) in relation to each eligible unit for which the *trading amount* is not calculated in accordance with the formula in subparagraph (1), an *ancillary services transaction* occurs, which results in a *trading amount* for the relevant *Cost Recovery Market Participant* determined in accordance with the following formula:

$$TA = TSFCAS\ x\ U\ x\ NRCF\ x\ \frac{TE}{ATE}$$

for each *trading interval* for each *global market ancillary service requirement* and each *local market ancillary service requirement* where:

TA (in $)	=	the *trading amount* to be determined (which is a negative number);
TSFCAS (in $)	=	has the meaning given in subparagraph (1);
U (a number)	=	has the meaning given in subparagraph (1);
NRCF (a number)	=	the negative residual contribution factors for all eligible units that do not have appropriate metering, for the relevant *trading interval* and the *region* relevant to the *regulating raise service* or *regulating lower service*, having regard to the principle in paragraph (f)(3);
TE (in MWh)	=	has the meaning given in subparagraph (b)(2); and
ATE (in MWh)	=	has the meaning given in subparagraph (b)(2).

Cost recovery for regulation services not used

(d) In each *trading interval* in relation to:

(1) each eligible unit that has appropriate metering, an *ancillary services transaction* occurs, which results in a *trading amount* for the relevant *Cost Recovery Market Participant* determined in accordance with the following formula:

$$TA = TSFCAS \times (1 - U) \times NDCF$$

for each *trading interval* for each *global market ancillary service requirement* and each *local market ancillary service requirement* where:

TA (in $)	=	the *trading amount* to be determined (which is a negative number);
TSFCAS (in $)	=	has the meaning given in paragraph (c)(1);
U (a number)	=	has the meaning given in paragraph (c)(1);

NDCF (a number)	=	the negative default contribution factors for the eligible unit determined by *AEMO* under subparagraph (g)(4) for the relevant *trading interval* and the *region* relevant to the *regulating raise service* or *regulating lower service*.

(2) in relation to each eligible unit for which the *trading amount* is not calculated in accordance with the formula in subparagraph (1), an *ancillary services transaction* occurs, which results in a *trading amount* for the relevant *Cost Recovery Market Participant* determined in accordance with the following formula:

$$TA = TSFCAS \times (1 - U) \times NDRCF \times \frac{TE}{ATE}$$

for each *trading interval* for each *global market ancillary service requirement* and each *local market ancillary service requirement* where:

TA (in $)	=	the *trading amount* to be determined (which is a negative number);
TSFCAS (in $)	=	has the meaning given in subparagraph (1);
U (a number)	=	has the meaning given in subparagraph (1);
NDRCF (a number)	=	the aggregate of the negative default residual contribution factors for the eligible unit determined by *AEMO* under subparagraph (g)(4)(ii) for the relevant *trading interval* and the *region* relevant to the *regulating raise service* or *regulating lower service*.
TE (in MWh)	=	has the meaning given in subparagraph (b)(2); and
ATE (in MWh)	=	has the meaning given in subparagraph (b)(2).

(e) *AEMO* must determine, in accordance with the *frequency contribution factors procedure*, a contribution factor (which may be positive or negative) for each eligible unit for the purposes of clauses 3.15.6A(i) and 3.15.6AA(a) and (b).

(f) *AEMO* must develop, publish on its website, and may amend from time to time, in accordance with the *Rules consultation procedures*, the *frequency* *contribution factors procedure* for determining contribution factors to apply in each *trading interval* for use in paragraph (e), taking into account the following principles:

(1) a negative contribution factor for an eligible unit should reflect the extent to which the unit contributed to increasing the aggregate deviation in *frequency* of the *power system*;

(2) a positive contribution factor for an eligible unit should reflect the extent to which the unit contributed to reducing the aggregate deviation in *frequency* of the *power system*;

(3) the residual contribution factor for all eligible units that do not have appropriate metering must be equal across and within all classes of *Cost Recovery Market Participants*;

(4) separate contribution factors must be determined with respect to the contribution to the need to raise or lower the *frequency* of the *power system*;

(5) a contribution factor for each eligible unit must be determined by *AEMO* for every *trading interval* unless in *AEMO's* reasonable opinion it is impractical to do so;

(6) a contribution factor must be determined for each eligible unit based on the *power system frequency* measured for that *region*, unless in *AEMO's* reasonable opinion it is impractical to do so; and

(7) a contribution factor is a number between -1 and 1.

(g) *AEMO* must include in the *frequency contribution factors procedure*:

(1) the criteria for determining whether an eligible unit has appropriate metering;

(2) a formula that *AEMO* will use in each *trading interval* to calculate the measure of the need to raise or lower the *frequency* of the *power system*, in order to determine a contribution factor under paragraph (e), which:

(i) must be based on *power system frequency*;

(ii) must contain sufficient detail so that a *Cost Recovery Market Participant* can use it to estimate the need to raise or lower the *frequency* of the *power system* during each *trading interval*; and

(iii) may include parameters to be determined by *AEMO* from time to time to be applied to the different elements of the formula;

(3) the methodology *AEMO* will use to determine a contribution factor to apply to an eligible unit which reflects the relevant *Cost Recovery Market Participant's* contribution to the aggregate deviation in *frequency* of the *power system*;

(4) the methodology *AEMO* will use to determine a default contribution factor to apply to an eligible unit:

(i) where it is impractical for *AEMO* to determine a contribution factor for that unit in a *trading interval* based on the data measured for that *trading interval* under subparagraph (f)(5);

(ii) for the allocation of costs of any *enabled regulating raise service* or *enabled regulating lower service* that was not used by *AEMO* in that *trading interval* under paragraph (d); and

(5) the data *AEMO* will use to calculate the contribution factor for an eligible unit with appropriate metering, which must include the unit's *active power* output or consumption and may include:

(i) the *frequency* measured at the *connection point* for the eligible unit;

(ii) the electronic signals from *AEMO* with respect to the provision of a *market ancillary service*; and

(iii) any other data *AEMO* considers relevant;

(6) the methodology *AEMO* will use to determine the requirement for corrective response under subparagraph (b)(1), which is a measure of the total volume in MW across the *power system* that contributed to reducing the aggregate deviation in *frequency* of the *power system*; and

(7) the method *AEMO* will use to determine a reference trajectory in each *trading interval* for each eligible unit which has appropriate metering, which must be informed by:

(i) the *dispatch* target for a *scheduled generating unit, scheduled load, scheduled bidirectional unit* and *ancillary service unit* at the end of the previous *trading interval* and at the end of the *relevant trading interval*;

(ii) the *dispatch* level for a *semi-scheduled generating unit* at the end of the previous *trading interval* and at the end of the relevant *trading interval*; and

(iii) where practical, any information provided by a *Registered Participant* for a *non-scheduled generating unit* or *non-scheduled bidirectional unit* that relates to its expected trajectory over the *trading interval*,

and may be informed by:

(iv) the requirement for an *ancillary service unit enabled* for a *market ancillary service*, to respond to electronic signals from *AEMO* in relation to the provision of that *market ancillary service* within the *trading interval*; and

(v) any other factors *AEMO* determines to be relevant.

(h) AEMO may make minor or administrative amendments to the *frequency contribution factors procedure* without complying with the *Rules consultation procedures*.

(i) *AEMO* must *publish*:

(1) the default contribution factors determined under subparagraph (g)(3), at least 5 *days* before the *billing period* in which the contribution factor will apply;

(2) any parameters it determines under paragraph (g), at least 5 *business days* prior to applying those parameters;

(3) the contribution factors determined in accordance with paragraph (e), as soon as practicable after the relevant *trading interval*;

(4) the data calculated using the formula referred to in paragraph (g)(2), as soon as practicable after the *trading interval* to which it applies; and

(5) in accordance with the *timetable*, data relevant to paragraphs (a), (b) and (c) including the measured data for each eligible unit which has appropriate metering.

CHAPTER 4

4.8.16 AEMO reporting on frequency performance

(a) Each week *AEMO* must prepare and publish on its website, a report (**weekly report**) in respect of *frequency* performance outcomes for the previous week, which includes:

(1) an indicative comparison of *power system frequency* performance against the following measures specified in the *frequency operating standard*:

(i) the proportion of time that the *frequency* of the *power system* was inside of the *normal operating frequency band*;

(ii) the recovery times to return to the *normal operating frequency band* where *frequency* left the *normal operating frequency band*; and

(iii) the time error requirements;

(2) the *regulation services* that were *dispatched* by *AEMO* in each *region*; and

(3) measures indicating the proportion of *dispatched regulation services* that were used by *AEMO*.

(b) Within 30 *business days* of the end of each calendar quarter, *AEMO* must prepare and publish on its website, a report (**quarterly report**) in respect of *power system frequency* during the quarter, which includes:

(1) where applicable, *AEMO*'s assessment of the impact of any actions taken by *AEMO* to improve *power system frequency* control outcomes;

(1A) *AEMO's* assessment of the level of aggregate *frequency* responsiveness in the *power system* provided by *frequency* responsive *plant* in each *region*;

(2) *AEMO*'s assessment of the achievement of the *frequency operating standard*, including (where applicable) an analysis of how and why the *frequency operating standard* was not met;

(3) the rate of change of *power system frequency* associated with the largest *frequency* deviation, and any other significant *frequency* deviation, in each month;

(4) *AGC* estimates of the additional electrical power (in MW) required to be produced or consumed to correct a given *power system frequency* deviation (known as the 'area control error'); and

(5) a list of any reviewable operating incidents that affected *power system frequency*.

(c) Where necessary or convenient, *AEMO* may present the information in the weekly reports and quarterly reports separately for the Tasmania *region* and aggregated for the remaining *regions*.

(d) *AEMO* must publish on its website, the methodology and assumptions used by *AEMO* in preparing each weekly report and quarterly report.

10. Glossary

frequency contribution factors procedure

The procedure developed and published by *AEMO* in accordance with clause 3.15.6AA(f)~~(k)~~.

frequency performance payment

A payment made by *AEMO* to a *Cost Recovery Market Participant* in accordance with clause 3.15.6AA(b)~~(i1)~~ and the *frequency contribution factors procedure* ~~in relation to that *Market Participant's* contribution to the reduction in the aggregate need for *regulation services* over a *trading interval*~~.

trading amount

The positive or negative dollar amount resulting from a *transaction*, determined pursuant to clauses 3.15.6, 3.15.6A, 3.15.6AA or 3.15.11.

11. Savings and Transitional Rules

Clause 11.122.2 Interim Primary Frequency Response Requirements

After clause 11.122.2(d), insert the following note:

Note

The obligations on *AEMO* to publish the Primary Frequency Response
Requirements under clause 4.4.2A(a) are now set out in clause 11.[XXX].2(b).

After Part ZZZZ[X], insert:

Part ZZZZ[] Primary frequency response incentive arrangements

11.[xxx] Rules consequential on the making of the National Electricity Amendment (Primary frequency response incentive arrangements) Rule 20222~~1~~

11.[xxx].1 Definitions

For the purposes of this rule 11.[xxx]:

Amending Rule means the National Electricity Amendment (Primary frequency response incentive arrangements) Rule 20222~~1~~.

Commencement date means [date Schedule 1 of this rule commences].

new clause 3.15.6AA(~~k~~f) means clause 3.15.6AA(~~k~~f) of the *Rules* as in force on and from the Commencement date.

old clause 3.15.6A(k) means clause 3.15.6A(k) of the *Rules* as in force immediately before the Commencement date.

11.[xxx].2 Primary Frequency Response Requirements

(a) Despite clause 11.122.2(d), the interim Primary Frequency Response Requirements developed and published by *AEMO* in accordance with clause 11.122.2(a) will continue to apply until the *Primary Frequency Response Requirements* are made and published under paragraph (b).

(b) *AEMO* must develop and publish the *Primary Frequency Response Requirements* under clause 4.4.2A(a) by [date which is [6] months from the date this rule is made].

11.[xxx].3 Frequency Contribution Factors Procedure

(a) *AEMO* must develop and publish the first *frequency contribution factors procedure* required under new clause 3.15.6AA(~~k~~f) by [date that is 9 months from the date the rule is made].

(b) On and from the Commencement date the *frequency contribution factors procedure* will replace the procedure prepared and published by *AEMO* under old clause 3.15.6A(k) in its entirety, and that procedure will no longer apply.