RELIABILITY
PANEL AEMC

DETERMINATION

Reliability Panel AEMC

DRAFT DETERMINATION

REVIEW OF THE FREQUENCY OPERATING STANDARD

8 DECEMBER 2022

INQUIRIES

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CITATION

Reliability Panel, Review of the Frequency operating standard, 8 December 2022

ABOUT THE RELIABILITY PANEL

The Panel is a specialist body established by the Australian Energy Market Commission (AEMC) in accordance with section 38 of the National Electricity Law and the National Electricity Rules. The Panel comprises industry and consumer representatives. It is responsible for monitoring, reviewing and reporting on reliability, security and safety on the national electricity system, and advising the AEMC in respect of such matters.

RELIABILITY PANEL MEMBERS

Charles Popple (Chairperson), AEMC Commissioner
Stephen Clark, Marinus Link Project Director, TasNetworks
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SUMMARY

1 The transformation of the power system presents challenges and opportunities for the control of power system frequency. The reduction in prevalence of synchronous thermal generators is expected to result in reduced levels of inertia that acts to resist changes in power system frequency and keep the grid stable. At the same time, new inverter connected technologies, including renewable generation and battery energy storage systems have the capability to provide very fast active power response to changes in system frequency, if they are configured to do so.

2 The Reliability Panel (Panel) considers that the draft frequency operating standard (FOS) will help promote the National Electricity Objective (NEO) and is in the long-term interests of consumers. In particular, the draft FOS manages the trade-off between the benefits of a secure and resilient power system and the costs of achieving this.

3 The Panel has reviewed the FOS which specifies the required frequency outcomes that AEMO must meet in the NEM under different operating conditions. The Panel considers that the additions and amendments to the FOS are crucial to maintaining system security in the context of a rapidly transitioning power system.

4 Stable operation of the power system requires that frequency be maintained close to a nominal target of 50 Hz. This frequency is essentially a measure of the speed of rotating machinery connected to the power system. When generation is equal to load, the frequency will be stable. However, when there is a mismatch between instantaneous demand for electricity and the instantaneous power supplied by generators, system frequency will diverge from 50Hz.

5 Power system equipment, including generators and associated plant may disconnect from the power system if the system frequency becomes unstable and changes too quickly, or varies too far from 50Hz. This can result in the separation of regions from the NEM, disconnection of load and, in the worst cases, the collapse of all or part of the power system, known as a black system event.

6 The Panel has made a draft FOS for the mainland and Tasmania which responds to a number of issues that were identified in the issues paper for this review. The draft determination comprises three main sections that propose additions and amendments to the FOS to support power system security and deliver reduced costs for consumers over the long-term.

7 The Panel is seeking feedback on the draft determination and draft FOS by **2 February 2023**. There are a variety of ways to provide feedback, including participating in our public forum, through bilateral meetings, and through the provision of formal submissions.

The core elements of the draft FOS

8 The key features of the draft FOS, attached in appendix C, are:

- Updated settings for contingency events — including limits in the FOS for the rate of change of frequency following contingency events

- Confirmation of the allowable ranges for frequency during normal operation, the primary frequency control band (PFCB) and that the target frequency is 50Hz.
- Removal of the limit for accumulated time error.

9 Each of these elements of the draft FOS is described further below.

Required frequency outcomes following contingency events

10 The draft FOS includes a number of updates and changes with respect to the required frequency outcomes for contingency events. These include:

- **New requirements for the allowable rate of change of frequency (RoCoF)** following credible and non-credible contingency events. This new standard would reflect the system operating limits in the face of the expected reduction in inertia provided by synchronous generators as the generating fleet becomes increasingly dominated by inverter-based renewable generation. The draft FOS includes separate RoCoF requirements for the mainland and for Tasmania. This reflects the different operational characteristics in each of these asynchronous regions. The draft includes provisions that would require that:
  - following a credible contingency event, RoCoF must not be greater than:
    - Mainland: 0.5Hz measured over any 500ms (1Hz/s)
    - Tasmania: 0.75Hz measured over any 250ms (3Hz/s)
  - following a non-credible contingency event, or multiple contingency event that is not a protected event, AEMO should use reasonable endeavours to maintain RoCoF within:
    - Mainland: 0.9Hz measured over any 300ms (3Hz/s)
    - Tasmania: 0.9Hz measured over any 300ms (3Hz/s)
- **Extension of the existing 144MW limit for generation events in Tasmania to also apply for load and network events.** This change would reflect the challenge associated with operating the Tasmanian power system including the expected interest in the connection of large commercial and industrial loads such as hydrogen electrolysers and data centres.
- **No requirement in the FOS to limit the size of contingency events in the mainland.** While AEMO has identified an expectation for increasing operational risks associated with the connection of large generators and loads in the Mainland NEM, AEMO advised that the existing arrangements under the NER are sufficient for AEMO and TNSPs to manage these risks. AEMO's advice notes that the introduction of a limit in the FOS on the maximum allowable size for a credible contingency event would be a relatively inflexible mechanism that would likely not reflect the variability of the hosting capacity for the mainland grid between regions and over time.
- **Renaming of the "supply scarcity" operating condition to "system restoration"** to better reflect the purpose of this part of the FOS. AEMO's advice confirms that the existing settings in the FOS that apply during system restoration reflect the expected operating conditions while the power system is being restored following a major

contingency event that results in automatic disconnection of load. The existing settings allow for the accelerated reconnection of customer load, as compared to the FOS for interconnected operation.

Required frequency outcomes during normal operation

11 The draft FOS maintains the current allowable ranges for frequency during normal operation through the normal operating frequency band (NOFB) and the normal operating frequency excursion band (NOFEB). It also confirms the primary frequency control band (PFCB) as 49.985Hz — 50.015Hz, consistent with the current setting in the NER. The PFCB relates to the sensitivity for the provision of mandatory primary frequency response (PFR).

12 The draft FOS also includes additional confirmation that the target frequency for the power system is 50Hz, consistent with the engineering assumptions that underpin the power system.

13 This element of the draft determination is supported by advice from AEMO and the results of power system modelling undertaken by GHD which shows that provision of narrow band PFR by the bulk of the generation fleet delivers effective control of system frequency, increased power system resilience, and reduced aggregate costs for frequency control.

14 The Panel notes stakeholder concerns in relation to the enduring nature of mandatory PFR as part of the NEM regulatory framework. Some stakeholders expressed a desire that the mandatory arrangements sunset at some future date, following further development and refinement of alternative market and incentive arrangements for narrow band PFR.[1] Others accepted the enduring value of mandatory PFR, but advocated for review and potential widening of the PFCB, based on detailed technical and economic analysis.[2]

15 This review of the settings in the FOS for normal operation follows on from the AEMC's final determination for *Primary frequency response incentive arrangements*. The AEMC's final rule confirmed mandatory PFR as an enduring requirement for all scheduled and semi-scheduled generators in the NEM and implemented new arrangements for frequency performance payments to value helpful frequency response. The new frequency performance payments arrangements are set to commence from 8 June 2025.

16 The Panel's draft determination is limited in scope to the operational parameters set out in the FOS. While this includes consideration of the appropriate setting for the PFCB, it does not extend to consideration of the detailed requirements set out in the NER, including the operational frequency control requirements set out in cl 4.4.2 of the NER.

17 At the same time, the Panel recognises that there is value in a follow-up review of the settings in the FOS for normal operation, including the PFCB at a later date, following a suitable period of operational experience with the frequency performance payments arrangements in effect. Therefore, the Panel recommends that a subsequent review of the FOS commence in the first half of 2027, two years after the commencement of the frequency performance payments arrangements. Among other things, this subsequent review will

1 For example, submissions to the Issues paper: CS energy p.10.; Snow Hydro, p.2.

2 For example, submissions to the Issues paper: AEC, p.3.; Energy Australia pp.2-3.

provide an opportunity to assess the impact of the frequency performance payments arrangements and whether it would then be appropriate to revise any of the settings in the FOS for normal operation.

Removal of a quantified limit on accumulated time error

18 The draft FOS removes the limit on accumulated time error while retaining the requirement for AEMO to monitor and report on time error. This change would remove the obligation on AEMO to maintain time error within a preset range which would provide AEMO with the flexibility to adjust its systems over time.

Proposed implementation arrangements

19 The Panel proposes that, following the publication of the final determination by **7 April 2023**, the revised FOS would take effect on **9 October 2023.** This aligns with the commencement of the new market ancillary service arrangements for very-fast contingency FCAS. The Panel understands that the new requirements in the FOS for managing RoCoF following contingency events would help AEMO determine pre-contingent inertia levels as an input to determining the required volume of very-fast FCAS.

HOW TO MAKE A SUBMISSION TO THIS PROCESS

We encourage you to make a submission

Stakeholders can help shape the solution by participating in the Panel's review process. Engaging with stakeholders helps us understand the potential impacts of our decisions and, in so doing, contributes to well-informed, high-quality outcomes.

How to make a written submission

Due date: Written submission responding to this draft determination and draft FOS must be lodged with the Panel by: **2 February 2023**.

How to make a submission: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code **REL0084.**[3]

Tips for making submissions on draft determinations are available on our website.[4]

Publication: The Panel publishes submissions on its website. However, we will not publish parts of a submission that we agree are confidential, or that we consider inappropriate (for example offensive or defamatory content, or content that is likely to infringe intellectual property rights).[5]

Next steps and opportunities for engagement

There are other opportunities for you to engage with us, such as one-on-one discussions or industry briefing sessions.

The Commission recognises that this is a substantive change to the market design and is therefore keen to undertake substantial stakeholder consultation in order to test and gain input. This will occur in a number of formats. Stakeholders are invited to register for each event via the Commission's website.

Table 1: **Key milestones and opportunities for engagement**

ITEM	DESCRIPTION	DATE
Public forum on draft determination and draft FOS	The public forum will be an information session, providing an overview of the draft determination and the proposed FOS to assist with understanding and engagement.	15 December 2022
Submissions close for draft determination and draft FOS	Written submissions responding to this draft determination and rule must be lodged with Commission by this date as per the 'How to make a	2 February 2023

3 If you are not able to lodge a submission online, please contact us and we will provide instructions for alternative methods to lodge the submission.

4 See: https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/our-work-3.

5 Further information is available here: https://www.aemc.gov.au/contact-us/lodge-submission.

ITEM	DESCRIPTION	DATE
	written submission' instructions above.	

In addition, we are happy to meet bilaterally with any interested party, or answer any questions or feedback at any stage.

You can also request the Commission to hold a public hearing in relation to this draft determination.[6]

Due date: Requests for a hearing must be lodged with the Commission by 22 December 2022.

How to request a hearing: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code **REL0084.** Specify in the comment field that you are requesting a hearing rather than making a submission**.**[7]

For more information, you can contract us

Please contact the project leader with questions or feedback at any stage.

Project leader: Ben Hiron

Email: ben.hiron@aemc.gov.au

Telephone: (02) 8296 7855

6 Refer to s.101. of the NEL.

7 If you are not able to lodge a request online, please contact us and we will provide instructions for alternative methods to lodge the request.

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APPENDICES

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FIGURES

1 THE RELIABILITY PANEL HAS MADE A DRAFT DETERMINATION

The Reliability Panel is responsible under the National Electricity Rules (the Rules) for determining the power system security standards, including the frequency operating standard (FOS). The draft determination is to update the FOS which applies to the national electricity system, including the NEM mainland and Tasmania.[8]

We are seeking feedback on this draft determination.

The Panel's draft determination has been informed by technical advice provided by AEMO — as required by NER Clause 8.8.1(a)(2) — and independent analysis and advice provided by GHD. Further detail on the consultation and policy development process for the review is provided in appendix A.

The Panel's assessment of this draft determination against the assessment criteria and the national electricity objective is set out in chapter 2. The draft FOS (in mark-up form) is included in appendix C and a clean copy is published separately.

This chapter provides:

- Section 1.1 - An overview of the changes in the draft FOS and the high level reasoning for these
- Section 1.2 - A summary of how stakeholder feedback has shaped the draft FOS
- Section 1.3 - An overview of the interactions between this draft determination and other current and upcoming market reforms.

1.1 Changes in the draft FOS

This section summarises the key features of the draft FOS, attached in appendix C. It outlines the:

- Section 1.1.1 - Settings in the draft FOS for the required frequency outcomes following contingency events, this includes the addition of new RoCoF requirements
- Section 1.1.2 - Settings in the draft FOS for normal operation along with the consideration of the appropriate setting for the PFCB that relates to the sensitivity of mandatory PFR provided by scheduled and semi-scheduled generators
- Section 1.1.3 - Changes in the draft FOS in relation to accumulated time error.

1.1.1 Settings for contingency events

The settings in the draft FOS that relate to the frequency outcomes following contingency events include:

8 The national electricity system comprises the combined electricity grids for Queensland, New South Wales, Victoria, South Australia and Tasmania. The electricity systems for Western Australia (SWIS) and the Northern Territory are operated separately and are not covered by the NEM FOS.

- New requirements, in the mainland and Tasmania, to maintain RoCoF following credible and non-contingency events within acceptable levels, based on the technical capability of the generation fleet.
- Extending the existing 144MW limit for generation events in Tasmania to also apply for load and network events.
- No requirement in the FOS to limit the size of contingency events in the mainland
- Renaming the "supply scarcity" operating condition to "system restoration".

An overview of each of these elements of the draft FOS is provided below and further detail is included in chapter 3.

A requirement to manage RoCoF following contingency events

The draft FOS includes new requirements for how AEMO manages the rate of change of frequency following credible and non-credible contingency events. These new elements of the FOS define the safe operating envelope for the power system in the context of the ongoing reduction in system inertia due to the progressive retirement of synchronous thermal generators. In the short term, the specification of limits for RoCoF would support the implementation of the new market ancillary service arrangements for fast frequency response services (very fast raise and very fast lower services). Over the longer term, these limits will also support the development of future arrangements to provide RoCoF control services including through synchronous and synthetic inertia. As such, this change to the FOS would assist with the valuation and procurement of essential system services to manage post-contingency RoCoF, thereby supporting efficient investment in and operation of energy resources.

RoCoF requirements for the mainland

Following a credible contingency event, RoCoF must not be greater than 0.5Hz measured over 500ms (1Hz/s). This value is driven by AEMO's assessment of the RoCoF ride-through capability of legacy plant within the current generation fleet and is consistent with the findings from GHD's survey of international approaches to RoCoF management.

Following a non-credible contingency event or multiple contingency event that is not a protected event, AEMO should use reasonable endeavours to maintain RoCoF within 0.9Hz measured over any 300ms (3Hz/s). This value aligns with the range of RoCoF that support the satisfactory operation of emergency frequency control schemes in the mainland NEM, based on technical advice and analysis provided by AEMO.

RoCoF requirements for Tasmania

Following a credible contingency event, RoCoF must not be greater than 0.75Hz measured over 250ms (3Hz/s). This value is driven by AEMO's assessment of the RoCoF withstand capabilities of the predominantly hydroelectric powered Tasmanian grid. AEMO's advice confirms that hydroelectric generators have much greater RoCoF ride-through capability when compared to thermal generators.

Following a non-credible contingency event or multiple contingency event that is not a protected event, AEMO should use reasonable endeavours to maintain RoCoF within 0.9Hz measured over any 300ms (3Hz/s). This value aligns with the existing dynamic UFLS approaches implemented in Tasmania. Advice provided by AEMO and TasNetworks supports the introduction of these limits that try to compensate for the complexities of safely operating the Tasmanian network.

Extension of the limit on the size of credible contingency events in Tasmania

The draft FOS extends the existing 144MW limit for generation events in Tasmania to also apply for load and network events. Supported by advice from AEMO, this change reflects the particular challenges associated with operating the Tasmanian power system including its relative small size and the scarcity of fast-acting contingency reserves.[9] TasNetworks proposed the extension of the limit on the largest contingency event to help manage the risks associated with the connection of large commercial and industrial loads such as hydrogen electrolysers and large-scale data centres.[10]

The extension of the existing 144MW limit to cover all types of credible contingency events in the Tasmanian region provides a consistent and transparent indication of the safe operating range for the Tasmanian power system. Given the particular operational challenges for the Tasmanian region, this element of the draft FOS aligns with operational practise in Tasmania and would provide transparency as to the hosting capacity of the Tasmanian grid for both generation and load connection applications.

No requirement to limit the size of contingency events in the mainland

The draft FOS does not include a limit on the maximum allowable credible contingency event in the mainland. While AEMO is expecting a range of potential future developments in the mainland power system that have the potential to test the hosting capacity of the mainland grid, its advice is that a limit on the maximum size of a credible contingency in the FOS is not justified at this time. In its advice, AEMO noted that it may be difficult for the specification of a limit in the FOS to adequately reflect the geographical variation of the network hosting capacity and how this may change over time. AEMO's view is that it may be more appropriate for operational issues related to the connection of large generators and loads to be managed by AEMO and TNSPs directly.[11]

Change in the name of the requirement for system restoration

The Panel has determined to rename the settings for "supply scarcity" to "system restoration" to better reflect the purpose of the additional settings to accelerate the reconnection of load when restoring the system following a significant system disruption. This change responds to stakeholder concerns in relation to the application of the operational frequency tolerance band (OFTB) for supply scarcity on the requirements for connecting generators. Importantly,

9 AEMO, Advice for Reliability Panel's Review of Frequency Operating Standard, 8 December 2022, p.51.

10 TasNetworks, Submission to the Issues paper, 6 June 2022, p.5.

11 AEMO, *Advice to the Reliability Panel for the review of the frequency operating standard*, September 2022, p.52.

the Panel's changes retain the connection obligation on generators to show the capability of operating between 48 – 52 Hz for the recovery time of 10 minutes.

1.1.2 Settings for normal operation and the primary frequency control band

The Panel has reviewed the settings in the FOS that apply for normal operation — in the absence of contingency events — and the setting for the primary frequency control band (PFCB) that relates to the sensitivity of PFR provided by scheduled and semi-scheduled generators in the NEM. The draft FOS:

- Maintains the current settings for the allowable range of frequency during normal operation. For interconnected operation in the mainland and Tasmania:
  - the normal operating frequency band (NOFB) is maintained as 49.85 – 50.15Hz
  - the normal operating frequency excursion band (NOFEB) is maintained as 49.75 – 50.25Hz
- Sets the PFCB at 49.985 – 50.015Hz. This is consistent with the initial setting for the PFCB in the NER.
- Includes a requirement that the target frequency in the NEM is 50Hz. This aligns with the one of the fundamental principles for operation of the power system and reflects AEMO's operational practises.

An overview of this element of the draft FOS is provided below and further detail is included in chapter 4.

Consistent with stakeholder responses to the issues paper, the key focus of the Panel's consideration for this element of the FOS has been the analysis of the costs and benefits associated with different settings for the PFCB that directly relates to the expected range of power system frequency during normal operation. The Panel's draft determination is informed by advice from AEMO and detailed power system modelling undertaken by GHD to study the operational and economic impacts associated with varying the PFCB.

A narrow setting for the PFCB delivers improved power system resilience

The Panel's draft determination is supported by advice from AEMO that the existing settings for the PFCB and normal operation are necessary to maintain effective control of frequency that is fundamental to a secure and resilient power system. Analysis undertaken for the Panel by GHD provides further evidence that narrower settings for the PFCB are expected to deliver a more secure and resilient power system. This increase in system resilience due to narrow PFCB settings is demonstrated through expectations for reduced load shedding following significant non-credible contingency events, and a significant increase in the likelihood of re synchronisation for islanded regions following such separation events.

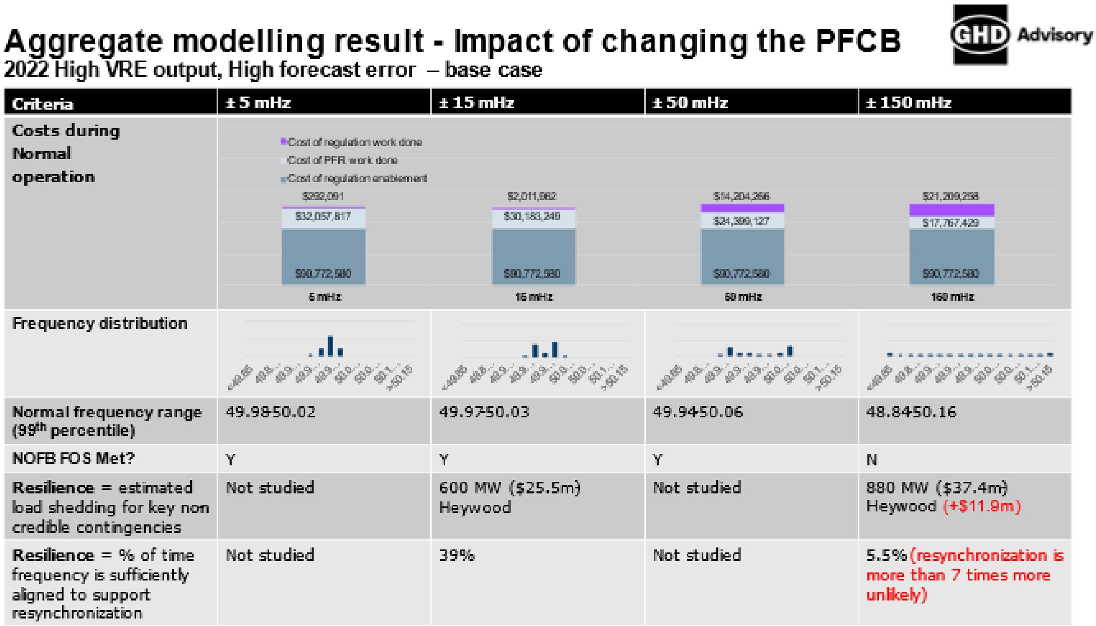
A narrow setting for the PFCB delivers lower total costs for controlling system frequency

The GHD analysis also predicts that narrower settings for the PFCB would deliver lower total costs for control of power system frequency. The expected reduction in costs for narrower PFCB settings accounts for the costs of both PFR and regulation FCAS which work together to control frequency during normal operation.

The GHD analysis predicts that wider settings for the PFCB would result in degradation of frequency performance, consistent with operational experience in the NEM during the period 2015 – 2020. Wider PFCB settings were also expected to result in lower costs for work done by generators through automatic PFR. However, costs associated with work done by regulation services were shown to increase for wider PFCB settings, more than offsetting any reduction in costs for PFR.

The high level results from the GHD analysis are shown below in Figure 1.1.

Figure 1.1: Summary of results for GHD PFCB analysis - High VRE, High Forecast error



Aggregate modelling result - Impact of changing the PFCB
2022 High VRE output, High forecast error – base case

Criteria	± 5 mHz	± 15 mHz	± 50 mHz	± 150 mHz
Costs during Normal operation	$292,091 $32,057,817 $90,772,580 5 mHz	$2,011,962 $30,183,249 $90,772,580 15 mHz	$14,204,266 $24,399,127 $90,772,580 50 mHz	$21,209,258 $17,767,429 $90,772,580 150 mHz
Frequency distribution				
Normal frequency range (99th percentile)	49.9850.02	49.9750.03	49.9450.06	48.8450.16
NOFB FOS Met?	Y	Y	Y	N
Resilience = estimated load shedding for key non credible contingencies	Not studied	600 MW ($25.5m) Heywood	Not studied	880 MW ($37.4m) Heywood (+$11.9m)
Resilience = % of time frequency is sufficiently aligned to support resynchronization	Not studied	39%	Not studied	5.5% (resynchronization is more than 7 times more unlikely)

Source: GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.iii

The settings for normal operation should be reviewed again in 2027

The Reliability panel recognise there is a necessity for narrow band PFR to control frequency close to 50Hz. Under the current arrangements, there is a reliance on Mandatory PFR to deliver this narrow band control. The frequency performance payment arrangements which commence from 8 June 2025 are expected to provide an incentive for the provision of narrow band PFR beyond and in addition to the mandatory requirement. The Panel recognises that it would be appropriate to review the settings in the FOS for normal operation, including the PFCB, again at a future date. This future review would be able to account for the rapid rate of change in the power system and also to review the economic and operational outcomes following on from the commencement of the new frequency performance payments arrangements.

The Panel considers that a subsequent review of the FOS could commence in the first half of 2027, which would allow for a period of almost 2 years to monitor the impacts of the frequency performance payments arrangements and inform further consideration of the PFCB and the settings in the FOS for normal operation. Further commentary on this follow up review for the FOS is included in section 1.3.3.

1.1.3 Accumulated time error

The draft FOS removes the quantitative limit on accumulated time error while retaining a requirement for monitoring and reporting obligations.

Time error is a measure of the accumulated time the power system has spent away from the nominal frequency target of 50 Hz. Advice from AEMO and GHD indicate that time error accumulation has minimal impact on market participants and consumers. At the same time, the existing requirement in the FOS for time error not to exceed 15 seconds drives additional procurement of regulation FCAS and the practise of time error correction which result in increased costs for operating the power system. AEMO estimates that the cost of procuring additional regulation services to respond to time error is in the order of $1.9M — $2.8M per year.

The requirement to monitor and report on time error would continue to provide value to stakeholders as measure of system frequency performance, while the FOS would no longer set any hard limits on the allowable range for accumulated time error. This would provide AEMO with more flexibility in relation to how it manages time error and would allow system changes over time to support reductions in associated costs due to time error correction.

Further detail on this element of the draft FOS is included in chapter 5.

1.2 The Panel's draft determination has taken into account stakeholder input

The Panel published an Issues paper for the review on 28 April 2022 and received eleven submissions from interested stakeholders representing industry bodies, TNSPs/DSNPs and generators. Stakeholders expressed general support for the review and the issues identified by the Panel for consideration.

The following sections describe how the draft FOS has been informed by stakeholder input, with respect to:

- The settings for contingency events, including the new standard for RoCoF following contingency events and the concept of limiting the size of the maximum allowable credible contingency event.
- The target and allowable range for frequency during normal operation and the associated setting for the PFCB that relates to the sensitivity of PFR provided by scheduled and semi-schedule generators
- The treatment of accumulated time error.

1.2.1 Settings for contingency events

The Panel's consideration on each of these issues has taken account stakeholder input, as set out below.

Stakeholders expressed support for including RoCoF limits in the FOS — subject to further detailed analysis

The limits in the draft FOS for RoCoF have been informed by technical advice provided by AEMO and a survey of international approaches to managing RoCoF undertaken by GHD. This approach to the development of RoCoF limits is consistent with stakeholder views that indicated support for the inclusion of standards for RoCoF following contingency events — subject to further analysis and consultation on the detail of such settings.

The RoCoF limit in the draft FOS for the mainland NEM has been informed by AEMO's assessment of the safe operating range for RoCoF based on the RoCoF withstand capability for the existing generation fleet and the capabilities of emergency frequency control schemes. This is consistent with the views expressed by the AEC and CS Energy that, in setting a limit for system RoCoF, the Panel should take into account the capability of existing generators and the performance of UFLS.[12]

The Panel is interested in receiving stakeholder feedback on the RoCoF limits included in the draft FOS for Tasmania and the mainland. Further detail on this element of the draft FOS is set out in section 3.1.

Stakeholders expressed support for maintaining the existing contingency containment bands in the FOS

Supported by AEMO's advice, the draft FOS maintains the current allowable ranges for frequency following contingency events, including the existing containment, stabilisation bands and recovery bands and associated timings. This draft determination aligns with stakeholder views, that note the existing contingency containment settings appear to be fit for purpose.[13]

Stakeholders expressed a range of views on the limit for the maximum allowable credible contingency event in Tasmania

In the draft FOS, the Panel has confirmed the Tasmanian maximum allowable credible contingency event limit at 144MW. Stakeholders submitted mixed responses to the consideration of the limits in the FOS. Woolnorth Renewables, the owner of the affected Musselroe Wind Farm, supported an increase in the limit to 155MW, while TasNetworks recommended the Panel extend it to include network and load events due to the small size of Tasmanian grid and the limited availability of fast FCAS in the region.[14]

A summary of the Panel's consideration of the issue is provided in section 3.2.

The Panel considered whether it would be viable to increase the limit on the size of the largest credible contingency event in Tasmania, as proposed by Woolnorth Renewables, and notes the reasoning provided in its submission to the issues paper. Raising the current limit from 144MW to 155MW would allow for the Musselroe windfarm — owned by Woolnorth Renewables — to operate unconstrained at all times, as was the case during the period July

12 Submissions to the issues paper: AEC, p.4; Ergon Energy & Energex, p.1.

13 Submissions to the Issues paper, AEC, p.4.; Ergon Energy & Energex, pp.2-3.; TasNetworks, pp.1-2,5.

14 Submissions to the issues paper: Woolnorth Renewables, pp.1-2, TasNetworks, pp.5-6.

2013 to January 2020.[15] The Panel understands that a new generator contingency scheme commenced operation in Tasmania in December 2021, allowing Musselroe windfarm to operate without constraint when sufficient load tripping services are available.[16]

Stakeholders urged caution in relation to the potential application of a limit on maximum allowable contingency events for the mainland

In line with the AEMO advice, the Panel has decided not to apply a limit on credible contingency size in the mainland. This outcome was supported by stakeholder submissions to the issues paper, who raised the inflexibility of such a limit in the FOS and concerns that it may dissuade investment in larger generation plant.[17] However, the AEC did recognise that such a limit could deliver improved transparency for new connections when compared to the existing connection process.[18]

A summary of the Panel's consideration of the issue is provided in section 3.3.

Some stakeholders raised some concerns in relation to the FOS that applies for supply scarcity

The Panel's assessment of the FOS that applies during supply scarcity was triggered by concerns raised by stakeholders that queried the appropriateness of the current settings in the FOS that apply for the purpose of load restoration at times of supply scarcity.[19] The draft FOS maintains the quantitative settings for this element of the FOS while changing the name from "supply scarcity' to "system restoration" to better reflect the expected operation situation for which this element of the FOS applies.

A summary of the Panel's investigation of this issue is provided in section 3.4.2.

1.2.2 The settings in the draft FOS for normal operation and the PFCB have been informed by quantitative analysis on the associated costs and benefits

The Panel is aware of a wide range of stakeholder views in relation to the settings in the FOS that apply during normal operation and the interaction of these with the PFCB that relates to the sensitivity for mandatory PFR provided by scheduled and semi-scheduled generators. Stakeholders generally accept that frequency performance in the NEM has improved significantly following the introduction of mandatory narrow band PFR and the initial narrow setting in the NER for the PFCB of 49.985 – 50.015Hz.[20]

Some stakeholders consider that the operational outcomes associated with the current settings should be maintained — i.e. that the operational and resilience benefits justify frequency being controlled as close as is reasonably practical around 50Hz.[21] Energy Australia noted that the current frequency performance in the NEM — relative to the NOFB — implied

15 Woolnorth renewables, Submission to the Issues paper, 6 June 2022, p.5.
16 TasNetworks, Submission to the Issues paper, 6 June 2022, p.5.
17 Submissions to the Issues paper: AEC, p.4; Delta Electricity, p.15; Origin Energy, p.2; Iberdrola, p.6.
18 AEC, Submission to the Issues paper, 9 June 2022, pp.4-5.
19 Shell Energy, Submission to the Issues paper, 9 June 2024, p.4.
20 For example, Submissions to the Issues paper: AEC, p.1; Energy Australia, p.1-2; TasNetworks,p.3.
21 For example, TasNetworks submission to the Issues paper, p.3.

that the current setting for the PFCB may be too narrow and/or that the current setting for the NOFB may be too wide.[22]

In the context of the wide range of perspectives on the optimal setting for the PFCB, many stakeholders highlighted the importance that the Panel's determination of the FOS should aim to balance the benefits of tight frequency control with the costs of achieving this outcome. Stakeholders expressed a strong desire that the Panel's consideration of the PFCB and NOFB be supported independent economic analysis.[23]

Consistent with stakeholder views, the Panel's draft determination for this element of the FOS has been informed by quantitative analysis on the costs and benefits of varying the setting for the PFCB. This analysis, undertaken by GHD, has considered the implications for system security and resilience as well as the ongoing operational costs associated with enablement and provision or regulation services and the costs of providing PFR by responsive plant.

Further detail on the Panel's consideration for this element of the draft FOS is provided in chapter 4.

1.2.3 Accumulated time error

The draft FOS abolishes the requirement for AEMO to correct for time error accumulation, but maintains the existing monitoring and reporting obligations. This outcome aligns with stakeholder views, corroborated by AEMO and GHD's survey, that correcting for time error accumulation does not materially improve power system security.[24] Moreover, in response to stakeholder feedback, the Panel has maintained the existing transparency obligations to enable the tracking and monitoring of time error accumulation as stakeholders consider it to be a valuable frequency performance metric.[25]

1.3 Paving the way for the future power system

This draft determination for the FOS is part of an ongoing program of reforms to adapt the market and regulatory arrangements to meet the needs of the future power system. There are a number of ongoing and upcoming reform processes that directly relate or overlap to some degree with the changes made by the final rule. Two particularly relevant projects include:

- the commencement of procurement arrangements for very fast FCAS from 9 October 2023 — discussed further in section 1.3.1.
- the AEMC's consideration of the *Efficient provision of inertia* rule change request — discussed further in section 1.3.2

The Panel also recommends that a subsequent review of the FOS be commenced in the first half of 2027. This next review would enable the settings in the FOS to be re-considered in

22 Energy Australia, submission to the Issues paper, pp.1-2.

23 For example, submissions to the Issues paper: AEC, pp.2-3; Delta Electricity, p.2; EnergyAustralia pp.2-3; SnowyHydro, p.1; CS Energy, pp.2-7, Shell Energy, p.3; Iberdrola, pp.2-3; Origin Energy, pp.1-2.

24 Submissions to the Issues paper: AEC, p.5; TasNetworks, pp.6-7; EnergyAustralia, p.4; Iberdrola, p.6.

25 Ibid.

light of the ongoing operational and regulatory changes in the power system, including the operational experience with the new frequency performance payment arrangements which commence on 8 June 2025. This recommendation is described further in section 1.3.3

1.3.1 The commencement of market ancillary services for very-fast FCAS

The establishment of RoCoF limits in the FOS would help AEMO establish systems for the specification and enablement of new "very-fast" contingency FCAS products which are set to commence on 9 October 2023. AEMO published a final determination for an updated market ancillary service specification on 7 October 2022, including new specifications for the very-fast raise and very-fast lower products.[26]

The new "very-fast" contingency products will have a 1-second response time and a 6-second delivery time, before handing over to the existing "fast" services that have a 6-second response time. While these services are not envisaged to be used to control RoCoF, it is envisaged that the definition of a RoCoF limit for credible contingency events will enable a pre-contingent volume of inertia to be determined that will help to determine the required volume of very fast FCAS to respond following a contingency event.

In accordance with the terms of reference for this review, the Panel plans on making a final determination on the FOS by 7 April 2023. This will allow for a period of at least 6 months from the date the revised FOS is determined to the date that the new market ancillary service arrangements for the very fast contingency FCAS commence.

1.3.2 Consideration of arrangements for the efficient provision of Inertia/RoCoF control services

On 15 December 2021 the AEMC received a rule change request for *Efficient provision of inertia* from the Australian Energy Council (AEC). The AEMC has not yet initiated the consultation process for this rule change request.

The Panel notes that the RoCoF limits included in the draft FOS provide an important input into the Commission's assessment of the AEC rule change request. As set out in the issues paper, the Panel notes that the initial post-contingent RoCoF is a function of contingency size and the level of inertia present on the power system.[27] Therefore, defining a RoCoF limit helps to better define the required frequency outcomes and therefore support ongoing efforts by AEMO to "research the application and benefits of physical and synthetic inertia" in the power system.[28]

1.3.3 The Panel recommends a follow-up review of the FOS in 2027

The Panel recommends that a follow-up review of the FOS be planned to commence in the first half of 2027. This timing would allow for further consideration of:

- the settings in the FOS for normal operation, including the NOFB, NOFEB and PFCB in the context of the new frequency performance payments arrangements that commence on 8

26 Refer to: https://aemo.com.au/consultations/current-and-closed-consultations/amendment-of-the-mass-very-fast-fcas

27 Refer to section 5.1 of the Issues paper for further detail.

28 AEMO, AEMO advice: reliability Panel review of the frequency operating standard, 8 December 2022, p.42.

June 2025. The proposed timing for a follow-up review allows for a period of almost 2 years to monitor the impact of the frequency performance payments on frequency performance in the NEM, including the degree to which the incentive arrangements deliver increased voluntary PFR.

- RoCof limits in the context of power system and market developments. In addition to the interaction between the FOS review and the *Efficient provision of inertia* rule change, the Panel notes that it would be appropriate for a follow-up review of the FOS to consider the system RoCoF limits in the context of the predicted rapid change to the generation fleet over the coming years. This subsequent review would consider whether the technical capabilities of power system plant support adjustment of the RoCoF limits included in the draft FOS.
- the settings in the FOS for Tasmania, including the limit on the largest allowable credible contingency event in Tasmania in the context of power system and market developments. The future developments that have the potential to shift the operating envelope in Tasmania include:
    - commencement of market ancillary service arrangements for very fast contingency services from 9 October 2023
    - detailed system planning to integrate Marinus Link into the Tasmania system. The 2022 ISP identifies the Marinus Link as an actionable project to provide a second DC inter-connector between Tasmania and the mainland NEM. Stage 1 is scheduled for commissioning in mid-2029, followed by stage 2 in mid 2031.[29]

The Panel is interested in stakeholder feedback on the timing and scope for the next review of the FOS.

29 AEMO, 2022 Integrated system plan, 30 June 2022, p.13.

2 THE DRAFT FOS WILL CONTRIBUTE TO THE NATIONAL ELECTRICITY OBJECTIVE

BOX 1: KEY POINTS IN THIS SECTION

- The Panel determined that the draft FOS is in the long-term interests of consumers. The Panel's determination aims to contribute to meeting the National Electricity Objective (NEO) by managing the trade-off between the benefits of a secure and resilient power system and the costs of achieving this.
- The Panel considers that the additions and amendments to the FOS are crucial to help maintain system security in the context of a rapidly transitioning electricity network. This aligns with stakeholder submissions that emphasised the need to closely reexamine the settings in the FOS in light of increasing operational risks throughout the system.
- The Panel's determination is based on the assessment principles outlined in the issues paper.

This section explains why the Panel has made its draft determination and the accompanying draft FOS. This section includes:

- Section 2.1 - The Panel has made its determination in line with the energy objective
- Section 2.2 - Considering the changes in the draft FOS against the assessment criteria
- Section 2.3 - The draft FOS and the assessment principles.

2.1 The draft determination is in line with the energy objective

In accordance with the terms of reference for the review, the Panel's draft determination is guided by the National Electricity Objective (NEO).[30] The NEO is set out in the NEL as being:[31]

BOX 2: THE NEO

"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 -

- price, quality, safety, reliability, and security of supply of electricity; and
- the reliability, safety and security of the national electricity system."

The Panel is satisfied that the proposed amendments to the FOS would be likely to contribute to the achievement of the NEO. The changes would help support the security of the

30 Section 88 of the NEL.
31 Section 7 of the NEL.

transitioning power system and deliver reduced costs for frequency control over the long term by providing AEMO with the crucial operational tools.

For further information on the Panel's decision-making process please refer to:

- Appendix A - Consultation and development process
- Appendix B - Background and context.

2.2 Considering the changes in the draft FOS against the assessment criteria

In reviewing the frequency operating standard, the Panel has considered how changes are likely to promote the NEO. The Panel identified the following assessment criteria to support that objective:

- **Promoting power system security -** the power system is in a satisfactory operating state when it is operated within specified technical operating limits, including voltage and other stability limits.[32] Maintaining the NEM power system within these technical limits allows it to operate effectively and efficiently. Operating the system within these technical limits supports the safe and secure operation of the national electricity system. This is central to maintaining the safety of consumers with respect to the physical national electricity system. The Panel has considered how the settings in the FOS specify and support safe and secure power system operation.
- **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 control should recognise the technical and financial capability of different types of market participants to respond to changes in frequency. Where practical, operational and investment risks should be borne by active market participants who are better able to manage them. The Panel has considered how the specification of settings of the FOS would likely allocate risks among market participants.
- **Efficient investment in, and operation of, energy resources to promote secure supply -** to maintain the safety and security of the national electricity system, AEMO procures ancillary services and operates the system to keep it within specific limits, generators operate and maintain their units in accordance with performance standards, and network service providers maintain and operate their networks in accordance with system standards. These activities come at a cost in terms of obligations faced by participants and AEMO. The Panel has considered how the settings of the FOS would be likely to impact on the costs incurred by different participants in maintaining the security of the system.
- **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.

32 Clause 4.2.2 of the NER.

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.
- **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.
- **Consumer preferences -** regulatory arrangements should take into account consumer preferences. This includes consideration of the costs and benefits to consumers and the impacts on the consumer experience and delivery of power system services.

The rest of this section explains why the draft FOS would promote the long-term interests of consumers.

2.3 The draft FOS and the assessment principles

2.3.1 The settings in the FOS must promote power system security

The draft FOS would **promote power system security** by introducing a RoCoF standard, extending the generator event size limit in Tasmania to cover network and load events, and maintaining the current settings for normal operation.

The RoCoF standards would contribute to the satisfactory operation of UFLS and reduce the likelihood of cascading generator outages

By introducing a RoCoF standard for credible and non-credible contingency events, the Panel would be increasing the likelihood that plant have sufficient ride-through capability to continue generating and under frequency load shedding (UFLS) schemes operate as intended. Otherwise, it could be possible that a significant contingency event could lead to cascading generator outages or compromise the satisfactory operation of UFLS, leading to a black system event.

The 144MW contingency event limit helps maintain the network within its secure operating envelope

The Panel's determination would extend the 144MW generator event limit to include network and load events in Tasmania, thereby contributing to system security by maintaining the network within its technical operating envelope. The limit would also provide guidance to connecting loads, such as hydrogen electrolysers or data centres, of the safe hosting capacity of the network and ensure that the connection arrangements take into consideration the risks to system security.

The settings for normal operation and the PFCB would be confirmed by the Panel in the draft FOS. The Panel concluded that there currently is no alternative to narrow-band PFR that provides the same level of frequency control. More effective frequency control is also shown to improve the system's resilience to significant contingency events, that could otherwise result in extensive load shedding. However, given the upcoming implementation of the *PFR incentive arrangements rule*, the Panel considers that it would be appropriate to reexamine the settings once the frequency performance payments mechanism is sufficiently established.

2.3.2 The settings in the FOS must ensure that risks are borne by those best placed to manage them

The allocation of risk and accountability for investment and operational decisions should rest with the parties best placed to manage them.

AEMO is best placed to manage the operational risks arising from rising RoCoF

The introduction of a system standard for RoCoF would obligate AEMO to maintain frequency within the limits set out in the FOS thereby promoting system resilience and alleviating the risk of unreliable electricity supply for consumers. The Panel considers that AEMO is best placed to manage RoCoF due to its system security responsibilities, its overview of the power system, and its role in the procurement of ancillary services.

TNSPs and AEMO together cooperate to manage contingency risks on the mainland

The Panel has decided against introducing a maximum contingency size limit for the mainland as TNSPs and AEMO would be better placed to manage contingency risks through the connections process. Frequency is not always the limiting factor when considering connection applications and NSPs are more capable of taking into account the overall stability and safe hosting capacity of the network. Moreover, TNSPs would be more reactive to network upgrades which may increase the safe hosting capacity in a particular region.

2.3.3 The FOS should promote efficient investment in, and operation of, energy resources to promote a secure and cost-effective power supply

AEMO, generators, NSPs and other market participants all contribute to the maintenance of system security. The Panel has tried to balance the trade-off between economic costs and system security benefits to promote **efficient investment in**, and **operation of**, the power system.

Standards for RoCoF would guide the efficient procurement of ancillary services

By setting a standard for post-contingency RoCoF, the Panel would provide AEMO with guidance on the economically efficient quantity of FFR or other ancillary services that should be procured to maintain system security. Moreover, the draft FOS would introduce a wider standard for Tasmania due to the greater RoCoF withstand capabilities of hydroelectric generators, thereby recognising that the settings in the FOS should be periodically updated to reflect the changing capabilities or mix of generators.

The Panel has considered the trade-off between costs and benefits in setting the limits for RoCoF. If the system RoCoF limit were set too high, above the technical capability of elements of the generation fleet, there would be limited system security benefits, as the risk of generator disconnection following system disturbances would remain. However, if the system RoCoF limit were set too low, then it would over constrain the market resulting in excessive costs due to constraints on energy dispatch and the procurement of ancillary services. The Panel has therefore determined that the proposed settings appropriately balance system security and economic efficiency, thereby promoting efficient investment in and operation of the power system.

The FOS would extend the Tasmanian contingency size limit to include network and load events due to scarce availability of FCAS

The Panel's determination that proposes to extend the generator event limit in Tasmania to include network and load events manages the trade-off between greater economies of scale and the costs of ancillary services. In Tasmania, the availability and costs of fast FCAS is severely constrained, with the AEMO advice confirming that a higher limit would not be in the best economic interests of consumers.

Introducing a contingency size limit for the mainland could lead to inefficient operation and investment decisions

By refraining from introducing a contingency size limit for the mainland, the Panel has recognised the detrimental effect such a limit would have on an efficient allocation of investment. The potential system security benefits are not sufficient to compensate for the expected decrease in economic efficiencies. The Panel considers that the Commission may want to investigate a more explicit co-optimisation of increasing contingency size and marginal contingency FCAS costs to result in an optimal equilibrium.

The draft FOS would retain the current settings for normal operation to maintain system security at lowest aggregate costs for consumers

The Panel's decision to maintain the current settings for normal operation is driven by the need for system security to be maintained in a cost effective way. Advice by AEMO and the GHD modelling showed that retaining the current settings would result in lower aggregate frequency control costs when compared to wider deadbands.

Abolishing the requirements to correct for time error could result in reduced costs borne by consumers

The draft FOS would abolish the requirement for AEMO to correct for the accumulation of time error. The Panel determined that the costs ultimately borne by consumers were not justifiable given the lack of any security or consumer benefits.

2.3.4 Settings in the FOS should be technologically neutral

The assessment principles state that regulatory arrangements should be designed to take into account the full range of potential market and network solutions. They should **not be targeted or designed with a particular technology** in mind.

The Panel's determination and the draft FOS do not distinguish or differentiate between the treatment of different technologies. The standards are consistent for all participants and put security benefits and economic efficiencies at the centre of decision-making rather than supporting particular technologies.

2.3.5 Settings in the FOS should be flexible in changing market and external conditions, including the decarbonisation of the power system

Regulatory arrangements must be **flexible to changing market and external conditions**. They must remain effective in achieving security outcomes over the long-term in a changing market environment. As such, the Panel's determination aligns with the generation mix and operational conditions of both Tasmania and the mainland.

The RoCoF standard, introduced by the Panel, would differentiate between the mainland and Tasmania to account for the greater RoCoF withstand capabilities of hydroelectric generators. The Panel considers that the settings should be flexible and periodically updated to reflect the change in generator mix and UFLS performance in order to re-optimise the trade-off between security and economic efficiency.

Despite proposing to confirm the settings for normal operation, the Panel remains flexible to reexamining the settings following the implementation of the primary frequency response incentive arrangements rule, as it is expected that the introduction of frequency performance payments will have a material impact on the cost-benefit analysis.

2.3.6 Settings in the FOS should be transparent, predictable and simple

The draft FOS proposed by the Panel should promote transparency and be predictable and simple so that market participants can make informed and efficient investment and operational decisions.

The 144MW contingency size limit in Tasmania provides clear guidance for connecting parties

The draft FOS would extend the 144MW generator event limit to apply to network and load events. In light of elevated interest by data centres and hydrogen electrolysers to connect to the grid in Tasmania, the extension of the limit would provide connecting parties with transparency to design their plant accordingly.

Guidelines developed by AEMO and TNSPs could improve transparency on the hosting capacity of the mainland

The Panel sees merit in AEMO and TNSPs developing clear guidelines to provide transparency on the hosting capacity on the mainland grid. Such guidelines would clarify the hosting capacity of the network and would set clear expectations for market participants on the design attributes that need to be taken into consideration.

The draft FOS would retain the reporting obligations on accumulated time error

In response to stakeholder feedback, the Panel determined that the FOS should retain an obligation on AEMO to report and monitor on time error accumulation as a frequency performance metric. By maintaining the obligation in the FOS, stakeholders should expect the same level of transparency to which they have been accustomed.

2.3.7 Settings in the FOS should reflect consumer preferences and benefit consumers

Regulatory arrangements should take into account **consumer preferences**. As such, the Panel has considered the costs and benefits to consumers and the impacts on the consumer experience and delivery of power system services.

The settings in the draft FOS specifies the safe and secure range for operation of the power system. This aligns with the consumer preference for the system to be operated in a safe and secure manner while minimising the associated costs due to constraints on dispatch and enablement of ancillary services. This is demonstrated through:

- The proposed settings for RoCoF limits following credible and non-credible contingency events — which are based respectively on the technical capability of the existing generation fleet and emergency frequency control schemes.
- The extension of the limit on the maximum credible contingency size in Tasmania — which is based on the technical hosting capacity of the Tasmanian power system.
- The determination not to include a limit on the maximum allowable contingency limit in the mainland NEM, as such a limit would unnecessarily restrictive, given the alternative options for managing the associated risks of large connection application in the Mainland.
- The confirmation of the narrow setting for the PFCB to support the tight control of frequency around 50Hz — this would deliver benefits to consumers through increased system resilience while reducing the overall costs of frequency control as compared to wider settings of the PFCB under the current regulatory framework.
- The abolition of the requirement for AEMO to maintain time error within a set range, which would allow for changes to AEMO's operational practises to optimise the procurement and use of regulation services.

3 SETTINGS FOR CONTINGENCY EVENTS

BOX 3: KEY POINTS IN THIS SECTION

Requirements for the rate of change of frequency following contingency events

- Currently, the FOS does not include any arrangements relating to rate of change of frequency (RoCoF).
- The Panel's draft determination is to include limits in the FOS for RoCoF following contingency events. This would reflect changing operational conditions with the expected retirement of synchronous generation and associated reduction in inertia that would occur as a result of that, which currently acts to restrain RoCoF following contingency events.
- These new elements of the FOS will contribute to power system security by requiring AEMO to operate the system within the capabilities of existing generation plant and control schemes (EFCS/UFLS).
- They would also promote the efficient investment in, and operation of, energy resources by supporting the valuation and procurement of essential system services to manage post-contingency RoCoF such as:
  - the implementation of market ancillary service arrangements for fast frequency response services, which commence in the NEM on 9 October 2023.
  - the potential development of complementary arrangements to procure RoCoF control services from synchronous and synthetic inertia.
- The RoCoF requirements for Tasmania differ from the mainland due to the specific operational characteristics in the Tasmanian system. This reflects the higher RoCoF ride-through capabilities of the local generation fleet and the settings implemented by TasNetworks for existing dynamic control schemes used to manage non-credible contingency events
- The inclusion of limits in the FOS for RoCoF provide transparency on this important system metric and will help support secure and efficient operational outcomes into the future.

The draft FOS includes new provisions that would require that:

> Following a *credible contingency event,* the **rate of change of frequency** must not be greater than:
>
> - Mainland: 0.5Hz measured over any 500ms (1Hz/s)
> - Tasmania: 0.75Hz measured over any 250ms (3Hz/s)
>
> Following a *non-credible contingency* event or **multiple contingency event** that is not a *protected event*, AEMO should use reasonable endeavours to maintain the **rate of change of frequency** within:

- Mainland: 0.9Hz measured over any 300ms (3Hz/s)
- Tasmania: 0.9Hz measured over any 300ms (3Hz/s).

Maximum contingency size for Tasmania

- **The draft FOS** extends the 144MW generation event limit to apply to load and network events in Tasmania. This limit is necessary to address specific challenges in managing the island's power system and provide transparency to connecting parties, such as proposed hydrogen electrolysers and data centres, as to the hosting capacity of the grid.

Maximum contingency size for the mainland

- The Panel has decided that a limit in the FOS on the maximum contingency size for the mainland is not justified at this time as existing arrangements under the NER are sufficient to maintain the risks associated with increasing contingencies and more flexible mechanisms exist by which transparency can be improved in the mainland NEM.

System restoration

- **The draft FOS** renames the term "supply scarcity" as "system restoration". This revision would better reflect operational conditions for which this element of the FOS was intended to apply.

The changing nature of operational risks that must be managed to maintain the system in a secure operating state is an important consideration as the power system transforms. AEMO identified a number of gaps in the *Engineering framework* for potential actions to meet the needs of the power system over the next ten years.[33]

Some of the gaps identified by AEMO recognise the increasing risks to system security of large credible and non-credible contingency events. For example the disconnection of distributed PV, the risks associated with the disconnection of large loads and the risk of damage to critical network transmission equipment include those connecting renewable energy zones (REZs). AEMO found that there may be misalignment between existing frameworks in the NER and that the FOS that may need to be adjusted in light of new operational circumstances to allow AEMO to operate the network with greater flexibility.[34]

The settings in the draft FOS for contingency events are intended to provide a clear foundation for the operational performance requirements and limits in the power system in the context of the expected accelerated decarbonisation of the NEM as outlined in AEMO's ISP.[35]

Introducing a RoCoF standard would help reflect operational performance requirements. Sections 5 and 6 of the Issues paper also provide further explanation of a standard for rate of change of frequency (RoCoF) and the settings for contingency events.

33 AEMO, Engineering framework - Initial Roadmap, December 2021, p.26-47

34 Ibid, p.26-27.

35 AEMO, 2022 Integrated System Plan, June 2022, p.19.

In determining these revised arrangements, the Panel has aimed to:

- manage the trade-off between **economic efficiencies** and ensuring that the **power system remains within its secure** technical operating envelope while taking into account the particularities of the mainland and Tasmanian grids
- help guide the **cost-effective** procurement of ancillary services while ensuring that **system security is maintained**
- act as a guide to connecting parties by maintaining a **transparent**, **predictable** and **simple** indication of the hosting capacity of the grid
- align with **consumer preferences** for the system to be operated in a safe and secure manner while minimising costs over the long run.

This section includes:

- Section 3.1 — Requirements to maintain rate of change of frequency within acceptable ranges following contingency events
- Section 3.2 — A limit on the size of credible contingency events in Tasmania
- Section 3.3 — No limit on the size of credible contingency events in the mainland
- Section 3.4 — Application of the FOS during system restoration.

3.1 Requirements to maintain rate of change of frequency within acceptable ranges following contingency events

The draft FOS includes new requirements for how AEMO manages the rate of change of frequency following credible and non-credible contingency events. These new elements of the FOS define the safe operating envelope for the power system in the context of the ongoing reduction in system inertia due to the progressive retirement of synchronous thermal generators.

In the short term, the specification of limits for RoCoF would support the implementation of the new market ancillary service arrangements for fast frequency response services (very fast raise and very fast lower services). Over the longer term, these limits would also support the development of future arrangements to provide RoCoF control services including through synchronous and synthetic inertia. As such, this change to the FOS would assist with the valuation and procurement of essential system services to manage post-contingency RoCoF, thereby supporting efficient investment in, and operation of, energy resources.

The following sections set out how:

- the RoCoF limits would help to define the secure operating envelope for the power system
- the RoCoF limits would support the valuation and provision of RoCoF control services.

3.1.1 RoCoF limits would help to define the secure operating envelope for the power system

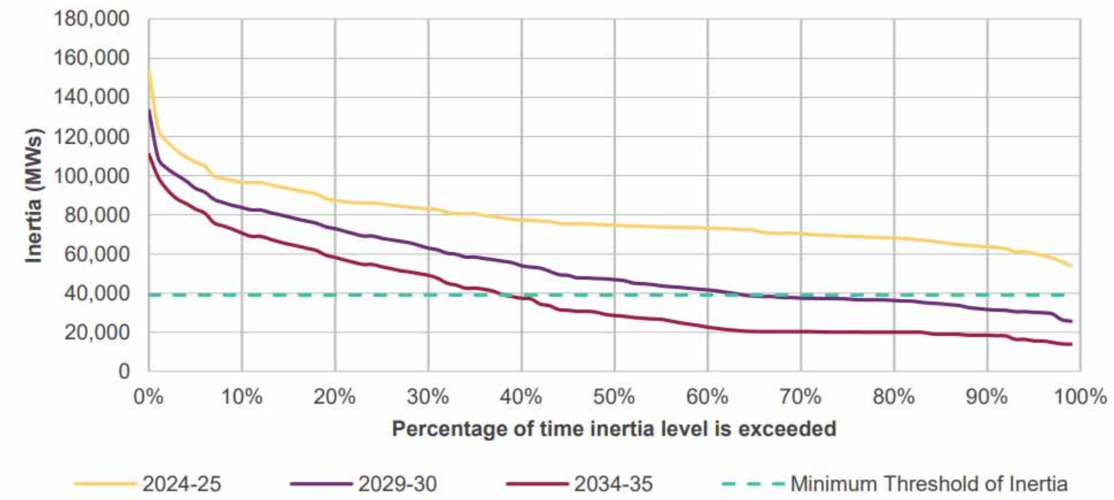
The limits in the draft FOS for RoCoF following credible and non-credible contingency events specify the range of RoCoF that aligns with secure operation of the power system. This element of the standard is expected to be increasingly important as the power system transitions and levels of synchronous inertia decline.

As the prevalence of synchronous machines in the power system decreases, the level of synchronous inertia in the power system is expected to reduce which, in the absence of market reforms or operational interventions, is expected to lead to an increase in RoCoF following contingency events. Power system inertia acts to limit the rate of change of power system frequency following a sudden change in the balance of generation and load on the power system, as is caused by contingency events.

AEMO project the progressive decline of power system inertia

As illustrated in Figure 3.1 below, AEMO predicts that inertia in the power system will progressively decrease such that, in the absence of interventions, the 99% availability of inertia will fall below the minimum threshold level for the mainland regions by 2029-30.[36]

Figure 3.1: NEM mainland inertia outlook



Source: AEMO, 2022 Integrated system plan - Appendix 7. Power system security, June 2022, p.33.

As system inertia decreases, there is an expectation that post-contingency RoCoF would proportionally increase which would likely test existing operational practises and plant capabilities. Under current market and regulatory arrangements AEMO could meet a RoCoF standard in a number of ways, including; inertia planning arrangements, limiting contingency size, and through the application of constraints on dispatch. In the future additional operational solutions may become available to AEMO, such as those being considered through the *Operational security mechanism* and *Efficient provision of inertia* rule changes.[37]

GHD's review of international approaches identifies potential value in specifying system limits

36 AEMO, 2022 Integrated system plan - Appendix 7. Power system security, June 2022, p.33. This minimum threshold for inertia is determined to be the sum of the regional thresholds for inertia (excluding Tasmania)

37 Refer to relevant project pages on the AEMC website.

for RoCoF

The results from GHD's survey of international power systems that was undertaken for the Reliability Panel shows that while only the Western Australian South West Interconnected System (SWIS) has implemented a formal operational standard for RoCoF, system operators are increasingly recognising the importance of RoCoF as part of the repertoire of power system security metrics and limits. Responses to the GHD survey confirmed that:[38]

> Many system operators surveyed consider the need to limit RoCoF to achieve power system security.

The RoCoF limits in the draft FOS reflect the technical capability of power system plant

The draft FOS includes limits for RoCoF in the mainland and Tasmania following credible and non-credible contingency events. These additional settings would reflect:

- that the RoCoF requirements following credible events align with the RoCoF ride-through capabilities of generation plant.
- The RoCoF requirements for non-credible contingencies relate to the technical capability of emergency frequency control schemes and under frequency load shedding (UFLS).

The consideration of these two factors is described further below.

The system RoCoF requirements for credible events align with the RoCoF ride-through capability for generation plant

The RoCoF limits in the draft FOS aligns with the expected RoCoF ride-through capabilities of the existing generation mix and is consistent with findings from GHD's survey of international approaches to RoCoF management.[39] The alignment is intended to minimise the risk of generators disconnecting from the grid following a contingency event. Generator RoCoF withstand is the capability of generation plant to ride-through different levels of RoCoF following contingency events. Where the RoCoF in the power system exceeds a generators ride through capability, it may disconnect following a power system disturbance, and have the consequence of making the disturbance worse, potentially leading to a cascading outage and at an extreme, a black system event.

The RoCoF limit set in the draft FOS also aligns with the existing requirements for connecting generators under the automatic and minimum access standards to demonstrate the capability of withstanding a RoCoF of ±4Hz/s and ±2Hz/s respectively, measured over 250ms.[40] By including a further standard in the FOS, the Panel intends to provide clear guidance to market participants and equipment manufacturers of the operational conditions they are likely to face allowing them to ensure that their equipment is capable of riding-through any expected system disturbances.

38 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.30

39 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, pp.30-31

40 Clause S5.2.5.2 of the NER

The RoCoF safe limit in the Western Australian wholesale electricity market (WEM) FOS

The GHD survey of international approaches to managing RoCoF found that:[41]

> Western Australia is the only surveyed jurisdiction with a legislated operational RoCoF limit. Presently, the safe RoCoF limit is considered to be 0.25Hz/s measured over 500ms. This may be gradually increased via a rule change if AEMO is satisfies that higher levels of RoCoF can be managed. This assessment would need to consider both generator ride through capability and the ability of emergency control schemes to accommodate a higher RoCoF.
>
> Some context surrounds this number. The WEM is currently in a transition period and plans to introduce fully co-optimised security constrained economic dispatch (SCED). This is tentatively scheduled for late 2023. Some rules are already in place and others will come into force later. As an example, a revision of the FOS was completed in February 2022 and this includes the RoCoF Safe Limit discussed above. This will set service quantities for a RoCoF Control Service (RCS) market but this does not yet exist.

As noted above, the initial WA RoCoF safe limit was introduced as part of the *Future power system* workstream for the WA Energy transformation strategy.[42] GHD's report identifies that the initial setting for the RoCoF safe limit in the WEM is driven by a concern that legacy generation may not be able to ride through RoCoF levels in excess of 0.5Hz/s.[43]

> To date, AEMO has not identified units in the SWIS that tripped as a result of a high RoCoF. However, the largest RoCoF event experienced in the SWIS was 0.44Hz/s. There is a risk that legacy generators may trip in the 0.5-1.0Hz/s range. Participants generally do not know the capability of their plant and OEMs may not be able to assist with determining the maximum RoCoF capability.

GHD's multi-jurisdictional RoCoF survey similarly concluded that:[44]

> Specifying a safe RoCoF limit in the NEM FOS in a similar manner to the WEM FOS may assist in maintaining system security and provide better guidance for market participants regarding the RoCoF they should experience

AEMO's advice includes an assessment of the RoCoF ride-through capabilities for the current generation fleet in the mainland and Tasmania. The key findings are:

- Certain types of synchronous plant are more likely to disconnect at high levels of RoCoF
- Inverter based generation (IBR) typically have higher RoCoF ride-through capabilities
- The Tasmanian hydroelectric dominated fleet can withstand a higher RoCoF

These points are described further below.

41 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.26
42 Energy Transformation Taskforce, Revising Frequency Operating Standards in the SWIS - Information Paper, November 2019, p10.
43 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.26
44 Ibid.

Certain types of synchronous plant are more likely to disconnect at high levels of RoCoF

Despite considerable efforts, there remains uncertainty surrounding the RoCoF withstand capabilities of different types of synchronous plant. AEMO's assessment is that synchronous units can generally can be anticipated to successfully ride-through disturbances up to 1Hz/s (with some exceptions), but many demonstrate a range of issues for disturbances around 2Hz/s. [45]

AEMO notes that the vulnerability of synchronous plant depends on several factors, including:[46]

- The nature of the unit as high inertia, gas-fired units tend to be more vulnerable to high RoCoF.
- Where the unit is connected as units in more electrically remote locations may more vulnerable to high RoCoF.
- How the unit is operating, as modelling suggests that units operating at higher set points or when operating with an under-excited power factor have lower RoCoF ride-through capabilities.
- Ambient conditions, as gas turbines are more vulnerable to high RoCoF in extreme conditions.
- The nature of the voltage, as RoCoF ride-through capability is diminished where there are additional voltage issues.

Analysis of international jurisdictions by GHD has revealed that RoCoF withstand capability concerns are widespread, including in the different operational circumstances. Most respondents to GHD's survey raised similar unease about the uncertainty surrounding the vulnerability of existing operators to ride-through high levels of RoCoF:[47]

> Apart from EirGrid, most survey respondents identified concerns regarding whether legacy generators could be relied upon to comply with the RoCoF ride-through requirements expressed in grid codes.

EirGrid (the Irish system operator) addressed similar concerns by testing and validating the legacy generation fleet's RoCoF ride-through capability through the DS3 Programme.[48] The GHD survey stated that:

> EirGrid [through the DS3 Programme] has gained sufficient confidence that the existing generating fleet should be able to ride through a 1Hz/s RoCoF event and is therefore planning to relax the operational RoCoF target from 0.5Hz/s to 1Hz/s measured across 500ms.

45 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.24.

46 Ibid.

47 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.29

48 See: https://www.eirgridgroup.com/how-the-grid-works/ds3-programme/

Inverter based generation (IBR) typically have higher RoCoF ride-through capabilities

It is generally understood that IBR are better able to ride through high RoCoF events as power electronic based inverters are less vulnerable to changes in frequency when compared to electro-mechanically linked synchronous units.

AEMO confirmed this understanding as long as protections schemes operate as intended, the advice concluded:[49]

> [IBR] generally can be expected to ride-through high RoCoF (up to 3-4Hz/s), as long as there is no specific RoCoF-based protection applied, or misoperation of protection schemes.

As the NEM continues on the current decarbonisation trajectory it is expected that there will be a gradual reduction in the number of synchronous generators. Once the most vulnerable units have retired, it may be in the long term interests of consumers for the Panel to recalibrate the RoCoF standard for credible contingency events and reassess the trade-off between system security and the costs of ancillary services ultimately borne by market consumers. The relevance of this for a future review of the FOS is described in section 1.3.3.

The Tasmanian hydroelectric dominated fleet can withstand a higher RoCoF

The Tasmanian power system differs from the mainland in that it is currently a hydroelectric dominated (synchronous) grid with a very high penetration of IBR (both wind generation and the Basslink interconnector).[50] Frequency control is greatly affected by status of Basslink which can contribute a high proportion of the Tasmanian load or generation mix.[51] As such, the FOS includes a number of different settings for the Tasmanian system given the specific characteristics of securely operating the island network.

Hydro-electric generators, despite being synchronous, are capable of withstanding much larger RoCoF when compared to thermal generators. AEMO's advice states that:

> Tasmania is predominantly Hydro powered [and] hydro units in Tasmania can withstand high RoCoF, at least up to ±3Hz/s.

It is also expected that given the relative size of the network in comparison to the mainland, the system experiences higher RoCoF following credible contingency events and during normal operation. This is confirmed by the output of the GHD survey:[52]

> Smaller power systems have experienced the highest RoCoF.

As such, the Panel determined that a wider RoCoF standard for Tasmania, of 0.75Hz over any 250ms (3Hz/s) for credible contingency events. This setting for Tasmania aligns with the current operating practise and would be in best interests of consumers as it would:

49 Ibid.

50 Submission to the issues paper: TasNetworks, p.5.

51 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.43.

52 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.27

- promote system security by aligning the standard with the capabilities of the regional generation mix
- promote the efficient operation of the power system by reducing the amount of ancillary services that must be procured.

The RoCoF limits for credible contingencies are tailored to the capabilities on the mainland and Tasmania

The draft FOS introduces new RoCoF standards for credible contingencies in both the mainland and Tasmania, tailoring the requirements to the particularities of the mainland and Tasmanian networks. The specification of the limits, including the measurement timeframes, are intended to reflect the inherent inertial response of the power system to a significant contingency event. The draft FOS requires AEMO to ensure that:

> Following a *credible contingency event,* the **rate of change of frequency** must not be greater than:
>
> - Mainland: 0.5Hz measured over any 500ms (1Hz/s)
> - Tasmania: 0.75Hz measured over any 250ms (3Hz/s)

The Panel notes that these RoCoF standards would codify the existing operational arrangements applied by AEMO to manage high RoCoF following credible contingency events on the mainland and Tasmania. The Panel does not consider that the introduction of these standards will lead to significant changes to the way interconnected system security is currently managed in the near term. However, in the longer term it is expected that AEMO may need to take action to deliver sufficient inertia — or equivalent RoCoF control services — to meet the standard. Initially, the RoCoF standard would be expected to bind for operation of the Tasmanian region and for SA during islanded operation. Under current market and regulatory arrangements, AEMO can meet a RoCoF standard in a number of ways, including through inertia planning arrangements, limiting contingency size, and through the application of constraints on dispatch. The Panel notes that the AEMC will further consider the arrangements for the provision of RoCoF control services through the pending *Efficient provision of inertia* rule change request.

Most stakeholders agreed that a RoCoF standard would need to consider the RoCoF withstand capability of the existing fleet

Most submissions to the Issues paper supported the introduction of RoCoF standards and suggested the Panel consider the RoCoF ride-through capabilities of legacy generators when in determining system standards for RoCoF following contingency events.[53] Origin Energy also suggested the Panel consider the interaction of a RoCoF standard with the RoCoF withstand capabilities mandated as part of the connections process.[54]

The Panel has into account stakeholder submissions and aligned the RoCoF standard for credible contingency events in the mainland with the expected performance of the existing

53 Submissions to the Issues paper: AEC, p.4; Delta Electricity, p.10; EnergyAustralia, p.3; TasNetworks, p.4; Shell Energy, p.4.

54 Origin Energy, Submission to the review of the frequency operating standard issues paper, 29 June 2022, p.2.

synchronous generator fleet to manage the likelihood that high RoCoF levels could lead to cascading outages across the network. Importantly, the Panel has introduced higher limit for Tasmania to reflect the greater RoCoF withstand capabilities of hydroelectric generators and minimise the cost of procuring ancillary services. This reflects the Panel's role in managing the trade-off between system security and economic efficiency in the long-term interests of consumers.

The RoCoF requirements for non-credible contingencies relate to the technical capability of emergency frequency control schemes

Under frequency load shedding (UFLS) is an emergency frequency control mechanism intended to manage the effect of non-credible contingency events that overwhelm the containment ability of contingency FCAS. UFLS involves the automatic disconnection of load to rebalance the network and avoid a cascading generator outage.

As part of this analysis the Panel has considered:

- that UFLS is the last wall of defence against a collapse in system frequency
- the fact that dynamic UFLS approaches are already implemented in Tasmania
- the introduction of appropriate RoCoF limits for non-credible contingency and protected events.

Each of these points is described further below.

UFLS is the last wall of defence against a collapse in system frequency

UFLS is a crucial component of frequency control frameworks by being a cost-effective insurance mechanism against a cascading outage following a significant contingency event. The satisfactory performance of UFLS schemes can be degraded if system RoCoF is high enough to overwhelm the relay's reaction times. AEMO's advice illustrates how, at high RoCoF levels, frequency can fall so rapidly that it reaches minimum thresholds before UFLS can property react and deactivate load:[55]

> In the 2016 South Australia Black System Event, RoCoF was so fast (in excess of -6Hz/s[56]) that system frequency collapsed while the region's UFLS relays were still in their pickup time.

As part of its advice to the Panel, AEMO modelled the frequency outcomes in a South Australian island following a non-credible separation event (double circuit trip of the Heywood Interconnector) co-incident with a trip of a large IBR generating units of various sizes to induce various levels of RoCoF after separation.

AEMO's acceptance criteria at different levels of RoCoF required the following frequency outcomes:[57]

55 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.28.

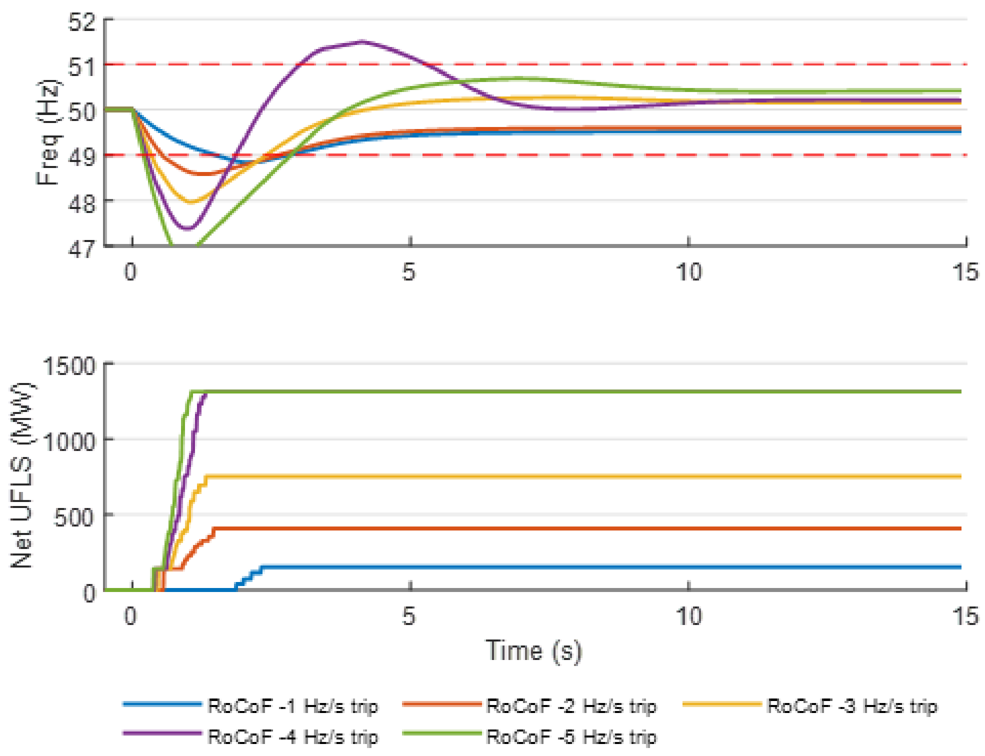
56 AEMO, *Black system South Australia,* September 2016, Figure 6.

57 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.30

1. The Frequency nadir is contained above 47.6Hz to allow for a safety market above the 47Hz limit specified in the FOS, and to avoid tripping the most sensitive UFLS loads.
2. No frequency overshoot is observed once UFLS has been activated.
3. The UFLS load tripped does not significantly exceed the initial contingency size.

Figure 3.2 shows that the cases with RoCoF exceeding 3Hz/s both fail the acceptance criteria. In both cases, AEMO's advice considers it likely that it would lead to a cascading outage. At 3Hz/s frequency is successfully arrested just before 48Hz and the level of load shedding only marginally exceeds the assumed contingency size.

Figure 3.2: Outcomes at different RoCoF levels



Source: AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.32.
Note: To induce different levels of RoCoF the model assumed contingency sizes of: 235MW, 475MW, 705MW, 940MW and 1,185MW for 1Hz/s, 2Hz/s, 3Hz/s, 4Hz/s and 5Hz/s respectively.

The summary of AEMO's findings suggest that UFLS schemes generally:[58]

- appear to operate correctly at RoCoF of 1Hz/s or 2Hz/s
- show issues arising under some conditions at 3Hz/s
- should not be expected to operate successfully at 4Hz/s or 5Hz/s.

58 Ibid., p.40.

The Panel determined that the satisfactory performance of UFLS should guide the settings of RoCoF limits in the FOS for non-credible or multiple contingency events to minimise the risk of a cascading outage and a black system event.

Dynamic UFLS approaches are already implemented in Tasmania

As discussed earlier, the Panel understands that the Tasmanian power system differs from the mainland in many aspects. Due to those complexities, TasNetworks has already implemented various RoCoF controls that are particularly well suited to the needs of the regional network. The Panel would not want to override those chosen settings.

The TasNetworks RoCoF limits currently in place aim to maintain system security following credible and known high-impact non-credible events. These tailored UFLS settings attempt to avoid unnecessary load shedding of customers for credible events such as the loss of Basslink, and to manage the risk of a black system were specific known non-credible events to occur.[59]

The current settings in Tasmania are:[60]

1. If a RoCoF of greater than 0.75 Hz is detected within 250 ms (3Hz/s RoCoF): UFLS block 1 Relay will activate a measurement cycle at 49Hz.
2. Frequency change over time (df/dt) limit is defined as 0.4Hz over 340ms. If the frequency change exceeds this limit then the relay will trigger UFLS block 1. Block 1 will therefore trigger from 48.6Hz.
3. Block 2 operates in the same way, though if the conditions of item 1) are met, the block 2 relay will activate a measurement cycle at 48.8Hz, triggering block 2 UFLS from 48.4Hz.
4. If item 1) criteria is not met, that is, if RoCoF is not measured at 0.75Hz over 250ms (3Hz/s), then UFLS block 1 will trigger at 48Hz.

The Panel's determination would align the RoCoF standard for non-credible contingency events with the existing dynamic UFLS introduced by TasNetworks.

Appropriate RoCoF limits for non-credible contingency and protected events

The draft FOS includes new RoCoF standards for non-credible contingency events or multiple contingency events in both the mainland and Tasmania. The Panel has amended the draft FOS to include the following obligation:

> Following a *non-credible contingency* event or **multiple contingency event** that is not a *protected event*, AEMO should use reasonable endeavours to maintain the **rate of change of frequency** within:
>
> - Mainland: 0.9Hz measured over any 300ms (3Hz/s)
> - Tasmania: 0.9Hz measured over any 300ms (3Hz/s).

59 Ibid., pp.44-45.

60 Ibid.

The Panel decided against an explicit RoCoF limit in the FOS for protected events as matters relating to AEMO's operation of the power system can be considered, on a case-by-case basis, when initially declaring the event.[61] Such an outcome was supported by CS Energy in its submission to the issues paper:[62]

> There should not be a standard for protected events for the same rationale as to why protected events are not currently specified in the FOS but rather the FOS is applied to the protected event. It is anticipated that AEMO will consider RoCoF limits when defining the operational conditions of a protected event.

As for the existing requirements in the FOS for multiple contingency events, the RoCoF limit for a non-credible or a multiple contingency event is a 'reasonable endeavours' requirement. As noted by the Panel in its 2017 final determination, this 'reasonable endeavours' requirement reflects the impracticality of maintaining the power system RoCoF within the prescribed limits following the occurrence of all possible multiple contingency events.[63]This 'reasonable endeavours' obligation sets out the performance objective for the management of multiple contingency events; i.e. to the extent that it is reasonably possible for AEMO to do so, AEMO should limit post non-credible contingency RoCoF to within the limits set out in the draft FOS. The Panel considers that the inclusion of a 'reasonable endeavours' obligation sets a clear performance target to guide preparations for non-credible contingencies and multiple contingency events, including the design and operation of EFCS and UFLS by AEMO and TNSP's in accordance with NER Cl 4.2.6(c).

Stakeholders raised the interaction between a RoCoF standard and UFLS in submissions to the issues paper

Several submissions to the issues paper raised the importance of the interaction between RoCoF standards and the effective operation of emergency frequency control schemes.[64] Several stakeholders also recommended the inclusion of different RoCoF standards to be in force under different operating conditions.[65]

The Panel, aligning with stakeholder feedback, has determined that the draft FOS should include RoCoF standards for both credible and non-credible contingency events. The draft FOS requires that AEMO use reasonable endeavours to maintain the system within the RoCoF limit following non-credible contingency events. This approach would be consistent with the current FOS settings that recognise that it is not possible to plan for and manage all potential non-credible events.

61 Clause 8.8.4(f)(3) of the NER

62 CS Energy, Submission: Review of the Frequency Operating Standard - Issues paper, 9 June 2022, p.8.

63 Reliability Panel, Review of the frequency operating standard - stage one, final determination, 14 November 2017, p.31.

64 Submissions to the Issues paper: AEC, p.4; Energex, p.1; TasNetworks, p.4; Shell Energy, p.4.

65 Submissions to the Issues paper: EnergyAustralia, p.3; TasNetworks, p.4; CS Energy, p.8 ; Shell Energy, p.4.

3.1.2 RoCoF limits would support the valuation and provision of RoCoF control services

The introduction of a RoCoF standard in the FOS would promote efficient investment in and operation of energy resources by supporting the valuation and procurement of essential system services to manage post-contingency RoCoF such as:

- The implementation of new market ancillary service arrangements for fast frequency response (very fast raise and very fast lower services).
- The potential development of arrangements to procure RoCoF control services such as synchronous and synthetic inertia.

Each of these points is described further below.

The implementation of market ancillary services for fast frequency response

Due to the increased post-contingent RoCoF when operating the power system at low levels of inertia, faster acting frequency control services are required to arrest and stabilise the system frequency within the existing system FOS settings.

In July 2021, the AEMC made the *Fast frequency response market ancillary service rule 2021* to introduce the two new FCAS services into the NEM. The new FFR services will respond more quickly to power system disturbances to help maintain system security during periods of lower inertia operation. The markets for the new FFR services are scheduled to commence on 9 October 2023.

Although FFR might enable operation at lower levels of system inertia, it cannot replace the immediacy of an inertial response when arresting a fall in frequency. But the Panel's introduction of a post-contingency RoCoF standard will help assist in the specification and dispatch of FFR services. The limit will support the system studies required to determine the speed of response for the new FFR services along with the required quantity to be procured.

The value of a RoCoF standard in guiding the specification and procurement of FFR was identified by stakeholders in submissions to the Issues paper.[66] The AEC in particular noted that:[67]

> The AEC agrees with the Panel that it would be a valuable objective for tuning the future very fast FCAS and inertia markets.

Potential future arrangements for the valuation and provision of RoCoF control services

Implementing a RoCoF standard as part of the FOS would also inform the consideration future arrangements to support the provision of RoCoF control services. Such arrangements are currently being considered by the AEMC through the following open and pending rule change requests:

- Through the *Operational security mechanism* rule change, the Commission is considering a new mechanism for the procurement and scheduling of system security services and

66 Submissions to the Issues paper: EnergyAustralia, p.3; TasNetworks, p.4; CS Energy, p.8.

67 AEC, Submission to Review of the frequency operating standard - Issues paper, 9 June 2022, p.4.

configurations to support the secure operation of the power system.[68] This includes the development of new arrangements to price, procure and schedule resources that deliver security services through secure system configurations. The proposed RoCoF standard could inform AEMO on the secure level of system inertia, which would guide the procurement of security services.[69]

- Through the *Efficient provision of inertia* rule change, in which the AEC proposes the development of new market ancillary service arrangements for inertia.[70] While the AEMC has not yet commenced consultation on this rule change request, it is understood that it provides a vehicle to investigate and develop enduring arrangements for the provision of RoCoF control services to meet the future needs of the power system. A standard for RoCoF in the FOS could provide guidance on the level of inertia AEMO required to maintain system security, which would be an important input to the development of enduring arrangements for the provision of RoCoF control services.

3.2 A limit on the size of credible contingency events in Tasmania

The draft FOS confirms the existing 144MW limit on the maximum allowable generation event in Tasmania and extends the limit to also cover load and network events. AEMO's advice informed the Panel's draft determination that:

- the contingency size limit for Tasmania supports system security - discussed further in section 3.2.1
- the contingency size limit in Tasmania sets clear expectations for new connections - discussed further in section 3.2.2.

3.2.1 The contingency size limit for Tasmania supports system security

The Panel's draft determination extends the existing limit for the largest allowable generation event for the Tasmanian region in the FOS to:

- clarify the allowable technical operating envelope for the Tasmanian power system with respect to the credible loss posed by the loss a generating system
- promote system security while allowing for the implementation of generator contingency schemes (GCS) to enable partially or completely unconstrained operation
- confirm the 144MW limit (and not to increase the limit to 155MW).

Each of these points are described further below.

The credible contingency limit accounts for operational limitations of the Tasmanian grid

The limit on the size of the largest generation event in the Tasmania power system was included by the Panel following the 2008 review of the FOS for Tasmania. Supported by advice from AEMO, this element of the draft FOS reflects the particular challenges associated

68 See: https://www.aemc.gov.au/rule-changes/operational-security-mechanism

69 AEMC, Operational security mechanism, Draft Determination, 21 September 2022.

70 See: https://www.aemc.gov.au/rule-changes/efficient-provision-inertia

with operating the Tasmanian power system including its relative small size and the scarcity of fast-acting contingency reserves.[71]

In 2019, the Panel reaffirmed the limit and revised the drafting to clarify where the limit is to be measured, that the limit applies in absence of network outages and that the arrangements allow for the limit to be met in relation to one or more generating systems with a combined capacity in excess of 144MW.[72]

AEMO's advice to the Panel recommended that the existing 144MW limit on generation events for Tasmania be maintained and that the limit be extended to also apply to single network and load events. AEMO concluded that:[73]

> Increasing or removing the limit would expose Tasmania to operational risks that cannot be adequately managed at this time.

Moreover, AEMO confirmed that load tripping and generator raise ancillary services are limited in Tasmania and that a single generator contingency cannot securely exceed the volume of available load tripping or FCAS.

The Panel concluded that the existing generator event limit of 144MW remains in the best long term interests of consumers by mitigating operational security risks in the context of the small size of the Tasmanian system and the relative scarcity of fast acting contingency reserves in Tasmania.

Generator contingency schemes enable unconstrained generation above the limit

A generator can mitigate the effective size of a generation event relating to its generating system through the procurement of contracted load shedding to account for the disconnection of the generator. These generator contingency schemes (GCS) are already in effect for the Tamar Valley Power station and the Musselroe Wind Farm and restrict the effective contingency size to the 144MW limit.[74] [75]

In support of the current limit, TasNetworks noted the existence of the GCDs which enable affected generators to operate entirely or partially unconstrained if the contracted load shedding is operational. TasNetworks explained that:[76]

> It can be noted that a second GCS has recently been commissioned, allowing all generators, that would otherwise be impacted by this limit, to operate unconstrained when sufficient load tripping services are available. The existence of a practical solution that facilitates unconstrained operation while also addressing the operability of the power system, supports the merits of capping contingency sizes.

71 AEMO, Advice for Reliability Panel's Review of Frequency Operating Standard, 8 December 2022, pp.50-51

72 Reliability Panel, Review of the Frequency Operating Standard - Stage two, Final Determination, 18 April 2019, p.12

73 AEMO, Advice for Reliability Panel's Review of Frequency Operating Standard, 8 December 2022, p.50

74 AEMO, Advice for Reliability Panel's Review of Frequency Operating Standard, 8 December 2022, p.43

75 Submission to the issues paper: TasNetworks, p.5; Woolnorth Renewables, p.1.

76 TasNetworks, Submission to the Issues paper, 6 June 2022, p.5.

The Panel concluded that the existence and availability of contingency schemes are sufficient to adequately mitigate the economic effects of maintaining the current generation event limit. The Panel acknowledges that generators entering into GCS do incur costs and may still be constrained, but that these are necessary when considering the security of the overall Tasmanian network.

The draft FOS maintains the limit at 144MW

The Panel considered whether it would be viable to increase the limit on the size of the largest credible contingency event in Tasmania, as proposed by Woolnorth Renewables, and notes the reasoning provided in its submission to the issues paper. Raising the current limit from 144MW to 155MW would allow for the Musselroe windfarm — owned by Woolnorth Renewables — to operate unconstrained at all times, as was the case during the period July 2013 to January 2020.[77] The Panel understands that a new generator contingency scheme commenced operation in Tasmania in December 2021, allowing Musselroe windfarm to operate without constraint when sufficient load tripping services are available.[78]

The Panel considers that there are several uncertainties associated with raising the limit on a generation event in Tasmania from 144MW to 155MW. For example, it could:

- have material impacts in terms of changes to the quantities of FCAS to be procured by AEMO
- introduce operational risks as it is possible that the additional volumes of FCAS may be difficult to procure in the Tasmanian region
- introduce financial burdens, as it is unclear what the cost impacts may be if AEMO were required to procure further FCAS reserves.[79] [80]

Noting the AEMO advice and the TasNetworks submission, the Panel considers that the size of the limit in the FOS for the largest generation event in the Tasmanian system should be maintained at 144MW.

The Panel has extended the limit to apply to load and network events in light of the unprecedented interest by energy-heavy industries to connect to the network

Both AEMO and TasNetworks support the Panel extending the generator size limit to apply to load and network events. TasNetworks noted in its submission that:[81]

> TasNetworks is presently seeing unprecedented interest related to the connection of large scale data centres and hydrogen electrolysers, both of which have the potential to increase the maximum contingency size above existing levels unless clear directions is provided through the FOS.

77 Woolnorth renewables, Submission to the Issues paper, 6 June 2022, p.5.

78 TasNetworks, Submission to the Issues paper, 6 June 2022, p.5.

79 Reliability Panel, Review of the Frequency Operating Standard – Stage two, Final Determination, 18 April 2019

80 As part of the 2019 FOS review, the Panel undertook a detailed analysis of the incremental costs and benefits from Musselroe Wind Farm operating unconstrained above 152.6MW. The analysis indicated that where generation exceeds 152.6MW, one additional MW of generation output from the wind farm drives approximately one additional MW of requirement for R6 FCAS service.

81 TasNetworks, Submission to the Issues paper, 6 June 2022, p.5.

The justification for extending the limit to apply to load and network events mirrors the reason for the generator event limit. The availability (and cost) of fast lower FCAS and the increasing levels of inertia required to minimise the increase in post-contingency RoCoF are both particularly hard to come by in Tasmania. As such, the Panel concluded that a broader limit would lead to an improvement in system security outcomes in the region as supported in the AEMO advice:[82]

> AEMO has observed situations in Tasmania where there are restrictions on the ability to provide fast lower FCAS. Future load sizes greater than the present resources can manage would create operational risks that may not be able to be managed prior to the contingency event.

Importantly, the Panel does not consider that expanding the limit would have a cooling effect on investment decisions in Tasmania. Large loads would continue to be able to connect to the network by designing their plant or network to comply with the limits specified in the FOS, as confirmed in the AEMO advice:[83]

> [The contingency size limit] will not, of course, limit or prevent load intensive industries from connecting large plants in Tasmania. The plant design may need to account for separate circuits within the plant to avoid a single point of failure greater than 144MW from both a load or network perspective.

Stakeholders had diverse views on the contingency size limit in Tasmania

In submissions to the issues paper, stakeholders explained a variety of views. TasNetworks strongly supports maintaining and expanding the current limit of 144MW. Woolnorth Renewables, the owner of Musselroe Wind Farm, supported an increase of the limit to 155MW as it would enable the unconstrained operation of the generating system, and:[84]

> WNR calculated the annual loss in revenue, as a result of this limit, is over $1.0M.

Woolnorth submission drew the Panel's attention to the reduction in cost and increase in the availability of 6 second FCAS raise services in recent years. Woolnorth contends that the increase is many times greater than what would be required if the limit were increased to 155MW. Moreover, Woolnorth concludes that the generation event limit is likely to impact on other future energy development of state significance.

The Panel notes the concerns voiced by a number of stakeholders in response to the issues paper. In particular, the Panel recognises that the retention of this element of the FOS is likely to have an adverse impact on the operation of Musselroe Wind Farm. However, as discussed in the previous review of the FOS, in coming to its determination the Panel has considered the following:[85]

82 AEMO, Advice for Reliability Panel's Review of Frequency Operating Standard, 8 December 2022, p.51

83 Ibid.

84 Woolnorth Renewables, Submission to the Issues Paper, 9 June 2022, p.2.

85 Reliability Panel, Review of the Frequency Operating Standard – Stage two, Final Determination, 18 April 2019

- the Panel does not have the power under the NEL or the NER to grant exemptions or derogations for any market participant in its determination of the FOS
- the security implications for the Tasmanian power system
- the net economic costs and benefits to Tasmanian electricity consumers.

3.2.2 The contingency size limit in Tasmania sets clear expectations for new connections

By including a limit in the FOS, the Panel intends to send transparent signals to generators and loads of the hosting capacity of the relatively small Tasmania grid and the scarce availability of ancillary services. By setting clear expectations for connecting generators and loads, the Panel intends to provide transparent guidance on the technical hosting capacity for the Tasmanian grid and thereby reduce the likelihood of unexpected outcomes and delays during the connection process.

As explained in section 3.2.1, the Panel considers it unlikely that the limit would stop the development of large renewable energy parks nor energy-intensive industries. Instead, it would clearly set out the connection and design requirements expected to ensure that system security is not jeopardised.

3.3 No limit on the size of credible contingency events in the mainland

Given the changing nature of the risks in the power system, as captured by AEMO's *Engineering framework*, the Panel has investigated the expected costs and benefits of introducing a maximum contingency size limit for the mainland.

The Panel concluded that, despite the uncertainties and risks identified by AEMO from expected future power system developments, there is not sufficient justification to introduce a generation event limit in the FOS for the mainland NEM at the current time, as:

- current security arrangements under the NER are sufficient to manage operational security on the mainland, and
- the introduction of a firm limit in the FOS would be inflexible and could dissuade investors from developing large projects, thereby potentially compromising economic efficiencies.

3.3.1 Current arrangements under the NER are sufficient to maintain security in the mainland

The Panel has concluded that existing arrangements under the NER are sufficient to maintain system security on the mainland and that it is unlikely that a generator event limit would lead to a material improvement. The Panel determined that:

- the existing automatic and minimum access standards are sufficient to ensure that system security is not compromised
- the scale of the mainland power system and the increased volume of FCAS available diminish the vulnerability of the system to contingency events.

The existing connections process takes into account risks to system security

Clause S5.2.5 of the NER sets out the connection requirements under the automatic and minimum access standards that must be considered by TNSPs. In the NEM, generators are expected to meet the automatic access standards, including those which specify that a generating system must have plant capabilities and control systems that are sufficient so that they do not result in a reduction in inter-regional or intra-regional power transfer capability.[86]

At the very least, under the minimum access standards, the plant must ensure that there is no reduction in the ability to supply customer load due to a reduction in power transfer capability.[87] This process, negotiated with TNSPs, already disincentivises the connection of units that could cause larger credible contingencies as it could affect the ability to supply existing customers.

Importantly, the existing process considers factors other than frequency, such as voltage and power transfer capability, to fully determine the hosting capacity of the network at a specific location.

GHD's survey found that it is unusual for a jurisdiction to formally adopt a largest credible contingency size limit in their security standards as the risk is usually managed through the connections process. GHD found that:[88]

> Aside from Great Britain, no jurisdictions formally specify a largest contingency limit in their security standards.

Most jurisdictions that participated in the survey have developed mechanisms through the connections process to minimise the risk of large units attempting to connect to the grid. GHD concluded that:[89]

> Survey feedback suggests that it may not be appropriate to expand the NEM FOS to include a limit on the largest contingency size as the economic and security trade-offs are potentially better managed through other grid connection processes.

The greater scale and availability of FCAS allows for a more flexible approach

The scale, generation mix and availability of affordable FCAS on the mainland distinguishes the system from the Tasmanian grid. The Panel considers that the mainland network is much more capable of leveraging market mechanisms to manage operational risks from large credible contingency events due to a relative abundance of fast-acting FCAS when compared to Tasmania.

AEMO's advice to the Panel confirmed the considerable complexities involved in managing the Tasmanian grid, as:[90]

> The Tasmanian power system differs from the mainland in many aspects with its own complexities. This often results in separate, independent FOS requirements applicable to Tasmania's unique scenario.

86 Clause S5.2.5.12(a) of the NER.
87 Clause S5.2.5.12(b) of the NER.
88 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.32
89 Ibid.
90 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.43.

> Raise and lower FCAS availability is scarce. Often in high wind periods, hydro plants are run on minimum generation and are unable to lower.

As such, the Panel resolved, despite confirming the Tasmanian maximum generation event limit, to not include a firm limit in the FOS as it is not justifiable given that it is unlikely to lead to a material improvement in security outcomes.

Stakeholders did not consider that a mainland limit on maximum contingency size would be an effective way to manage system security

Several stakeholder submissions expressed scepticism that a contingency size limit in the FOS would result in material improvements to system security that cannot be accomplished through existing mechanisms.[91] Moreover, several submissions noted that the Panel would also need to consider the risks associated with disconnection of distributed energy resources (DER).[92]

The Panel agrees with stakeholders that setting a maximum contingency size limit for the mainland would not be in the best long-term interests of consumers. As such, the Panel has determined to not include such a limit in the draft FOS, as existing mechanisms in the NEM sufficient to manage the risk of increasing contingency sizes at this time.

3.3.2 A limit on contingency sizes for the mainland would be inflexible

The Panel determined not to include a generation event limit for the mainland NEM in the draft FOS as such an approach would be an inflexible way to account for system needs. A firm generation event limit would not:

- account for the other limiting factors that need to be considered as part of the connections process
- adequately consider for regionally specific network characteristics
- be able to be updated sufficiently frequently to recognise changes in the operating envelope of the network.

Frequency is rarely the sole factor in the connections process on the mainland

AEMO's advice confirmed that the characteristics of the mainland grid, with its greater geographical size with a wider diversity of generation resources, means that the limiting factor when connecting generators is not always frequency related. In its advice to the Panel, AEMO noted that:

> Limiting factors were not always frequency related. Localised sub-regional restrictions were often limited by voltage related matters and there were also thermal limitations in many areas, which should be dealt with using constraints on the dispatch of the plant.

As such, the Panel considers that introducing a firm limit in the FOS would give connecting generators a false sense of confidence that their proposed arrangements would be sufficient

91 Submission to the issues paper: Delta Electricity, p.15; Shell Energy, p.5.

92 Submission to the issues paper: Delta Electricity, p.15; CS Energy, p.9.

to fulfil the connection requirements under the NER. The connection process that requires a myriad of other factors to be taken into consideration, is outside the remit of the Panel.

A contingency size limit would need to reflect regional characteristics

The Panel is aware that a single contingency size limit for the mainland may not adequately represent regional characteristics and hosting capacities. Instead, the Panel would be required to determine regional or sub-regional limits in order to provide investors with clarity on the design or size of generators that the system is capable of hosting.

In its advice, AEMO explained that any contingency size limit due to network hosting capacity would be regionally specific:[93]

> A value for SA would not be the same as QLD. Connection size limit [would] also be needed sub-regionally.

As such, the Panel determined that a generator event limit in the FOS would not serve the interests of market participants. Instead, the existing negotiation process under the rules is more capable of reflecting regional particularities.

A limit in the FOS would not be sufficiently flexible to reflect network upgrades

In order to reflect this rapidly evolving transmission and distribution networks, the Panel would be required to continuously review any contingency limits for the mainland. The Panel does not consider that the FOS would be reviewed frequently enough to adequately update contingency size limits to reflect changes to the hosting capacity of the network.

As part of its advice, AEMO noted:[94]

> Contingency limits are not only set based on generators but also on other aspects including network equipment, and these contingency limits can change as the system changes.

The Panel determined that NSPs are better positioned to flexibly adjust network hosting capacities as the system evolves as they are responsible for maintaining and upgrading network equipment. Moreover, NSPs have the resources and understanding of their systems to establish network capabilities properly and regularly.

AEMO and TNSPs are best placed to manage the risk of large contingencies

These findings show that it would be difficult for a specification in the FOS to adequately reflect the geographical differences and evolving technical capabilities of network equipment in different regions on the mainland at present time, or in the future.

As such, it is the Panel's determination that it is more appropriate for TNSPs and AEMO to coordinate the connection of and manage the operational risks posed by large generators and loads on a case-by-case basis. Maintaining the current approach provides market

93 Ibid.

94 Ibid.

participants with greater flexibility when compared to a rigid limit in the FOS, that could remain in force for a considerable amount of time.

These findings align with the conclusion from the AEMO advice that states:[95]

> AEMO's view is that it may be more appropriate for operational issues related to the connection of large generators and loads [on the mainland] to be managed by AEMO and TNSPs directly.

The Panel does consider that it could be in the interests of consumers for the Commission to consider implementing an explicit co-optimisation of marginal FCAS costs and increasing contingency sizes, as done in the Wholesale Electricity Market (WEM) in Western Australia. By dynamically allocating the costs of ancillary services to facilities generating higher quantities and those with a poor reliability history, NEMDE would automatically allocate costs to those most suitable to bear them thereby resulting in an optimal outcome for consumers.

The outcome of GHD's survey found that such an optimisation process naturally disincentivises generators from a connection that would increase the size of the largest credible contingency as:[96]

> … the optimisation performed by the market dispatch engine may choose to constrain a larger generator if that results in the least cost dispatch outcome considering the co-optimised energy and essential system service markets.

Stakeholders warned that an unjustified contingency size limit in the mainland could have a significant impact on investment decisions

In submissions to the issues paper, stakeholders suggested that a limit on maximum contingency size in the mainland would constrain the economic operation of the system, without clear benefits to system security. Moreover, Delta Electricity, Origin and Iberdrola noted that such a blunt instrument would have serious implications for the viability of new projects.[97] Moreover, Delta Electricity and CS Energy stated that such a limit would have to take into consideration the effect of DER, including rooftop solar interruptions.[98]

Iberdrola raised the possibility that, if the cost of managing contingencies becomes prohibitive, the AEMC should consider alternative causer-pays mechanisms for FCAS such as runway pricing to allocate costs more efficiently as contingency risks increase.[99]

The Panel's determination to not include a maximum contingency size limit for the mainland reflects the concerns expressed by stakeholder in submissions to the issues paper. The Panel does not consider that there is sufficient justification to introduce a blunt and inflexible limit as it is unlikely to result in improvements in system security nor accurately reflect the safe operating envelope of the power system. TNSPs and AEMO remain the most knowledgeable

95 Ibid.

96 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.32

97 Submissions to the issues paper: Delta Electricity, p.15; Origin Energy, p.2; Iberdrola, p.6.

98 Submissions to the issues paper: Delta Electricity, p.15; CS Energy, p.9.

99 Submission to the issues paper: Iberdrola, p.6.

of the capabilities of their network, as such, they should retain the responsibility of managing operational risks related to large contingency sizes.

3.3.3 Guidelines explaining the hosting capacity of the mainland NEM could increase transparency

If a limit were introduced in the FOS, the Panel would provide a clear and transparent investment signal to market participants on what the hosting capability of the network is. In its advice AEMO agreed, noting:[100]

> A transparent MW credible contingency size limit for the mainland would be of value to guide new project sizing, particularly in the connections process.

The Panel agrees that increased transparency and commentary to provide clear expectations to connecting parties could be of value. However, as explained above, there is not sufficient value, a great deal of complexity and a lack of flexibility in setting a limit for the mainland.

Moreover, as noted in AEMO's advice, the limiting factor is often not frequency related. As such, a limit in the FOS may provide connecting parties with a false sense of confidence that the barriers to connecting to the grid have been alleviated.

The Panel considers that a similar level of transparency could be attained through the development of guidelines by AEMO and mainland TNSPs. The guidelines, updated more periodically than the FOS, would provide investors and market participants with clear expectations on the hosting capacity of the network, taking into account network considerations other than frequency. This would allow connecting generators to design their plant to adhere to these requirements to conceivably simplify the connections process.

Stakeholders raised that introducing a limit could provide greater clarity

In submissions to the issues paper, the AEC raised that introducing a contingency size limit for the mainland would provide clarity to investors on what the secure operating envelope of the network is.[101] Potential energy developers would be able to consult the FOS contingency size limit and plan their investments accordingly.

The Panel does not consider that the transparency benefits are sufficient to outweigh the probable economic inefficiencies that would follow the introduction of a maximum contingency size limit for the mainland. Safe system hosting capacity guidelines, developed by AEMO and TNSPs, could provide similar transparency benefits for stakeholders and would be able to take into account the totality of limiting factors in the connections process, in addition to frequency.

3.4 The FOS for system restoration

The settings for supply scarcity were introduced, as part of the 2009 review of the FOS, to define the range of allowable frequency for the power system while load is being restored

100 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.44.

101 AEC, Submission to the review of the frequency operating standard - issues paper, 9 June 2022, p.4.

following a major power system incident on the mainland.[102] When originally introducing the settings for supply scarcity, the Panel considered the trade-off between benefits for consumers and the potential for any increased system security and reliability risks.

The Panel's assessment of the FOS that applies during supply scarcity was triggered by concerns raised by stakeholders that queried the appropriateness of the current settings in the FOS that apply for the purpose of load restoration at times of supply scarcity.[103] A reformatting of the FOS performed during the previous review has introduced more strenuous requirements for generators under the automatic and minimum access standards for responding to frequency disturbances.[104] Under the NER connections process, generators are required to be capable of operating continuously within the range of the operational frequency tolerance band (OFTB) for supply scarcity, 48 - 52Hz, for at least the stabilisation time of 10 minutes.

As part of this draft determination, the Panel has renamed "supply scarcity" to "system restoration" to clarify the purpose of the wider settings in the FOS. The updated language better reflects the aims of the initial settings to support the timely restoration of load following a large non-credible contingency event.

Importantly, the Panel is retaining the associated requirements placed on generators as part of the automatic and minimum access standards to show the capability to operate continuously during the system restoration process. It is likely that during restoration following a black system event, the power system would be prone to further disturbance and potential collapse, as such, it is crucial that AEMO has the confidence that plant would remain online despite the possibility of more volatile frequency.

In determining these revised arrangements, the Panel has aimed to:

- improve the **secure** and **reliable** operation of the power system, in line with **consumer preferences**, by enabling an accelerated reconnection of load following a non-credible contingency event
- provide AEMO with a greater range of **flexibility** when restoring the power system following major power system incidents while **minimising costs** over the longer term.

This section includes the Panel's consideration of the renaming of "supply scarcity" in the FOS, including:

- Section 3.4.1 - Interaction with the automatic and minimum access standards
- Section 3.4.2 - The renaming of this element of the FOS better aligns with the expected operational conditions.

3.4.1 Interaction with the automatic and minimum access standards

In the current FOS, the term "Supply scarcity" refers to a mode of operation where, following a contingency event, the frequency has reached the applicable recovery band and AEMO

102 Reliability Panel, Application of Frequency Operating Standards During Periods of Supply Scarcity, Final Determination, April 2009, p.1

103 Shell Energy, Submission to the frequency operating standard - issues paper, 9 June 2024, p.4.

104 Clause S5.2.5.3 of the NER

considers the power system is sufficiently secure to begin the re-connection of load. Under this mode of operation, frequency performance requirements are relaxed to enable AEMO to prioritise the re-connection of load over tight frequency control.

Prior to this review, the Panel was made aware of an interaction arising between the FOS and requirements in the NER for Generating system response to frequency disturbances.

As a result of formatting changes made to the FOS through the 2019 review, a connecting generator must demonstrate the capability for continuous uninterrupted operation within the range 48 - 52 Hz for 10 minutes to achieve the automatic access standard, because:[105]

- 48 - 52 Hz is the widest setting in the FOS for the operational frequency tolerance band.[106]
- 10 minutes is the "recovery time" within which the frequency must be returned to the normal operating frequency band.

The Panel understands that prior to the 2019 review, connecting generators were required to show continuous operation at a narrower range of 49-51 Hz.

3.4.2 The renaming of this element of the FOS better aligns with the expected operational conditions

The Panel determined to retain the existing settings of the OFTB in the FOS, but rename "supply scarcity" to "system restoration" to better reflect the purpose of the wider bands and minimise confusion.

The use of the phrase "supply scarcity" appears to be a misnomer which has a different meaning in general language when compared to the definition in the FOS. It has led to an understandable misinterpretation of the band's purpose and a reasonable questioning of why a generator would need to show the capability of uninterrupted operation at 52 Hz if supply of electricity is "scarce".

AEMO's advice to the Panel corroborated this view and confirmed their understanding of the purpose of the wider settings, stating that:[107]

> The technical requirements for the 'supply scarcity' frequency band are sound and required. That is, during load restoration following a contingency event, meaning:
>
> 1. A significant contingency event has occurred. FOS applied to the event, applicable for the event.
> 2. There was considerable load shedding as a result of the contingency event.
> 3. The event has passed and AEMO is restoring the power system so load can be re-connected and the 'supply scarcity' FOS applies from this point, until the system is restored.

105 Clause S5.2.5.3(b) of the NER.

106 This range applies during supply scarcity in the mainland NEM.

107 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, pp.49-50.

AEMO advised that the settings in the FOS that apply for "supply scarcity" be maintained, but that this element of the FOS be renamed to "system restoration", to avoid confusion as to the expected operational conditions for which this part of the standard applies.[108] Essentially, the supply scarcity frequency bands apply during the restoration of the system. During the restoration, a contingency event can occur, hence, a wider band is required to enable an accelerated re-connection of load.

As such, the Panel has made a draft determination to rename the existing settings for "supply scarcity" to "system restoration". Importantly, the draft FOS makes no change to the OFTB settings that set the required frequency outcomes following a credible contingency event and relate to the generator access standards under NER cl.S5.2.5.2. . The Panel considers that the existing settings are in the best interests of consumers by enabling an accelerated re-connection of load when restoring the system following a non-credible contingency event.

Wider system restoration settings allow for an accelerated re-connection of load following a large contingency event

The Panel introduced the settings for supply scarcity as part of the 2009 review of the FOS as it determined that the introduction of wider settings was in the best interests of consumers by accelerating the re-connection of load following significant contingency events. The final determination concluded that:[109]

> The Panel considers that relaxing the FCAS requirements during a load restoration period will make more generator capacity available to supply customers. This is expected to allow NEMMCO to restore supply at a faster rate, thus reducing the impact on customers following a significant multiple contingency event.[110]

As part of the current review, the Panel reexamined the settings and concluded that the wider OFTB is still in the best interests of consumers as it would enable the length of any disruption to energy supply to be minimised for end-use consumers. The more comprehensive generator withstand capabilities, confirmed during the connections process, would allow AEMO to confidently tolerate more volatile frequency without needing to acquire further contingency FCAS reserves as it initiates a system restart.

Stakeholders supported the Panel's assessment of the OFTB setting for periods of supply scarcity

Submissions to the issues paper noted the purpose of the settings for supply scarcity, and supported the Panel's assessment of the OFTB applied during those times.[111] In its submission, Shell Energy acknowledged that any changes would need to take into consideration the effect on consumers were load reconnected more gradually following a black system event.[112]

108 Ibid.

109 Reliability Panel, Application of Frequency Operating Standards During Periods of Supply Scarcity, Final Determination, April 2009, p.13

110 From 1 July 2009 NEMMCO ceased operations with the roles and responsibilities transferred to AEMO

111 Submissions to the issues paper: Delta Electricity, p.13; Shell Energy, p.4;

112 Shell Energy, Submission to the review of the frequency operating standard - issues paper, 9 June 2022, p.4.

The Panel's assessment of the settings for supply scarcity has taken into consideration the costs incurred by consumers were the reconnection of electricity supply following a major contingency event delayed. AEMO's advice confirmed that the more strenuous OFTB settings are crucial in providing the control room with greater confidence that units will be capable of operating at the wider frequency range without disconnecting.

4 FREQUENCY PERFORMANCE DURING NORMAL OPERATION

BOX 4: KEY POINTS IN THIS SECTION

- The Panel's draft determination for this element of the FOS has been informed by technical advice from AEMO as well as independent advice and analysis undertaken by GHD advisory.
- Modelling undertaken by GHD demonstrates net economic benefits for electricity consumers by maintaining a narrow setting for the PFCB — such that frequency is tightly controlled around 50Hz. The benefits of controlling frequency tightly around 50Hz include increased power system resilience and reduced aggregate costs for frequency control.
- The settings would **promote power system security and resilience**, by:
  - effectively controlling power system frequency to 50Hz
  - reduce the risk and volume of load shedding following non-credible contingency events
  - increase the likelihood of rapid re-synchronisation of islanded regions following separation events
  - support stable operation through distributed control that is immune to mal-operation of centralised control and communication systems (AGC - SCADA).
- The settings would support the **efficient investment in**, and **operation of** the power system by reducing the overall work done (and the associated costs) to control power system frequency during normal operation.
- The Panel considers that it will be appropriate for this element of the FOS to be revisited at a later date, following a suitable period of operational experience with the new Frequency performance payments arrangements in place. Given that these incentive arrangements are due to take effect on 8 June 2025, the Panel considers that a subsequent review of the FOS could commence in the first half of 2027.

The draft FOS includes the following additional requirements for the mainland and Tasmania:

- Confirmation that the target frequency for the mainland and Tasmania is 50Hz.
- Confirmation of the primary frequency control band (PFCB) as 49.985 - 50.015Hz. (Consistent with the initial setting in the NER)

The draft FOS maintains the following existing requirements for the mainland and Tasmania:

- The normal operating frequency band (NOFB) remains as 49.85 - 50.15Hz.
- The normal operating frequency excursion band (NOFEB) as 49.75 - 50.25Hz.

> Except as a result of a *contingency event* (which may be a **generation event**, a **load event** or a **network event**), **system frequency**:
>
> a) must be maintained within the applicable normal operating frequency excursion band, and
>
> b) must not be outside of the applicable normal operating frequency band for
>
> more than 5 minutes on any occasion and not for more than 1% of the time over any 30-day period.

The settings in the FOS for normal operation establish the required frequency outcomes for the power system in the absence of contingency events. The energy market dispatches generation to match expected demand every five minutes. However, even in the absence of contingency events, variations in supply and demand within each dispatch interval can lead to a power imbalance that results in frequency moving away from the nominal target of 50Hz. The control of frequency during these operating conditions is achieved through a combination of automatic primary frequency response (PFR) from individual generators and regulation services controlled through AEMO's automatic generation control (AGC) system.[113]

Importantly, the settings in the FOS that apply during normal operation also impact on the system outcomes following contingency events. For example, when the frequency is closer to 50Hz before a contingency event, then a wider buffer is established before frequency exceeds the technical limits of power system plant, which could lead to cascading failure and a black system event.

However, there are costs associated with the enablement and provision of system services used to control frequency to 50Hz. These costs relate to the enablement and utilisation of regulation services and the delivery of PFR. PFR may be delivered as a consequence of the mandatory PFR arrangements that apply for scheduled and semi-scheduled generators or due to voluntary provision beyond the mandatory requirements.

The Panel notes that the AEMC has recently concluded a package of reforms to the NER related to the provision of PFR in the national electricity system. The AEMC's final rule, *Primary frequency response incentive arrangements*, confirmed that scheduled and semi-scheduled generators are obligated to provide PFR to help control power system frequency and support the resilience of the power system to contingency events.[114] It also introduces new incentive arrangements, through frequency performance payments, that will value helpful frequency response provided in accordance with the mandatory arrangements. The Commission envisages that the frequency performance payments will also encourage

113 Further information on the fundamentals of power system frequency control is available in Appendix B of the Consultation Paper for this Review, available on the project webpage.

114 AEMC, Primary frequency response incentive arrangements - Final Determination, 8 September 2022.

voluntary action from generators and loads that will help control frequency into the future. The new frequency performance payments arrangements will commence on 8 June 2025.

Consistent with stakeholder responses to the issues paper, the key focus of the Panel's consideration for this element of the FOS has been the analysis of the costs and benefits associated with different settings for the PFCB that directly relates to the expected range of power system frequency during normal operation. The Panel's draft determination is informed by advice from AEMO and detailed power system modelling undertaken by GHD to study the operational and economic impacts associated with varying the PFCB.

The draft FOS confirms the existing settings for the NOFB and NOFEB that specify the allowable range for frequency during normal operation. It also clarifies that the target frequency for the power system is 50Hz, which aligns with the fundamental frequency control objective for the power system. Supported by expert advice from AEMO and independent analysis provided by GHD, the draft FOS maintains the PFCB as 49.985 – 50.015 Hz, which is consistent with the initial setting for this band in the NER. The GHD analysis shows that the PFCB is the primary driver for how tightly frequency is controlled to 50Hz. This work also demonstrates that narrower settings for the PFCB deliver improved system resilience to non-credible contingency events and lower aggregate costs for frequency control, when compared with wider settings for the PFCB.

This draft determination is made in the context of the current market and regulatory arrangements. The Reliability panel recognise there is a necessity for narrow band PFR to control frequency close to 50Hz. Under the current arrangements, there is a reliance on Mandatory PFR to deliver this narrow band control. Frequency performance payment arrangements which commence from 8 June 2025 are expected to provide an incentive for the provision of narrow band PFR, beyond and in addition to the mandatory requirement.

As discussed in section 1.3.3, the Panel considers that the settings in the FOS that apply during normal operation, and the PFCB, should be revisited following a suitable period of operational experience with the new Frequency performance payments arrangements in effect. The Panel recommends that this future review commences in the first half of 2027, allowing a period of almost 2 years to monitor the impacts of the frequency performance payments arrangements and inform further consideration of the PFCB and the settings in the FOS for normal operation.

The remainder of this chapter is structured as follows.

- Section 4.1 - sets out the Panel's considerations in relation to the target and allowable range for frequency during normal operation as well as a summary of stakeholder views on this aspect of the FOS.
- Section 4.2 - sets out the Panel's considerations in relation to the PFCB.

4.1 The target and allowable range for frequency during normal operation

The draft FOS maintains the following existing requirements that set the allowable range for frequency during normal operation in the mainland and Tasmania:

- The normal operating frequency band (NOFB) remains as 49.85 – 50.15Hz.
- The normal operating frequency excursion band (NOFEB) as 49.75 – 50.25Hz.

In addition to maintaining these elements of the FOS, the draft FOS also includes a new requirement that the target frequency for the mainland and Tasmania is 50 Hz. This aligns with the one of the fundamental principles for operation of the power system, that the target frequency is 50Hz, and reflects the objective of AEMO's Automatic generation control (AGC) system that provides central control of frequency regulation services.[115]

The following section summarises stakeholder views in relation to the settings in the FOS for normal operation and the Panel's related draft determination.

4.1.1 Stakeholder views on the settings in the FOS for normal operation

Most stakeholders welcomed the Panel's review of the settings in the FOS for normal operation and the PFCB and generally accepted that frequency performance in the NEM has improved significantly following the introduction of mandatory narrow band PFR and the initial narrow setting in the NER for the PFCB of 49.985 – 50.015Hz.[116]

Some stakeholders consider that the operational outcomes associated with the current settings should be maintained, i.e. that the operational and resilience benefits justify frequency being controlled as close as is reasonably practical around 50Hz.[117] Energy Australia noted that the current frequency performance in the NEM — relative to the NOFB — implied that the current setting for the PFCB may be too narrow and/or that the current setting for the NOFB may be too wide.[118]

The issues paper sought stakeholder feedback on potential approaches to reflecting a target for a narrower frequency distribution in the FOS, consistent with the observed frequency distribution in the NEM prior to 2015 and following the re-introduction of narrow band PFR in 2020.[119] However, stakeholders expressed reservation with respect to these proposals, noting that the focus of the Panel's assessment should be on investigating the costs and benefits of controlling frequency closer to or further away from 50Hz. Stakeholders highlighted the importance that the Panel's determination should aim to balance the benefits of tight frequency control with the costs of achieving this outcome and that the Panel's consideration of the PFCB and NOFB be supported by independent economic analysis.[120]

For example the AEC noted that:[121]

> it is incumbent on those who prefer tighter frequency performance to identify and quantify exactly what system security benefits result from tighter standards such that

115 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.22.

116 For example, Submissions to the Issues paper: AEC, p.1; Energy Australia, p.1-2; TasNetworks, p.3.

117 For example, TasNetworks submission to the Issues paper, p.3.

118 Energy Australia, submission to the Issues paper, pp.1-2.

119 Issues paper, pp.23-26.

120 For example, submissions to the Issues paper: AEC, pp.2-3; Delta Electricity, p.2; EnergyAustralia pp.2-3; SnowyHydro, p.1; CS Energy, pp.2-7, Shell Energy, p.3; Iberdrola, pp.2-3; Origin Energy, pp.1-2.

121 AEC, Submission to the Issues paper, p.2.

> the Panel can compare them to their costs of delivery.

Similarly, in relation to the NOFB, Energy Australia noted:[122]

> exact values to be determined via rigorous, independent economic assessment. This should include consideration of:
>
> - the trade-offs and synergies possible under various wider PFR settings,
> - the technical and commercial realities of both current and future generation mixes, and
> - customer insights on acceptable frequency performance.
>
> Lacking such analysis, it is unclear how the optimal balance between security, financial, efficiency and operational concerns can be achieved. Nor how the long-term interests of customers can be maximised per the National Electricity Objective (NEO).

The Panel agrees that economic analysis on the costs and benefits of controlling frequency closer or further away from 50Hz is an important input into its assessment of the NOFB. As such the Panel's draft determination for the settings in the FOS during normal operation is supported by power system modelling and estimated economic impacts of varying the PFCB between 5mHz and 500mHz. The results of this analysis are described in section 4.2.

4.1.2 The draft FOS maintains the current allowable frequency ranges during normal operation and confirms the target frequency as 50Hz.

AEMO's advice is that the settings in the FOS that specify the allowable range for frequency during normal operation should remain unchanged at this time, but that the FOS should include a clarification that the target frequency in the power system is 50Hz.[123]

In relation to the allowable range from frequency during normal operation, AEMO notes that:[124]

> - The NEM power system is in the early stages of a complete transformation of generation, transmission, distribution and consumer load technologies and operation. However, the physics, science and electrical engineering principles remain the same.
> - Frequency is a critical technical property for the stability of the power system. Frequency control principles have not changed.
> - Mandatory narrow band PFR enabled successful control of the NEM to be reinstated after a period of unacceptable poor control of frequency.
> - The NEM power system is now in a strong position to enable a transition to renewable energy sources with a firm basis of known frequency control practices.

122 Energy Australia, Submission to the Issues paper, pp.2-3.

123 AEMO, Advice for the Reliability Panel Review of Frequency Operating Standard, pp.21-22

124 Ibid.

- Given the extreme volume of work to be completed by the energy industry to facilitate the transformation, amending the normal operation parameters of the FOS are not a priority at this point in time and changes could present unknown risks.

In relation to the clarification of the target frequency as 50Hz, AEMO notes that:[125]

- All calculations for frequency management, protection schemes, deviations etc. require a specific number not a range. All existing calculations use 50Hz.
- It has always been accepted and understood that the NEM frequency target is 50Hz, though it has never been explicitly stated.

The Panel accepts AEMO's view that there is not a case for changing the requirements in the FOS that specify the allowable range for frequency during normal operation and that the current settings appear fit for purpose. The Panel also accepts that providing clarity in the FOS that the target frequency for the power system is 50Hz would align with existing operational and control objectives.

It is noted that there have been zero exceedances of the FOS for the mainland from Q4-2020 to Q3-2022.[126] While this outcome may be interpreted as a sign of over provision of the PFR service, the analysis undertaken by GHD demonstrates net benefits to consumers through controlling frequency close to 50Hz. Further consideration of the costs and benefits of controlling frequency close to 50Hz is set out in section 4.2.

4.2 The primary frequency control band — PFCB

The draft FOS sets the PFCB at 49.985 – 50.015Hz which is consistent with the initial setting for the PFCB in the NER. The confirmation of the PFCB at the current setting is supported by AEMO advice along with detailed independent analysis of the associated costs and benefits during normal operation and in the relation to power system resilience.

The remained of this section is structured as follows.

- Section 4.2.1 - describes how the PFCB drives the distribution of power system frequency
- Section 4.2.2 - sets out how a narrow setting for the PFCB delivers improved power system resilience
- Section 4.2.3 - sets out how a narrow setting for the PFCB delivers lower total costs for controlling power system frequency.

4.2.1 The PFCB drives the distribution of system frequency around 50Hz

Under the current market and regulatory arrangements in the NEM, the PFCB — through the mandatory PFR arrangements — drives the distribution of power system frequency. This means that a wider PFCB will result in a wider distribution of frequency around 50Hz and a

125 Ibid.

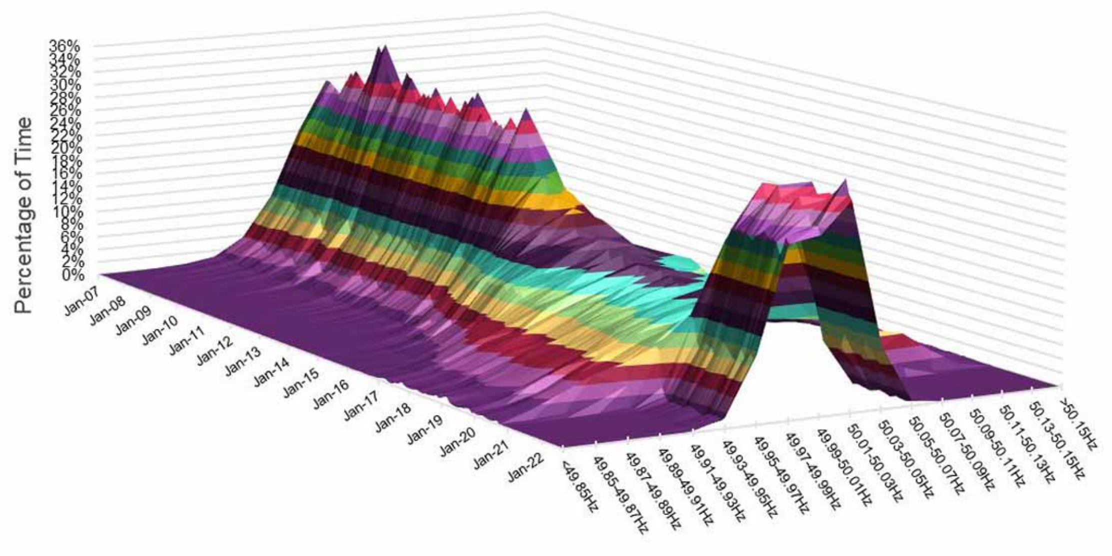
126 AEMO, Frequency and time error monitoring - Quarter 3 2022, p.10.

narrower PFCB will result in a narrower distribution of frequency. This relationship is driven by the current operational environment where scheduled and semi-scheduled generators have an operational frequency control requirement to provide PFR in accordance with the Primary Frequency Response Requirements (PFRR) specified by AEMO.[127]The PFCB sets a lower bound for the maximum allowable deadband that AEMO specifies for affected generators in its PFRR. The PFCB is defined in the NER as:[128]

> the range 49.985Hz to 50.015Hz, or other such range as determined by the Reliability Panel in the power system security standards.

The impact of the relationship between the PFCB and the distribution of frequency in the NEM is demonstrated in Figure 4.1. It is understood that prior to 2015 most generators in the NEM operated with zero range of insensitivity to changes in power system frequency. The degradation of the frequency distribution during the period 2015 – 2020 is understood to be due to a reduction in aggregate frequency responsiveness as a result of generators implementing changes to their controls systems to desensitise their active power response to deviations in power system frequency away from 50Hz. The implementation of mandatory PFR in 2020 lead to a restoration of tight frequency control from 2021 onwards. This restoration of tight frequency control around 50Hz was due to the coordinated reinstatement of narrow band PFR in 2020/21 which lead to a majority of the generation fleet narrowing their response "dead bands" to be close to the PFCB.[129]

Figure 4.1: Frequency distribution in the NEM — January 2007 to September 2022



Source: AEMO, Frequency and Time Error Monitoring – Quarter 3 2022, 11 November 2022, p.7.

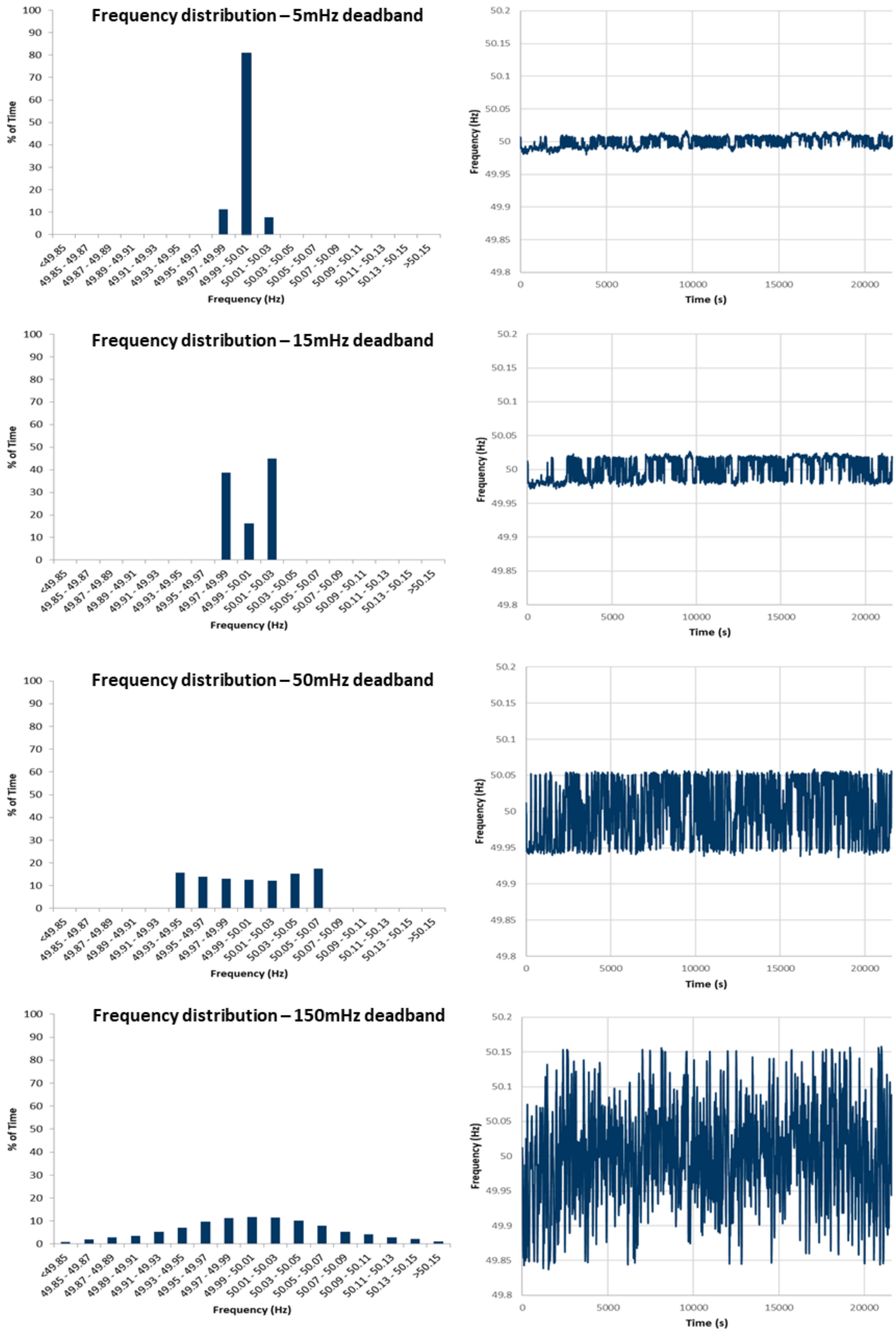
127 Clauses 4.4.2 and 4.4.2A of the NER.

128 Chapter 10 of the NER.

129 AEMO, Enduring PFR requirements for the NEM - White Paper, August 2021, p.3.

The relationship between the PFCB and the distribution of frequency is further demonstrated through the results of the GHD analysis. This analysis looked at a range of different operational scenarios in the present power system and for the projected generation fleet in 2033 under AEMO's ISP step change scenario. The analysis considered periods of high and low renewable dispatch along with periods of high and low forecast error. The results included in Figure 4.2, show a steady degradation in the quality of the frequency distribution as the generator frequency deadband is widened. This demonstrates that the PFCB — which aligns with generator control deadbands — sets the region of no control around 50Hz. As the PFCB is widened, so to is the region of no control.

Figure 4.2: GHD Modelling results — Frequency distribution due to variation of PFCB



Source: GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, pp.19-22

Note: Based on the modelled system behaviour for a 6-hour period in September 2021 with low variable renewable energy dispatch and low forecast error variability

The frequency performance payments arrangements that will commence on 8 June 2025 are intended to complement the existing operational PFR frequency control requirements. However, the degree to which the frequency performance payments will drive increased provision of PFR leading to increased levels of aggregate frequency responsiveness in the power system will not be known until a suitable period has passed to allow for monitoring of the impact of the new arrangements. Therefore, as discussed in section 1.3.3, the Panel considers that the settings in the FOS that apply during normal operation, and the PFCB, should be revisited following a suitable period of operational experience with the new frequency performance payments arrangements in effect.

4.2.2 A narrow setting for the PFCB delivers improved system resilience

The Panel's draft determination is supported by advice from AEMO and GHD that controlling frequency close to 50Hz delivers value to electricity consumers through increased power system resilience. AEMO's advice is that the existing settings for the PFCB and normal operation are necessary to maintain effective control of frequency that is fundamental to a secure and resilient power system. This value is demonstrated in the following ways:

- reduced risk and volume of load shedding due to less severe frequency nadirs following non-credible contingency events.
- increased likelihood of rapid resynchronisation of islanded regions following separation events. This acts to shorten the restoration time following separation events leading to reduced market and customer impacts, including load shedding and costs of regional energy and FCAS procurement.
- Local distributed PFR provides redundancy in the event of failure or mal-operation centralised control and communication systems (AGC – SCADA).

Narrow PFCB settings reduce the risk and volume of under-frequency load shedding

The analysis undertaken by GHD demonstrates how widening the PFCB is expected to result in increased shedding of customer load following significant non-credible contingency events.

The frequency control framework in the NEM is based on a multi-tiered approach where AEMO purchases contingency FCAS reserves to be able to control frequency and avoid load shedding for a credible contingency event, such as the loss of the largest single generation unit or transmission line. Non-credible contingency events that exceed the single largest credible event can and do occur on the power system and these events utilise under-frequency load-shedding (UFLS) as a fall-back measure to rapidly rebalance generation and consumption.[130]

130 Refer to Appendix C of the Issues paper for further detail on the NEM frequency control frameworks.

The GHD analysis modelled a range of different non-credible events in the NEM based on the 2022 generation fleet and the projected generation fleet in 2033 under the ISP step change scenario.[131] The non-credible events studied included:

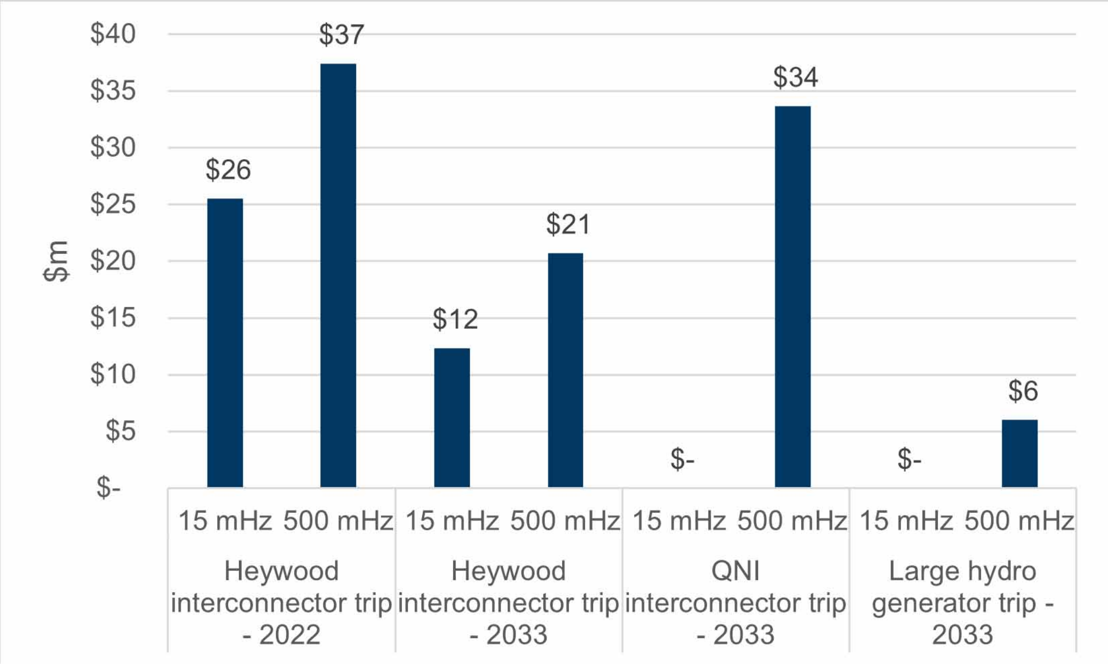
- Queensland separation with the loss of 1200 MW transfer from QLD to NSW on QNI.
- South Australia separation following the transfer of 650 MW from Vic to SA across the Heywood link.
- Simultaneous trip of a large level of generation — 2 x Loy Yang A units at full load (1130 MW).
- Trip of large NEM load — 600 MW of net load as per Western Downs – Columboola event.

GHD modelled the system outcomes for each of these non-credible contingency events to determine the power system frequency outcomes and the quantity of any lost customer load due to UFLS. Where the model predicted load shedding, the value of this lost load was derived using a VCR of $42.52 and an assumed outage duration of 1 hour.[132] The results of this modelling showed that wider PFCB settings lead to more extreme frequency outcomes and increased volumes of UFLS. The expected cost of this load shedding in 2022 dollars is shown in Figure 4.3.

131 GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.13

132 Ibid.

Figure 4.3: Estimated cost of load shedding due to different PFCB settings for key non-credible contingencies ($million in 2022)



Source: GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.46

Note: Valuation assumes outage duration of 1-hour and Value of customer reliability of $42.52/kWh.

The GHD modelling estimates the additional cost of load shedding at between $6 million and $34 million depending on the specific operational scenario. The Panel notes that the nature and incidence of non-credible contingency events is inherently uncertain. As such these results are not interpreted as a definitive measure of the benefit of narrow band PFR, rather they provide a sense of the scale of value to electricity consumers for narrow settings of the PFCB. GHD reiterates this in their report, while noting that the NEM typically experiences a major non-credible event of one kind or another on an annual basis:[133]

> The precise probability of a non-credible contingency resulting in load shedding is not directly quantifiable, and falls outside standard power system planning frameworks. Historical experience on the NEM suggests that non-credible contingencies may occur on an annual basis, but impacts can differ significantly depending on generation dispatch, load conditions and other factors.

The Panel notes the potential for future operational arrangements to be developed to further support system resilience following non-credible contingency events. An example of such an arrangement is proposed by Shell Energy in their submission to the Issues paper. Shell suggests that a new arrangement whereby scheduled load and/or wholesale demand

133 Ibid.

response providers could provide an emergency balancing service by providing load shedding within the current settings for automatic UFLS which commence below 49Hz.[134] The Panel recognises the potential value of such an arrangement and notes that this suggestion aligns with the UFLS remediation actions identified by AEMO in its 2022 Power system frequency risk review.[135] Through this work AEMO has identified a potential shortfall in the volume of load available in SA to provide UFLS, particularly during periods of high distributed PV generation. AEMO is currently working on remedial actions for this.[136]

> AEMO, SAPN and ElectraNet are collaborating to procure additional emergency under-frequency response. SAPN and AEMO are collaborating on the development of specifications for a new service to deliver emergency under-frequency response, which could be either a reduction in load, an increase in generation, or both. SAPN intends to seek expressions of interest from industry during 2022, for service implementation in late 2022.

In the context of the uncertainty and operational challenges inherent to the ongoing power system transformation, the Panel notes that narrow band PFR provides additional resilience to unpredictable high impact low probability events. This is shown in the GHD analysis to reduce the expected cost of UFLS following such events. While the total resilience benefits of tight frequency control around 50Hz are difficult to quantify, it is likely that they extend beyond those set out in the GHD analysis to include - for example - decreased risk of other severe outcomes following non-credible contingencies such as regional separation and, at the extreme, black system events.

Narrow PFCB settings increase the likelihood of rapid re-synchronisation following separation events

Tight control of frequency around 50Hz has been shown to deliver further resilience benefits through enabling the rapid re-synchronisation of islanded regions following non-credible separation events. This beneficial consequence of narrow band PFR is noted in AEMO's advice and supported by the results of power system modelling undertaken by GHD.

AEMO's advice notes that recent operational experience has shown that controlling frequency close to 50Hz delivers improved resilience to non-credible separation events.[137] Distributed narrow band PFR is shown to increase the likelihood of rapid synchronisation of the islanded regions, thereby speeding up system recovery and reducing the impact of the event on electricity customers. The separation of Queensland and New South Wales due to multiple generation contingencies on 25 May 2021 provides an example of frequency outcomes following such an event. The frequency trace for NSW and QLD during this event is shown in Figure 4.4.

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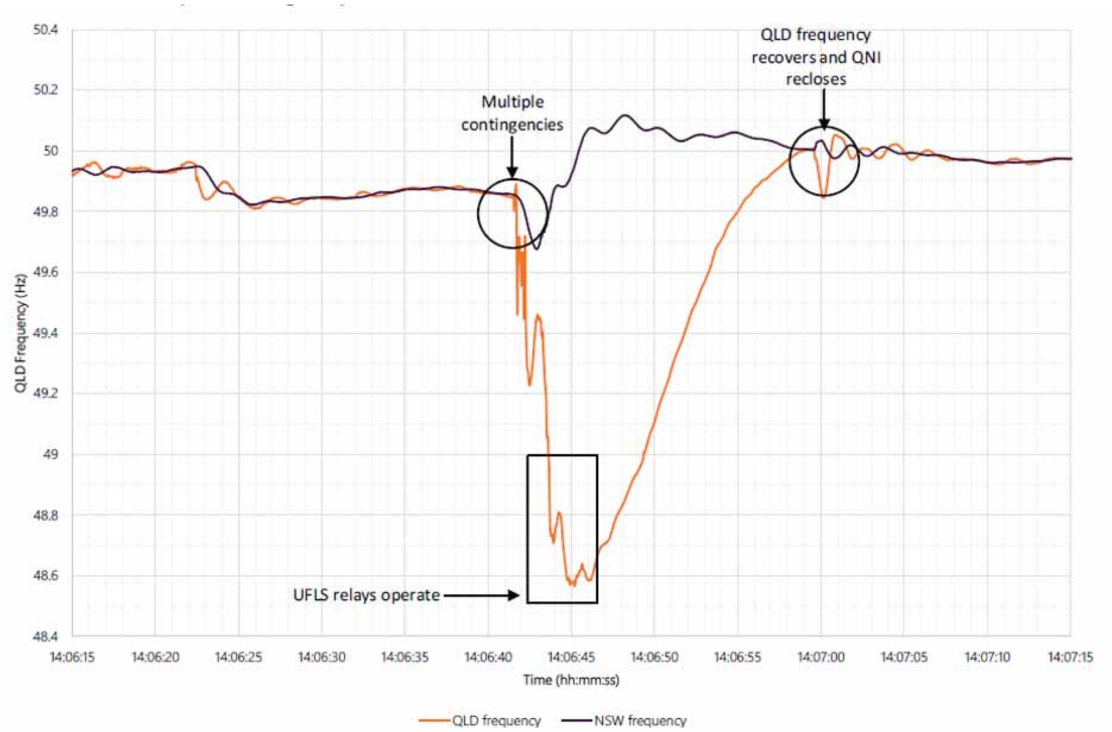
134 Shell Energy, Submission to the Issues paper, p.4.

135 AEMO, Power system frequency risk review, pp.31,35

136 Ibid.

137 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.14.

Figure 4.4: Queensland and New South Wales frequency profile during 25 May 2021 separation event



Source: AEMO, Enduring primary frequency response requirements for the NEM, 20 August 2021, p.42.
Note: Queensland frequency measured at Stanwell 275 kV substation Phasor Monitoring Unit.
Note: New South Wales frequency measured at Sydney West 330 kV substation Phasor Monitoring Unit.

Following this event AEMO noted that:[138]

> Tighter control of frequency as a result of widespread PFR in both Queensland and the rest of the NEM (as a result of the MPFR implementation) supported entirely automatic reconnection of these separated areas in around 15 seconds, as opposed to the minutes to hours it has taken for manual reconnection during previous Queensland separation events.

In recognition of the uncertainty associated with comparing historical power system events, the Panel arranged for the resynchronisation of separated power system regions to be investigated by GHD through power system modelling. This modelling approach is able to control scenario variables, such that a comparison based purely on different setting for the PFCB can be made. GHD's advice noted that:[139]

> Power system islands can only be re-synchronised when system voltages and

138 AEMO, Enduring primary frequency response requirements for the NEM, 20 August 2021, p.42.

139 GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.43

frequencies at connection points are close enough to allow breakers to close without damage. This requires careful monitoring of the voltages and frequencies on each island to determine that conditions are right for re-synchronisation. The success criteria for these studies were chosen to be when power system island frequencies were within 0.01% of each other, equivalent to 2 mHz.

Controlling frequency close to 50Hz provides separated regions with a common reference point that supports re-synchronisation. GHD's analysis demonstrates this through comparing the amount of time that the frequency of two separate regions meet the criteria for re-synchronisation over a sample 6-hour period for a wide and narrow PFCB setting. The results of this study are shown in Table 4.1.

Table 4.1: **Re-synchronisation of islanded regions**

PFCB — DEADBAND	PERCENT OF TIME SUCCESS CRITERIA MET — 2022	PERCENT OF TIME SUCCESS CRITERIA MET — 2033
15mHz	39.0%	45.4%
500mHz (including Contingency FCAS at 150mHz)	5.5%	4.1%

Source: GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.43.

The results of the GHD analysis indicate that tight control of system frequency around 50Hz — driven by a narrow setting for the PFCB — leads to a 7-fold increase in synchronisation criteria being met in the 2022 power system. This increases to an 11-fold increase for the 2033 power system.[140]

Distributed control through narrow band PFR provides redundancy in the event of central control system failure

Narrow band PFR — through a narrow setting of the PFCB — delivers additional resilience by way of providing an additional layer of distributed control through the collective action of each of the individual units of responsive plant dispersed throughout the power system. AEMO's advice notes that this distributed narrow band PFR provides redundancy in the event of contingency and separation events, as described above, but also in the event of failure or mal-operation of AEMO's automatic generation control system which provides centralised control of generators in the NEM.[141]

The power system events on 24 January 2021 provide an example of the benefit of this redundancy of controls. On this day, AEMO's Supervisory control and data acquisition

140 Ibid.

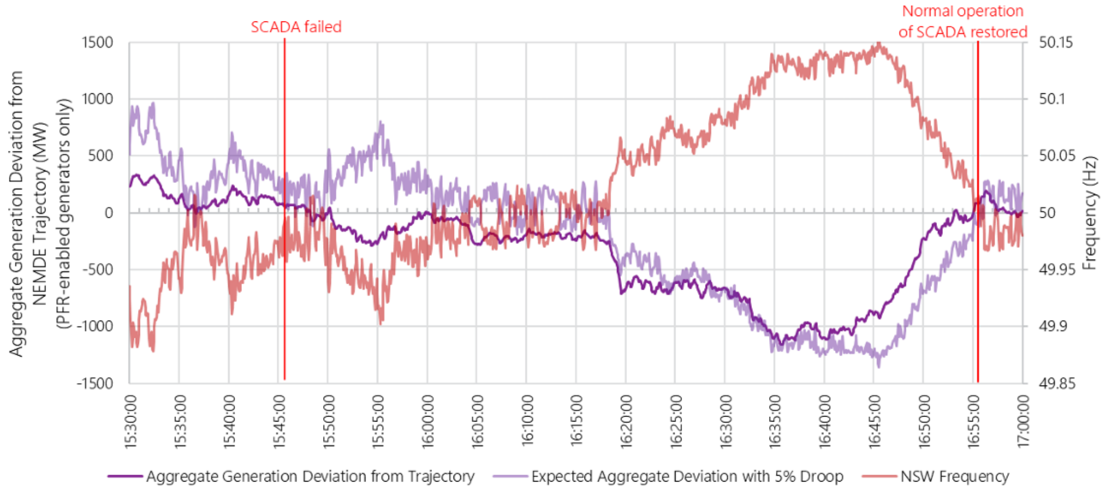
141 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.14.

(SCADA) system failed for a period of 1 hour and 10 minutes. As set out in AEMO's PFR Technical white paper:[142]

> During this period:
>
> - AEMO lost operational visibility of power system conditions and could not use SCADA for dispatch of generation or for centralised secondary frequency control.
> - AEMO's AGC was unable to ramp generation between market dispatch points, or control units enabled for Regulation FCAS.
> - Frequency remained within the requirements of the FOS throughout the incident, and did not depart the NOFB.

AEMO's analysis of power system behaviour during this event concluded that universal narrow band PFR provided by scheduled and semi-scheduled generators was instrumental in controlling system frequency during this period, despite the absence of central dispatch and regulation services. As shown in Figure 4.5 the responsive generation fleet provided an aggregate change in active power in response to system frequency that was able to maintain frequency within the NOFB. AEMO estimated that up to 1,157 MW of PFR was provided in the form of reduced generation — or frequency lower services — far beyond the volume of lower services enabled prior to the start of this event.

Figure 4.5: Figure Title



Source: AEMO, Enduring primary frequency response requirements for the NEM - Technical white paper, 20 August 2021, p.42.

AEMO noted that:

> Widespread PFR was able to automatically act in a coordinated manner to provide supply-demand balancing and frequency control, as it responds to the universal property of system frequency, rather than relying on centralised communication and

142 AEMO, Enduring primary frequency response requirements for the NEM - Technical white paper, 20 August 2021, p.42.

control processes via SCADA.

This example demonstrates how widespread narrow band PFR provides resilience benefits beyond the quantifiable impact on load-shedding as described in the GHD analysis on the resilience impacts of varying the PFCB.

4.2.3 A narrow setting for the PFCB delivers lower total costs for controlling system frequency

Consistent with stakeholder responses to the issues paper, a key focus of the Panel's consideration for this element of the FOS has been the analysis of the costs and benefits associated with different settings for the PFCB that directly relates to the expected range of power system frequency during normal operation. This analysis builds on the approach and methodology for pricing PFR, developed by the AEMC through the *Primary frequency response incentive arrangements* rule change.

Normal operation modelling methodology and assumptions

The GHD analysis used a single node power system model configured to represent the NEM power system in 2022 and 2033 (under the 2022 ISP step change scenario).

- Three six-hour periods were simulated using actual NEM SCADA data selected from the period 1 to 15 September 2021. The selected periods included the lowest, highest, and average levels of forecast errors throughout the two weeks.
- Two "study years", including
  - 2022 high Variable Renewable Energy (VRE) dispatch
  - 2022 low VRE dispatch
  - 2033 dispatch, to evaluate the impact of reduced coal plant and increased VRE generation.
- Generation types, including sub- and super-critical coal, wind, solar, BESS, CCGTs, OCGTs and hydro units.
- A subset of generation simulated units enabled to provide regulation services duty via a simplified AGC model.
- Different PFCB deadbands were tested, including 5, 15, 50 and 150 mHz across each study case.

Method for valuation of generator deviations

For each scenario, the power system model predicted the generator movements related to frequency control, relative to their dispatch setting. This included PFR movements, or deviations, and regulation FCAS movements.

Costs of the PFCB setting for the power system under normal operation have been estimated using the pricing methodology developed by the AEMC through the *Primary frequency response incentive arrangements* rule change. This pricing methodology is the basis for new frequency performance payment arrangements that will take effect in the NEM from 8 June 2025. The three major costs for frequency control during normal operation were therefore:

- Regulation enablement – which was assumed to be fixed and not changed irrespective of the PFCB setting.
- Regulation "work done" – which was calculated and priced on the same basis as PFR, with a fixed price paid per MW/hr of capacity used, based on historical R-FCAS NEM prices from the 2021 period.
- PFR "work done" – calculated with a fixed price paid per MW/hr of capacity used, based on historical NEM R-FCAS prices from the 2021 period.

The equation used for the calculation of the frequency performance payout for each 5-minute interval for regulation and PFR "work done" is shown in Figure 4.6.

Figure 4.6: Frequency performance payment equation

$$\mathbf{FPP} = CF\ x\ \frac{Price_{regulation}}{12}\ x\ RCR$$

Source: AEMC, Primary frequency response incentive arrangements — final determination, 8 September 2022, p.32.

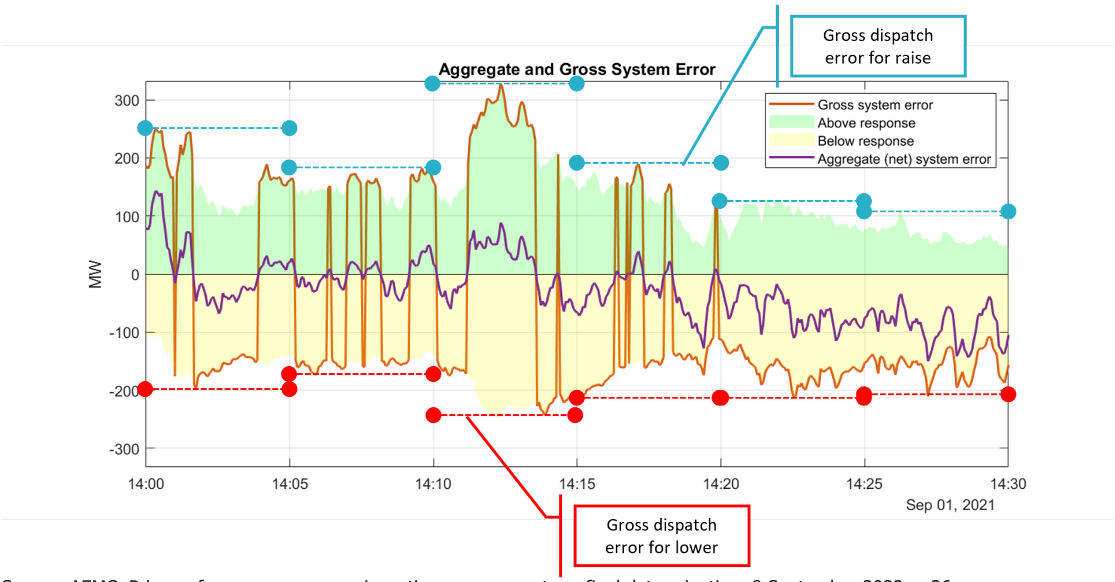
Note: **CF** is the contribution factor for each eligible unit - for the GHD analysis this value is 1 as the equation is applied to the aggregate generation fleet.

Note: **$Price_{regulation}$** ($/MWh) is the marginal price of meeting the global market ancillary service requirement or local market ancillary service requirement for the regulating raise service or regulating lower service in that trading interval;

Note: **RCR** is the Requirement for Corrective Response, measured in this case as the maximum and minimum aggregate MW deviation for all generation from their dispatch set-points across each 5-minute interval.

The requirement for corrective response (RCR) term is calculated based on the maximum and minimum values for aggregate raise and lower deviations over each 5-minute trading interval. This approach is shown graphically in Figure 4.7.

Figure 4.7: RCR — Aggregate (net) and gross dispatch error



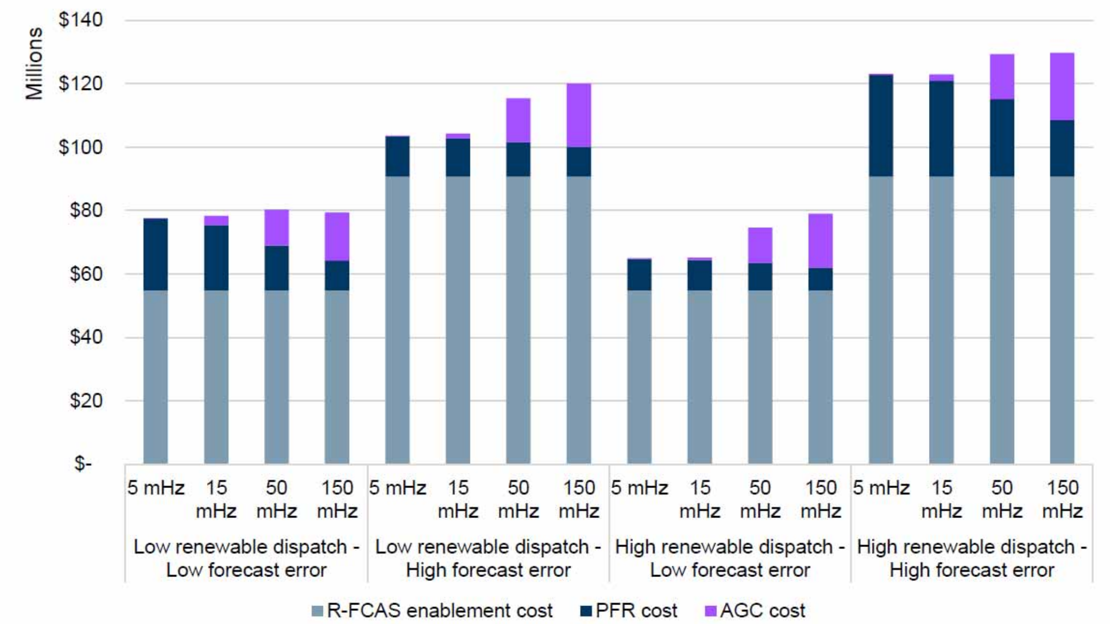
Source: AEMC, Primary frequency response incentive arrangements — final determination, 8 September 2022, p.36.

Normal operation modelling results — cost impact of varying the PFCB

The GHD analysis predicts that narrower settings for the PFCB would deliver lower total costs for control of power system frequency. The expected reduction in costs for narrower PFCB settings accounts for the costs of both PFR and regulation FCAS which work together to control frequency during normal operation. While the modelling predicted reductions in cost and duty for PFR deviation due to wider PFCB settings, the value of these reductions was modest and it was more than offset by increased costs and duty associated with the provision of regulation services.

The high-level results for the 2022 dispatch cases are set out in Figure 4.8.

Figure 4.8: Aggregate frequency control costs for different PFCB settings — annualised



Source: GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.iv.

The GHD analysis extended the investigation of operational costs relating to frequency control during normal operation to look at the behaviour of the generation fleet predicted in 2033 under the 2022 ISP step change scenario. While noting that the 2033 analysis was based on regulation FCAS prices for the 2021 sample period, the high level results for the normal operation study in 2033 were similar to the 2022 results, although the duty by technology reflected the increased proportion of inverter-connected plant and battery energy storage systems expected in the system in 2033.[143] GHD noted that:[144]

> The analysis found that a reduction in PFR work caused by the widening of the PFCB,

143 GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.iv.

144 Ibid., p.v.

> resulting in a decrease in PFR costs, was entirely offset by an increase in the requirement for R-FCAS providers to do work. Therefore, there was no compelling case to widen the deadband on this basis, as the system-wide costs marginally increased as the deadband was widened across a range of scenarios.

In relation to the results from the GHD normal operation modelling, the Panel notes that the costs associated with PFR and regulation duty combined are in the order of $10 million to $39 million or 18% — 43% of the costs for enablement of regulation services which range between $55 million and $91 million for these study scenarios. These costs align with the IES analysis on the expected net value of frequency performance payments in the order of $30 million per year, noting an average annual cost of $93 million per year for regulation enablement costs over the period 2019 - 2021.[145]

As part of the analysis, GHD also investigated how the scale of frequency performance payments provided to a battery energy storage system (BESS) compared to the levelised cost of energy required for economic operation of a BESS. This analysis measured the energy throughput for a BESS providing PFR and compared the associated cost to the anticipated frequency performance payment. The analysis found that, based on historical prices paid for frequency regulation in September 2021, payments were likely to sufficiently compensate the BESS for use of warranted BESS charge/discharge cycles to provide PFR.[146] This provides a reference to further validate the economic findings from the GHD normal operation study.

145 AEMC, Primary frequency response incentive arrangements — final determination, 8 September 2022, p.74.

146 GHD, Advice for the 2022 Frequency Operating Standard review - Power system and economic impacts due to variation of the PFCB, 21 November 2022, p.37

5 THE LIMIT FOR ACCUMULATED TIME ERROR

BOX 5: KEY POINTS IN THIS SECTION

Time error is a measure of the accumulated time the power system has spent away from the nominal frequency target of 50 Hz.

- Currently, the FOS requires AEMO to maintain accumulated time error on the mainland and Tasmania to less than 15 seconds except during islanded operation or during supply scarcity for the mainland or a multiple contingency event in Tasmania.
- The draft FOS removes the quantified limit on accumulated time error while retaining the requirement for this metric to be monitored and reported on. Therefore, there is no longer a requirement on how much accumulated time error may or may not exist. However, the Panel considers it is important that there still be transparency and knowledge about how much accumulated time errors exists. Therefore, the draft FOS states that:

  > Accumulated time error shall be monitored and reported on for the mainland and Tasmania

- This change to the FOS:
  - would improve the efficient operation of the power system by reducing the costs of ancillary services borne by market consumers
  - would be unlikely to have any detrimental impacts on consumers or any negative system security outcomes were time error allowed to accumulate.
- In submissions to the issues paper, stakeholders expressed scepticism of any system security or consumer benefits from limiting the accumulation of time error. However, time error was considered to be a valuable frequency performance metric and submissions recommended the Panel retain an obligation for AEMO to monitor and report on the accumulation of time error.

Time error is a measure of the accumulated time the power system has spent above or below exactly 50 Hz. If the real power system frequency is persistently above or below 50 Hz, even by a small amount, then the actual flow of energy in the system may differ slightly from that assumed through the energy market. Over time such variations, left unchecked, can accumulate thereby shifting resulting in a misalignment between synchronous and real time. Refer to section 7.1 of the issues paper for further explanation of time error.

The final determination for stage 1 of the 2019 review of the FOS relaxed the limit on accumulated time error in the mainland to 15 seconds, thereby harmonising the limit with the existing requirements in Tasmania.[147] At the time, the Panel also concluded that there may

147 Reliability Panel, Review of the frequency operating standard - stage one determination, 14 November 2016.

have been a case for the complete removal of the limit, taking into account any potential unforeseen impacts on large and small customers, once further consultation had been undertaken.

The draft FOS removes the quantitative limit on accumulated time error while retaining a requirement for monitoring and reporting obligations. The requirement to monitor and report on time error would continue to provide value to stakeholders as measure of system frequency performance, while the FOS would no longer set any hard limits on the allowable range for accumulated time error. This would provide AEMO with more flexibility in relation to how it manages time error and will allow system changes over time to support reductions in associated costs due to time error correction.

In determining these revised arrangements, the Panel has aimed to:

- Improve the **efficient operation** of the power system, in line with **consumer preferences**, by allowing for the costs of ancillary services to reduce while maintaining the existing reporting obligations to provide **transparency** for market participants.

This section includes the Panel's consideration of the appropriateness of the limit in the FOS for accumulated time error, including:

- Section 5.1 - Time error is a valuable frequency performance metric
- Section 5.2 - Time error accumulation has minimal impacts on consumers and the power system
- Section 5.3 - Relaxing the limit on time error will allow for reduced FCAS costs.

5.1 Time error is a valuable frequency performance metric

The Panel recognises that time error is a valuable metric for monitoring and reporting on frequency performance in the power system. This view is supported by most submissions to the issues paper.[148] As such, while the draft FOS removes the requirement for time error to be maintained below a set value, the existing level of monitoring and reporting that stakeholders have grown accustomed to would be maintained.

AEMO has provided expert advice to this review on the limit for accumulated time error in the FOS. It advised that there were no clear benefits to system security or consumers from time error correction. However, the inclusion of a standard in the FOS does enable AEMO to monitor and report on developments, thereby providing stakeholders with a valuable source of transparency. As such, AEMO's advice to the Panel concluded that:[149]

> While removing the time error standard entirely would be unlikely to lead to any direct issues, the standard nonetheless [provides] transparency to the market and consumers [in] ensuring that the total energy delivered into the grid aligns with expectations.

148 Submissions to the issues paper: AEC, p.5; Energy Australia, p.4; TasNetworks, p.6; Iberdrola, p.6; Shell Energy, p.5; Origin Energy, p.2.

149 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.61.

AEMO's advice recommended that the Panel consider removing the limit on accumulated time error from the FOS, but retain the existing monitoring and reporting obligations.[150]

The Panel considers that it would not be in the long-term interest of consumers to retain the standard in a FOS. While retaining a looser limit in the FOS could allow AEMO to periodically reset time error, the Panel did not consider that there were security or economic benefits that would justify maintaining the standard in the FOS. This was supported by GHD's survey that found only the NEM and WEM include a standard in their frequency operating standards for accumulated time error.[151]

The Panel has instead included a requirement for AEMO to monitor and report on time error accumulation. Under clause 4.8.16(b)(2) of the NER, AEMO will continue to prepare and publish quarterly reports on the achievement of the FOS including rate of time error accumulation in the NEM and Tasmania. This will retain the same level of transparency for stakeholders. It will also allow active monitoring for any unforeseen consequences from this change that might exist.

Stakeholders see time error as a valuable performance metric and diagnostic tool

In submissions to the issues paper, stakeholders expressed their preference to continue the current reporting requirements. This preference did not rely on the obligations for AEMO to correct for time error. This view was voiced in submissions by TasNetworks, the AEC, Energy Australia, Iberdrola and Origin Energy who supported maintaining time error measurement as a diagnostic metric to indicate any potential imbalances in electricity systems.[152]

The Panel agrees with stakeholders that maintaining the current monitoring and reporting obligations were in the best long-term interests of consumers. The draft FOS would require AEMO to continue to monitor and report on time error accumulation as a metric of power system performance.

5.2 Time error has minimal impacts on consumers and the power system

The Panel considers it important that any change to the accumulated time error settings in the FOS not result in a deterioration of security outcomes nor place an undue burden on market participants or AEMO. In revising the settings for time error, the Panel considers the effect it would have on customers that potentially still rely on synchronous time to not be significant.

In 2019, the Reliability Panel increased the limit on accumulated time error in the mainland from 5 to 15 seconds. As part of the determination, the Panel noted that:[153]

> Following a suitable period of monitoring, it may be appropriate for the Panel to

150 Ibid.

151 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.33

152 Submissions to the issues paper: AEC, p.5; Energy Australia, p.4; TasNetworks, p.6; Iberdrola, p.6; Shell Energy, p.5; Origin Energy, p.2.

153 Reliability Panel, Review of the Frequency Operating Standard - Stage 2, Final Determination, 18 April 2019, p.40.

> consider further changes to the limit in the FOS in relation to accumulated time error

The following sections summarise the Panel, AEMO and stakeholders improved understanding of the consequences of further relaxing the limit on accumulated time error.

5.2.1 Time error has minimal impacts on electricity consumers

The materiality of the accumulation of time error on residential, commercial or industrial consumers has been considered by the Panel as part of this review. The Panel considered whether the costs incurred to correct for time error would be balanced by the potential benefits from retaining the synchronicity between real and system time. Otherwise, maintaining the standard would not be in the long term interests of consumers.

The Panel concluded that removing the obligation for AEMO limit time error to a specific value is unlikely to negatively affect market participants or consumers.

This position is consistent with the previous review of the FOS which raised the possibility of abolishing the requirement altogether following further consultation.[154]

GHD's survey of system operators and regulators supported the Panel's hypothesis that it is unlikely that removing the requirement in the FOS would have an adverse effect on consumers. GHD stated:[155]

> All survey respondents agree that an accumulated time error is unlikely to impact customers adversely.

Stakeholders did not see much consumer benefit in correcting time error

Submissions to the issues paper expressed doubts about the consumer benefits from time error correction. Most stakeholders agreed that removing the requirement for AEMO to correct for time error accumulation would be unlikely to have material impacts on consumers.[156] The AEC, TasNetworks and Energy Australia noted that AEMO has on several occasions reset time error without any discernible impact on consumers or the system overall. However, Shell Energy's submission noted that the Panel should be better informed on the potential impact and unintended consequences were it to remove the obligation on AEMO to correct for time error accumulation.[157]

The Panel agrees with stakeholders that time error correction does not result in improved consumer well-being. As such, it is unlikely that consumers would be affected by the removal of the limit on time error accumulation in the FOS.

154 Reliability Panel, Review of the Frequency Operating Standard - Stage one, Final Determination, 14 November 2016, p.51.

155 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.iii

156 Submissions to the issues paper: AEC, p.5; Energy Australia, p.4; TasNetworks, p.6; Iberdrola, p.6; Shell Energy, p.5; Origin Energy, p.2.

157 Submission to the issues paper: Shell Energy, p.5.

5.2.2 Removing the limit on accumulated time error is unlikely to affect system security

AEMO's advice on the appropriateness of the current settings on accumulated time error concluded that there were no system security or reliability benefits from continuing time error correction. Additionally, these corrections resulted in higher costs with the increased procurement of ancillary services.

Frequency is generally less controlled in Tasmania compared to the mainland as they are two very different power systems. Tasmania is predominantly hydro-electric and VRE powered, is a relatively small system and has a proportionally large DC interconnector. Operating experience in the state has provided the Panel with valuable insight into the practical effect on system security of cancelling accumulated time error. In FY2022, AEMO manually reset time error on 3 separate occasions without any apparent negative effects on system security or reliability.[158]

The key findings from GHD's jurisdictional survey further reinforced the Panel's position that the removal of obligations to correct for time error would have an immaterial effect on security and consumers. GHD concluded that:[159]

> Some survey respondents reported that time error was monitored while others identified that time error was ignored. Some [operators] track time error as a performance metric.

When deciding to abolish the regulatory requirement to correct time error, the North American Electricity Reliability Corporation (NERC) noted it is possible applying an offset from the 50 Hz target frequency (60 Hz in the United States) could have detrimental impacts on the reliability of the power system. NERC concluded that:[160]

> The [Standard Drafting Team] (SDT) believes there is not a reliability reason to continue Time Error Corrections. The SDT also believes Time Error Corrections as currently implemented are detrimental to reliability. Given this, the SDT proposes to halt the use of Time Error Corrections in North America.

While AEMO raised a concern that uncontrolled drift in time error may have detrimental effects on system security, the Panel determined omitting the requirement would not preclude AEMO from correcting for time error. AEMO is able to implement time error correction under clause 4.4.1 of the NER.[161] Moreover, the Panel does expect AEMO to continue to take time error into consideration in a multitude of legacy constraints as outlined in AEMO's advice:[162]

> Removing unnecessary obligations is prudent as it streamlines operating practices, the cost and effort involved in managing time error in the mainland has been relatively

158 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.60.

159 GHD, Advice for the 2022 Frequency Operating Standard review - System Rate of Change of Frequency, 18 November 2022, p.33

160 NERC, Time Error Correction, September 2015, p.3.

161 Under clause 4.4.1 of the NER, AEMO retains the responsibility to use reasonable endeavours to control power system frequency.

162 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.61.

low. Furthermore, there would be some effort involved in removing time error management from all processes and procedures and some risk of impacting other NEM processes.

Stakeholders did not consider there to be material security impacts

Submissions to the issues paper agreed that removing the requirement for AEMO to correct for time error accumulation would be unlikely to have material impacts on system security or electricity consumers. The AEC, TasNetworks and Energy Australia noted AEMO's resetting of accumulated time error in Tasmania as justification for the view.[163]

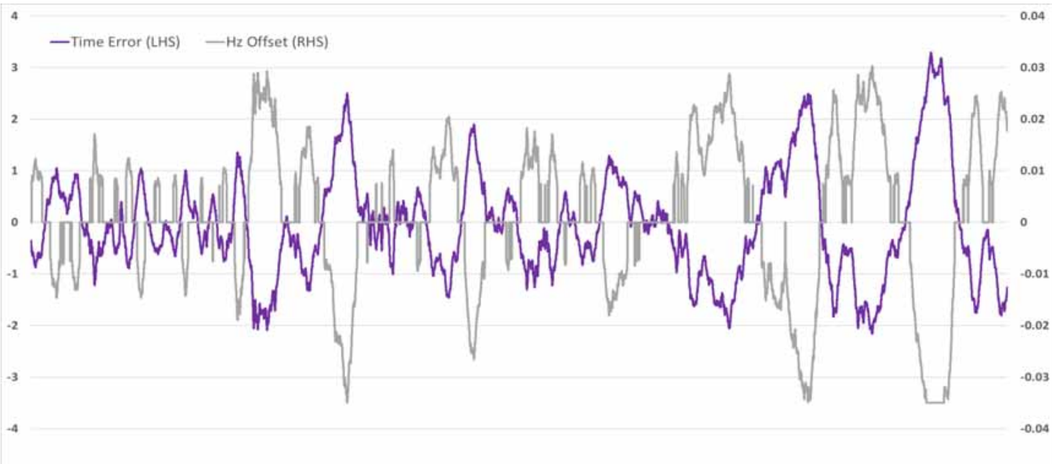
The Panel agrees with stakeholders that abolishing the limit on time error accumulation is unlikely to have an impact on system security or consumers. This is clearly illustrated by the uneventful occasional resetting of time error in Tasmania.

5.3 Relaxing the limit on time error will allow for reduced FCAS costs

5.3.1 There is a cost for correcting time error through regulation FCAS

To correct the accumulation of time error, AEMO applies a small frequency offset to run the power system marginally above (or below) the nominal frequency of 50Hz for a period of time. This process is referred to as time error correction and leverages the AGC system by controlling units enabled to provide regulation FCAS. Figure 5.1 below illustrates the regularity with which AEMO introduced a frequency bias over the first week of 2022.

Figure 5.1: Time error accumulation and offset over 1 week starting 1 January 2022



Source: AEMO, Frequency and time deviation monitoring — annual frequency data, 12 September 2022.

The Panel's previous review of the FOS considered the value of maintaining synchronicity with real-time given the replacement of synchronous clocks by modern alternatives. AEMO's advice to the 2019 FOS review estimated the costs incurred, over the timespan between

163 Submissions to the issues paper: AEC, p.5; Energy Australia, p.4; TasNetworks, p.6.

January 2016 to June 2017, to be on the order of $1 million per annum in increased regulation FCAS costs.[164]

AEMO's advice to the current Panel review of the FOS has leveraged a different calculation methodology thereby resulting in increased estimated costs.[165] As such AEMO noted that:

> Estimated costs for FY2022 of approximately $1.9 million per annum are lower than estimated costs for FY2017 of approximately $2.8 million per annum.

It is important to note that the introduction of mandatory PFR and the considerable increase in base regulation FCAS volumes applied could have influenced the calculation of the estimated cost of time error correction. AEMO believes that the recent improvements in frequency performance have resulted in reduced correction costs.

Stakeholders have doubts about the value of correcting for time error

Submissions to the issues paper by TasNetworks, the AEC, Energy Australia and Iberdrola indicated that most stakeholders questioned the value of performing time error correction.[166] Iberdrola in particular noted that using a frequency offset may complicate the calculation of the primary frequency response performance payments under the PFR incentive arrangements rule and the AEC noted time the bias introduces an error into causer-pays calculations.

The Panel agrees with stakeholders that there is no economic rationale for requiring AEMO to limit time error accumulation. Moreover, the Panel acknowledges the AGC bias used to correct for time error could have a detrimental impact on the causer-pays and frequency performance payments calculation.

164 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard - Stage 1, 2019, p.5

165 AEMO, Advice to the Reliability Panel for the review of the frequency operating standard, September 2022, p.56

166 Submissions to the issues paper: AEC, p.5; Energy Australia, p.4; TasNetworks, p.6; Iberdrola, p.6; Shell Energy, p.5; Origin Energy, p.2.

ABBREVIATIONS

AC	Alternating current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic generation control system
Commission	See AEMC
Cl	Clause
DC	Direct current
DNSP	Distribution network service provider
EFCS	Emergency frequency control scheme
FCAS	Frequency control ancillary service
FFR	Fast frequency response
Hz	Hertz
ISP	Integrated system plan
MASS	Market ancillary service specification
MCE	Ministerial Council on Energy
MPFR	Mandatory primary frequency response
NEL	National Electricity Law
NEM	National electricity market
NEMDE	National electricity market dispatch engine
NEO	National electricity objective
NERL	National Energy Retail Law
NOFB	Normal operating frequency band (49.85 — 50.15 Hz)
NOFEB	Normal operating frequency excursion band (49.75 — 50.25 Hz)
NSP	Network service provider
OFGS	Over frequency generation load shedding
OFTB	Operational frequency tolerance band
PFCB	Primary frequency control band
PFR	Primary frequency response
PFRR	Primary frequency response requirements
RoCoF	Rate of change of frequency
SCADA	Supervisory control and data acquisition
TNSP	Transmission network service provider
UFLS	Under frequency load shedding scheme

A CONSULTATION AND DEVELOPMENT PROCESS

A.1 The AEMC provided a terms of reference to the Panel about how to conduct this review

On 28 April 2022, the AEMC provided Terms of Reference to the Panel to initiate a review of the FOS (the Review). These can be found on the project page for the review on the AEMC website.[167]

Among other things, the Terms of Reference require the Panel to consider:

- Whether the terminology, standards, settings and definitions in the FOS remain appropriate.
- The settings in the FOS that apply for normal operation, including:
  - The normal operating frequency band (NOFB)
  - The normal operating frequency excursion band (NOFEB)
  - The requirement that:

    Except as a result of a contingency event or a load event, system frequency:

    a) shall be maintained within the applicable normal operating frequency excursion band, and

    b) shall not be outside of the applicable normal operating frequency band for more than 5 minutes on any occasion and not for more than 1% of the time over any 30 day period.

- The Primary frequency control band referred to in clause 4.4.2A of the NER.
- The settings in the FOS for credible and non-credible contingency events.
- What amendments to the FOS may be necessary and appropriate to support the implementation of market arrangements for fast frequency response (FFR). This may include the specification of system operating standards for the rate of change of frequency (RoCoF) and other settings as appropriate.

The Panel is required to complete its review by 7 April 2023. This will allow for a period of at least 6 months from the date the revised FOS is determined to the date that the new market ancillary service arrangements for FFR commence on 9 October 2023.

The Commission also requested that the final report include the Panel's recommendation on the timing for the next review of the FOS.

A.2 The Panel has received advice from AEMO to support its review

The NER requires that the Panel's determination of the FOS be made "on the advice of AEMO".[168] Therefore, in addition to consulting with key stakeholders and the engagement of

167 Refer to the project webpage.

168 Clause 8.8.1(a)(2) of the NER.

independent advice, the Panel has received draft advice from AEMO to support its review and determination of the draft FOS.

On 12 July 2022, the Panel formally requested expert advice on the system security and operational implications of each of the issues for consideration as part of this review. The correspondence is available on the AEMC webpage.[169] The identified issues for consideration were:

1. **Frequency performance during normal operation**, including:
    a. The target distribution for frequency during normal operation – in the absence of contingency events.
    b. The specification of the primary frequency control band which set a lower bound for the maximum allowable deadband that AEMO may specify for affected generators as part of the Mandatory PFR requirements. The PFCB is currently specified in the NER as 49.985 – 50.015 Hz, or such other range as specified by the Panel.
2. **Limits on rate of change of frequency (RoCoF) for the power system** – the Panel is considering the inclusion of system limits for RoCoF in the FOS to better specify the requirements for frequency control in the context of reducing system inertia and the commencement of market ancillary service arrangements for fast frequency response contingency reserves.
3. **The settings for contingency events**, including:
    a. the existing frequency containment and recovery bands that apply for credible generation, load and network events
    b. the existing frequency containment and recovery bands that apply for non-credible contingency events and protected events
    c. the operational frequency tolerance band that applies during conditions of supply scarcity
    d. the existing limit of 144MW for the largest allowable generation event in the Tasmanian system
    e. whether the generation limit in Tasmania should be extended to apply to network and load events
    f. whether the FOS should include a limit on the maximum credible contingency event for the mainland system.
4. **The limit on accumulated time error**, including whether the limit on accumulated time error should be further revised or abolished.

The Panel has published a draft copy of AEMO's advice as a companion to its draft determination.[170]

169 Refer to the project webpage.
170 Ibid.

A.3 Independent advice and modelling

The AEMC engaged GHD to provide independent technical and economic advice and inform the Panel's Review of the FOS. This advice complements the technical advice provided by AEMO, both of which have been published alongside the Panel's draft determination.[171] The modelling and analysis elements were divided into three main sub-tasks:

- in Task 1a: Normal operation and PFR study, GHD applied a simplified NEM model to quantify the impacts of varying the PFCB
- in Task 1b: Modelling of PFR resilience benefits, GHD studied the resilience impacts due to variation of the PFCB settings for various operating scenarios and contingency events in the present and future power system
- in Task 1: RoCoF analysis and survey, GHD studied comparative systems to identify approaches to manage increasing contingency size, RoCoF and time error accumulation.

The Panel has published a draft copy of AEMO's advice as a companion to its draft determination.[172]

A.4 Consultation process

In carrying out this review, the Panel is following a consultation process consistent with clause 8.8.3 of the NER and the Terms of Reference. The Panel has consulted with stakeholders through seeking submissions to the issues paper and this draft determination. The Panel will also carry out face to face meetings and a public forum may be arranged as required at the request of stakeholders. Key dates for the review are shown in Table A.1.

Table A.1: **Timetable for the review**

MILESTONE	PROPOSED DATE
Publish issues paper and terms of reference	28 April 2022
Public forum	27 May 2022
Close of submissions to the issues paper	9 June 2022
Receive draft AEMO advice	30 September 2022
Publish draft determination	8 December 2022
Publish final determination	By 7 April 2023
Proposed implementation date for the revised FOS	9 October 2023

A.4.1 Issues paper

The issues paper initiating this review of the FOS was published by the Panel on 28 April 2022. The paper set out the issues for consideration relating to the FOS for stakeholder comment. It was the first of a series of opportunities that stakeholders will have in providing

171 Refer to the project webpage.
172 Ibid.

input on the Panel's determination. There were four key issues that the Panel outlined in the paper to which it asked for stakeholder consultation:

- settings in the FOS for normal operation
- the potential inclusion of a system standard for RoCoF
- the settings in the FOS for contingency events
- the limit on accumulated time error.

Submissions to the issues paper were due by 9 June 2022. The Panel received 11 stakeholder submissions in total. The Panel has taken into account stakeholder comments in making its draft determination.

B BACKGROUND AND CONTEXT

This appendix sets the context for this review including a summary of recently completed and ongoing work programs related to this review of the FOS.

The issues paper for this review provides a description of the elements of the FOS, the concept of power system frequency and frequency control and the NEM's frequency control frameworks.

This appendix includes discussion of:

- Appendix B.1 - The FOS in the NEM
- Appendix B.2 - Frequency performance in the NEM
- Appendix B.3 - Related Work Programs and rule changes.

B.1 The FOS in the NEM

The purpose of the FOS is to define the range of allowable frequencies for the electricity power system under different conditions, including normal operation and following contingencies. Generator, network and end-user equipment must be capable of operating within the range of frequencies defined by the FOS, while AEMO is responsible for maintaining the frequency within the ranges defined by these standards.

See section 2 of the issues paper for further information on the role of the FOS.

B.2 Frequency performance in the NEM

As described in appendix A, the Panel is undertaking this review of the FOS in response to a terms of reference provided by the AEMC. At the same time this review takes place during a time of rapid technological and behavioural change in the power system.

This section explores the recent frequency performance in the NEM, including:

- the frequency performance following the introduction of mandatory primary frequency response (PFR)
- continued improvements in frequency performance in the mainland and Tasmania.

B.2.1 Frequency performance has improved following the introduction of mandatory PFR

As the issues paper identified, power system frequency performance during normal operation degraded significantly over the period 2015 – 2020.[173] This degradation of frequency performance was observed in a widening of the distribution of frequency during normal operation, an increased incidence of oscillations in the power system frequency and a decrease in the resilience of the power system to non-credible contingency events.

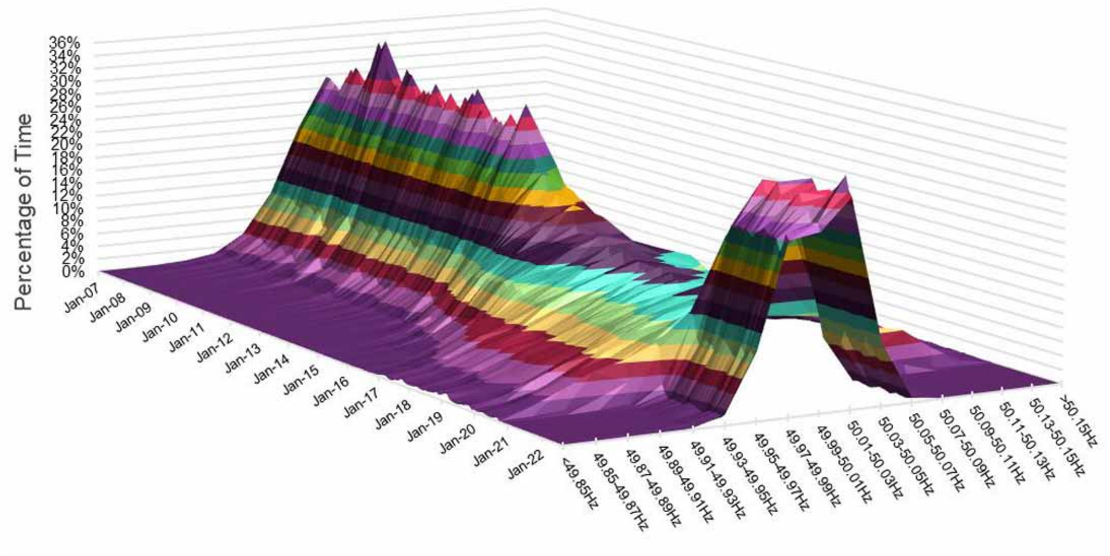
In response rule changes were submitted to the AEMC from AEMO and from Dr Peter Sokolowski. A final determination was made by the AEMC in December 2020 which required,

173 Reliability Panel, Review of the frequency operating standard, Issues paper, 28 April 2022

amongst other things, all scheduled and semi-scheduled generators who received a dispatch instruction to generate to a volume greater than 0 MW, must operate their plant in accordance with the performance parameters set out in the primary frequency response requirements (PFRR) as applicable to that plant. The AEMC also considered that the mandatory arrangements on their own were not sufficient and so also put in place a proposed sunset for these arrangements to allow time for incentives to be developed. These were considered through the *primary frequency response incentives* rule change.

The implementation of mandatory PFR from late 2020 lead to a significant improvement in power system frequency performance during normal operation.[174] The much improved control over power system frequency is illustrated in Figure 2.2 below.

Figure B.1: NEM Frequency distribution - 2007 to 2022



Source: AEMO, Frequency and Time Error Monitoring - Quarter 3 2022, November 2022, p.7.

B.2.2 Continued improvements in frequency performance in the mainland and Tasmania

In its frequency and time error monitoring report for Q4 2021, AEMO noted that:[175]

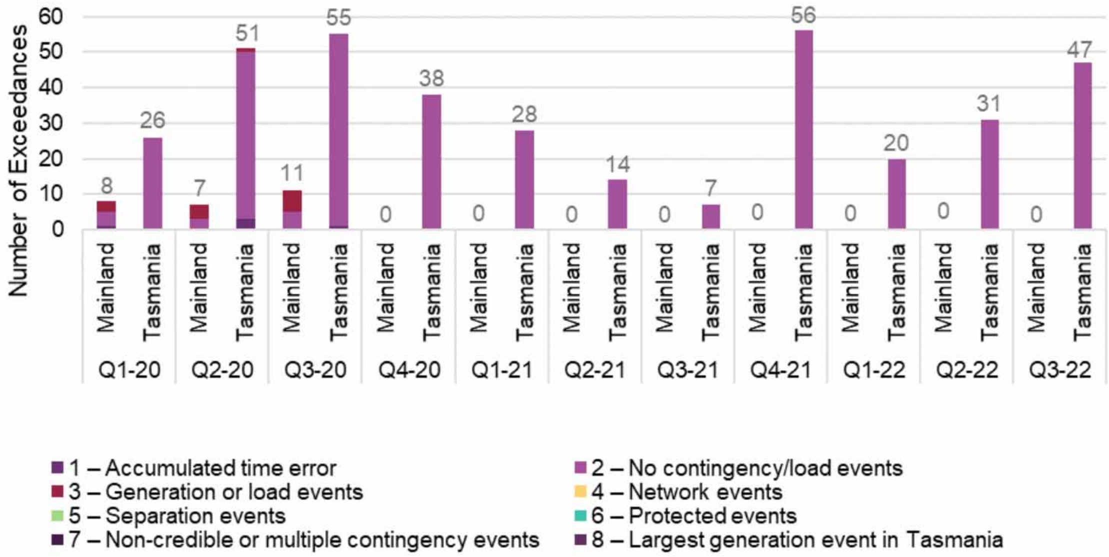
> Since the implementation of the Mandatory PFR rule commenced, there has been a significant reduction in the number and length of frequency excursions from the NOFB and a corresponding increase in time spent within the NOFB. When contingency events did occur, frequency was contained earlier or recovered to the NOFB faster than experienced during similar events before Mandatory PFR commences.

The number of excursions outside of the FOS requirements in the mainland has continued to remain at a low level, following the introduction of mandatory PFR, as shows in Figure B.2.

174 AEMO, Enduring PFR requirements for the NEM - White Paper, August 2021, p.3.

175 AEMO, Frequency and Time Error Monitoring — Quarter 4 2021, February 2022, pp.12-13.

Figure B.2: FOS exceedances in the mainland and Tasmania



Source: AEMO, Frequency and Time Error Monitoring - Quarter 3 2022, November 2022, p.10.

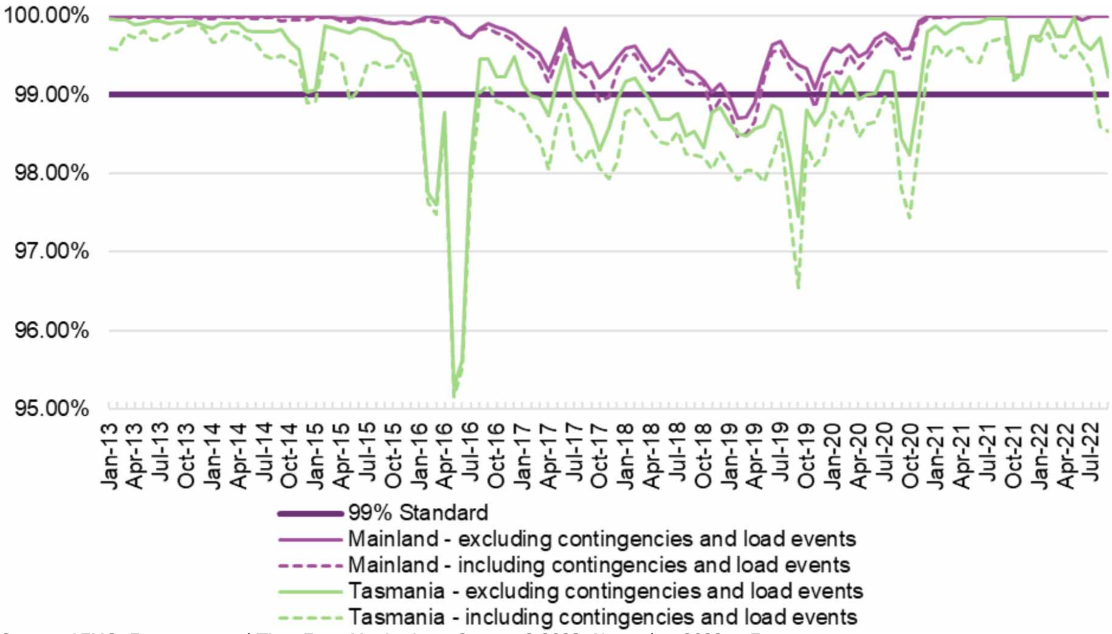
Frequency performance within the NOFB

Figure B.3 shows that the frequency in the mainland did not exceed the NOFB for more than 1% of the time between Q4 2020 and Q3 2022. Following the introduction of the mandatory PFR rule, there has been a significant reduction in the number and length of frequency excursions from the NOFB. When contingency events did occur, the frequency was contained and recovered faster than before mandatory PFR.

While frequency performance in the mainland has met the requirements of the FOS since Q4 2020, there continues to be a considerable number of FOS exceedances in the Tasmanian region in the absence of contingency events. AEMO's analysis of these exceedances notes that the majority occurred during periods where Basslink was out of service and are characteristic of the frequency performance for the small Tasmanian system in the absence of the Basslink frequency controller.[176]

176 AEMO, Frequency and Time Error Monitoring – Quarter 3 2022, 11 November 2022, p.10.

Figure B.3: Frequency in NOFB since January 2013 - minimum daily time percentage in prior 30-day window



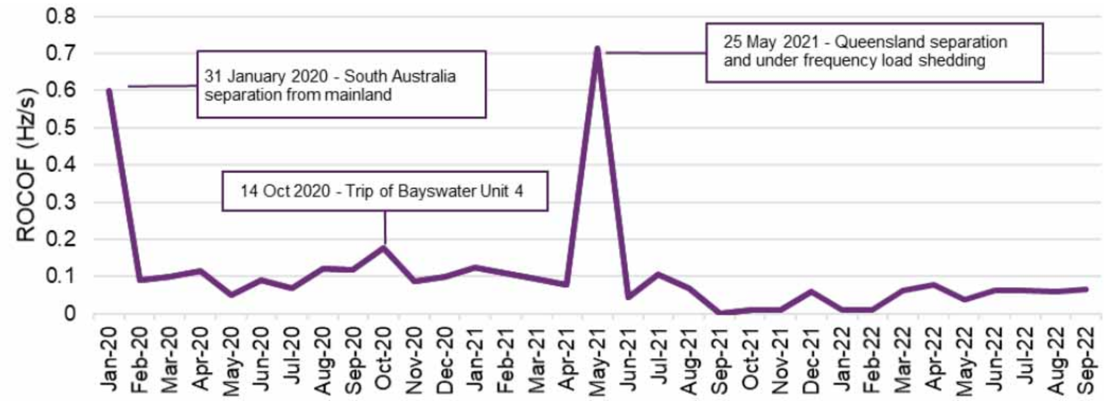
Source: AEMO, Frequency and Time Error Monitoring - Quarter 3 2022, November 2022, p.7.

Maximum RoCoF in the mainland NEM

Figure B.4 shows that the maximum RoCoF recorded in the mainland NEM since January 2020 occurred on 25 May 2021, when Queensland separated from the mainland NEM following the loss of multiple Queensland generators. The greatest RoCoF recorded in the mainland in Q3 2022 was -0.067 Hz/s following the trip of the Stanwell Unit 4 at 364MW in September 2022.[177]

177 AEMO, Frequency and Time Error Monitoring - Quarter 3 2022, November 2022, p.11.

Figure B.4: **Monthly maximum RoCoF recorded in any mainland region in 2020-22**



Source: AEMO, Frequency and Time Error Monitoring - Quarter 3 2022, November 2022, p.11.
Note: 31 January 2020 RoCoF as measured in South Australia and 25 May 2021 RoCoF as measured in Queensland.

See section 2 of the issues paper for further information on NEM frequency performance.

B.3 Related Work Programs and rule changes

The Panel's review of the FOS relates to and has been informed by relevant work being undertaken by AEMO and the AEMC. This includes:

- AEMO's *Engineering Framework*.[178] AEMO is investigating and defining the operational, technical and engineering requirements needed to meet system requirements in the NEM over then next five to ten years. The objective of the framework is to help facilitate an orderly transition to a secure and efficient future NEM system. In December 2021, AEMO published an initial roadmap that set out a series of potential gaps that may require action to meet the future needs of the power system.

  The gaps identified by AEMO as part of the *Engineering Framework* that are relevant to frequency control and this review of the FOS are outlined in the issues paper.

- AEMO's review of the MASS — FFR specification. AEMO is currently undertaking a review of the MASS given the upcoming development and implementation of new FFR markets.

  The Panel understands that the consideration of a rate of change of frequency (RoCoF) standard will be an input for AEMO's FFR implementation process, including the specification in the MASS and the development of constraints to support the dispatch of FFR services. The Panel understands that the interaction between the FFR specification and the FOS will be considered by AEMO and factored into its advice to the Panel for the review of the FOS.

- The AEMC's assessment of the *Primary frequency response incentive arrangements* rule change.[179] The AEMC is currently considering how best to create enduring arrangements

178 AEMO, Engineering Framework - Initial Roadmap, December 2021, pp.26-27.

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

that incentivise primary frequency response to complement the mandatory primary frequency response arrangements. A final determination on this was published in September 2022.

The rule change confirmed the mandatory PFR requirements for market participants. The FOS settings for normal operation will set the target for frequency performance, which the PFR incentives may help AEMO achieve.

- The AEMC's assessment of the *Operational security mechanism* rule change.[180] The AEMC is considering options for the scheduling and provision of essential system services (ESS) to ensure the power system remains secure, in response to rule change requests from Hydro Tasmania and Delta Electricity. A draft determination for this rule change was published in September 2022.

  The proposed RoCoF standard being considered as part of this review, may guide AEMO's procurement of security services through the operational security mechanism.

- The AEMC's assessment of the *Efficient provision of inertia* rule change.[181] The Australian Energy Council have submitted a rule change request to the AEMC to implement an inertia market. The AEMC has not yet initiated this rule change request.

  The Panel understands that the draft RoCoF standard could guide AEMO on the procurement of inertia through a potential market ancillary service.

180 See: https://www.aemc.gov.au/rule-changes/operational-security-mechanism

181 See: https://www.aemc.gov.au/rule-changes/efficient-provision-inertia

C DRAFT FREQUENCY OPERATING STANDARD- MARKUP

Note: This appendix provides a markup of the draft FOS with respect to the FOS that came into effect from 1 January 2020.

The *frequency operating standard* forms part of the *power system security standards*.

The Panel has determined to amend the frequency operating standard, in accordance with clause 8.8.3(a)(1) of the *Rules* with effect from ~~1 January 2020~~9 October 2023.

In this document:

- Appendix C.1 — specifies the *frequency* bands for the purpose of the *frequency operating standard* and the *Rules*
- Appendix C.2 — specifies the required **system frequency** outcomes following specified events
- Appendix C.3 — contains the definitions used in this document.

C.1 Frequency bands

The frequency bands are shown in Table C.1.

For the purpose of the *frequency operating standard* and the *Rules*, a term in Column 1 means the *frequency* range in Column 3 for an **island**, Column 4 during **~~supply scarcity~~system restoration** in the mainland and Column 2 in all other conditions (**Normal**).

Table C.1: Frequency bands

COLUMN 1	COLUMN 2		COLUMN 3		COLUMN 4
	NORMAL (HZ)		ISLAND (HZ)		S~~UPPLY SCARCITY~~YSTEM RESTORATION (HZ)
	MAINLAND	TASMANIA	MAINLAND	TASMANIA	MAINLAND
primary frequency control band	49.985 – 50.015				
normal operating frequency band	49.85 – 50.15		49.5 – 50.5	49.0 – 51.0	49.5 – 50.5
normal operating frequency excursion band	49.75 – 50.25		49.5 – 50.5	49.0 – 51.0	49.5 – 50.5
operational frequency tolerance band	49.0 – 51.0	48.0 – 52.0	49.0 – 51.0	48.0 – 52.0	48.0 – 52.0
extreme frequency excursion tolerance limit	47.0 – 52.0	47.0 – 55.0	47.0 – 52.0	47.0 – 55.0	47.0 – 52.0

Note: 1. The Reliability Panel has not determined separate *frequency* bands for periods of ~~**supply scarcity**~~**system restoration** in Tasmania. Where a state of ~~**supply scarcity**~~**system restoration** exists for the Tasmanian power system, the *frequency* bands set out in column 2 of table A.1 apply for an intact *power system*, and the *frequency* bands set out in column 3 of table A.1 apply for an **island** with the Tasmanian *power system*.

C.2 Required frequency outcomes

The target **system frequency** for the mainland and Tasmania is 50 Hz.

Accumulated time error must be monitored and reported on for the mainland and Tasmania.

The *power system* is expected to experience a range of different operating conditions. Table C.2 — Table C.7 detail the required **system frequency** outcomes following the occurrence of the events specified in each Table.

Table C.2: **System frequency outcomes following specified conditions**

	REQUIREMENT	MAINLAND	TASMANIA
~~1~~	~~**Accumulated time error** limit.~~	~~<15 seconds, except for an **island** or during **supply scarcity**~~	~~<15 seconds, except for an **island** or following a **multiple contingency event**~~
1	Except as a result of a *contingency event* (which may be a **generation event**, a **load event** or a **network event**), **system frequency**: a) ~~shall~~ must be maintained within the applicable normal operating frequency excursion band, and b) ~~shall~~ must not be outside of the applicable normal operating frequency band for more than 5 minutes on any occasion and not for more than 1% of the time over any 30-day period.		
2	Following a **generation event** or a **load event**, **system frequency** must be maintained within the applicable **generation and load change band**, and must not be outside of the applicable *normal operating frequency band* for more than…	…5 minutes	…10 minutes
3	Following a **network event**, **system frequency** must be maintained within the applicable *operational frequency tolerance band*, and must not be outside of …	…the applicable **generation and load change band** for more than 1 minute, or be outside of the applicable *normal operating frequency band* for more than 5 minutes.	…the applicable *normal operating frequency band* for more than 10 minutes.

	REQUIREMENT	MAINLAND	TASMANIA
4	Following a **separation event**, **system frequency** must be maintained within the applicable island separation band, and must not be outside of the applicable **generation and load change band** for more than 2 minutes, or be outside of the applicable *normal operating frequency band* for more than 10 minutes.		
5	Following a *protected event*, **system frequency** must be maintained within the applicable extreme frequency excursion tolerance limit, and must not be outside of the applicable **generation and load change band** for more than 2 minutes while there is no *contingency event*, or be outside of the applicable *normal operating frequency band* for more than 10 minutes while there is no *contingency event*.		
6	Following a non-credible contingency event or multiple contingency event that is not a protected event, AEMO should use reasonable endeavours to: (a) maintain **system frequency** within the applicable *extreme frequency excursion tolerance limits*; and (b) avoid **system frequency** being outside of the applicable **generation** and **load change band** for more than 2 minutes while there is no *contingency event*, or being outside of the applicable *normal operating frequency band* for more than 10 minutes while there is no *contingency event.*		
7	Following a *credible contingency event* (which may be a **generation event**, a **load event** or a **network event), the rate of change of frequency** must not be greater than	...0.5Hz over any 500 millisecond period (1Hz/s)	...0.75Hz over any 250 millisecond period (3Hz/s)
8	Following a *non-credible contingency event* or **multiple contingency events** that is not a *protected event*, AEMO should use reasonable endeavours to maintain the **rate of change of frequency** within...	...0.9Hz over any 300 millisecond period (3Hz/s)	...0.9Hz measured over any 300 millisecond period (3Hz/s)
8	The size of the largest single **generation event, load event** or **network event** is limited to...	N/A	...144 MW measured ~~a) at the connection point for a generating system;~~ ~~b) at the connection point for one or more~~

	REQUIREMENT	MAINLAND	TASMANIA
			~~generating systems in an identified user group which share a dedicated connection asset.~~ This limit can be implemented for an event greater than 144MW by automatic *load shedding* or any other arrangements approved by *AEMO* that would effectively reduce the impact of the event to 144MW or below.[1] ~~in relation to any *generating system* with a capacity greater than 144 MW, or to one or more *generating systems* with a combined capacity greater than 144MW which are connected to the *transmission network* by a *single dedicated connection asset*, by automatic load shedding or any other arrangements approved by *AEMO* that would effectively reduce any **generation event** in relation to the relevant generating *system(s)* to144MW or below.~~

Note: 1. Under clause 4.8.9(a)(1) of the *Rules*, *AEMO* may require a *Registered Participant* to do any act or thing if *AEMO* is satisfied that it is necessary to do so to maintain or re-establish the *power system* to a *secure operating state*, a *satisfactory operating state* or a *reliable operating state*. Using this power, *AEMO* may direct a *Generator* to exceed the 144MW limit following a *contingency event* if *AEMO* reasonably believes this would be necessary to maintain a *reliable operating state*.

Table C.3: Summary of mainland system frequency outcomes for an interconnected system

CONDITION	CONTAINMENT BAND (HZ)	STABILISATION BAND (HZ)	RECOVERY BAND (HZ)	RATE OF CHANGE OF FREQUENCY
No *contingency event* or **load event**	49.75 – 50.25 49.85 – 50.15[1]	49.85 – 50.15 within 5 minutes		0.5Hz over any 500ms period (1Hz/s)
Generation event or **load event**	49.5 – 50.5	49.85 – 50.15 within 5 minutes		
Network event	49.0 – 51.0	49.5 – 50.5 within 1 minute	49.85 – 50.15 within 5 minutes	
Separation event	49.0 – 51.0	49.5 – 50.5 within 2 minutes	49.85 – 50.15 within 10 minutes	
Protected event	47.0 – 52.0	49.5 – 50.5 within 2 minutes	49.85 – 50.15 within 10 minutes	As per the protected event declaration
Multiple contingency event	47.0 – 52.0 (reasonable endeavours)	49.5 – 50.5 within 2 minutes (reasonable endeavours)	49.85 – 50.15 within 10 minutes (reasonable endeavours)	0.9Hz over any 300ms period (3Hz/s) (reasonable endeavours)

Note: 1. ~~99% of the time.~~System frequency must not be outside the NOFB for more than 1% of the time over any 30-day period.

Table C.4: Summary of Mainland system frequency outcomes for an island within the Mainland other than during system restoration~~s~~

CONDITION	CONTAINMENT BAND (HZ)	STABILISATION BAND (HZ)	RECOVERY BAND (HZ)	RATE OF CHANGE OF FREQUENCY
No *contingency event* or **load event**	49.5 – 50.5	N/A		0.5Hz over any 500ms period (1Hz/s)
Generation event, load event or **network event**	49.0 – 51.0	49.5 – 50.5 within 5 minutes		
The **separation event** that resulted in the **island**	49.0 – 51.0[1]	49.0 – 51.0 within 2 minutes	49.5 – 50.5 within 10 minutes	
Protected event	47.0 – 52.0	49.0 – 51.0 within 2 minutes	49.5 – 50.5 within 10 minutes	As per the protected event declaration
Multiple contingency event including a further **separation event**	47.0 – 52.0 (reasonable endeavours)	49.0 – 51.0 within 2 minutes (reasonable endeavours)	49.5 – 50.5 within 10 minutes (reasonable endeavours)	0.9Hz over any 300ms period (3Hz/s) (reasonable endeavours)

Note: 1. Or a wider band as notified to AEMO by a JSSC for a region.

Table C.5 applies in the **Mainland** during ~~supply scarcity~~system restoration if:

1. Following a *contingency event*, the *frequency* has reached the **Recovery Band** set out in Table C.3[182], and *AEMO* considers the *power system* is sufficiently secure to begin *reconnection* of *load.*
2. The estimated *load* available for *under frequency schemes* within the **island** is more than the amount required to ensure that any subsequent *frequency* excursion would not go below the **Containment Band** and **Stabilisation Band** set out in Table C.5 as a result of a subsequent **generation event**, **load event**, **network event** or a **separation event** during *reconnection* of *load.*

182 Note: In the FOS that came into effect on 1 January 2020, the Table was incorrectly listed as Table A.2.3.

3. The *generation reserve* available for *frequency* regulation is consistent with *AEMO's* current practice.

Table C.5: Summary of Mainland system frequency outcomes during ~~supply scarcity~~system restoration

CONDITION	CONTAINMENT BAND (HZ)	STABILISATION BAND (HZ)	RECOVERY BAND (HZ)	RATE OF CHANGE OF FREQUENCY
No *contingency event* or **load event**	49.5 – 50.5	N/A		0.5Hz over any 500ms period (1Hz/s) (reasonable endeavours)
Generation event, load event or **network event**	Qld and SA: 48.0 – 52.0 NSW and Vic.: 48.5 – 52.0[1]	49.0 – 51.0 within 2 minutes	49.5 – 50.5 within 10 minutes	
Protected event	47.0 – 52.0	49.0 – 51.0 within 2 minutes	49.5 – 50.5 within 10 minutes	As per the protected event declaration
Multiple contingency event or **separation event**	47.0 – 52.0 (reasonable endeavours)	49.0 – 51.0 within 2 minutes (reasonable endeavours)	49.5 – 50.5 within 10 minutes (reasonable endeavours)	0.9Hz over any 300ms period (3Hz/s) (reasonable endeavours)

Note: 1. For the operation of an **island** that incorporates *power system* elements from more than one *region*, the Containment Band for a **generation event**, a **load event** or a **network event** is the narrower of the Containment Bands for the affected *regions*. For example, following a **generation event**, **load event** or **network event** during ~~supply scarcity~~**system restoration** for an **island** that is partly within the Victoria *region* and partly within the South Australia *region*, the Containment band would be 48.5 – 52.0Hz.

The frequency outcomes for Tasmania during **system restoration** are equivalent to the requirements set out in Table A.6 for an intact *power system* and in Table A.7 for an island within the Tasmanian *power system*.

Table C.6: Summary of Tasmania system frequency outcomes where the Tasmanian power system is intact

CONDITION	CONTAINMENT BAND (HZ)	STABILISATION BAND (HZ)	RECOVERY BAND (HZ)	RATE OF CHANGE OF FREQUENCY
No *contingency event* or **load event**	49.75 – 50.25 49.85 – 50.15[1]	49.85 – 50.15 within 5 minutes		0.75Hz over any 250ms period (3Hz/s)
Generation event, load event or **network event**	48.0 – 52.0	49.85 – 50.15 within 10 minutes		
Separation event	47.0 – 55.0	48.0 – 52.0 within 2 minutes	49.85 – 50.15 within 10 minutes	
Protected event	47.0 – 55.0	48.0 – 52.0 within 2 minutes	49.85 – 50.15 within 10 minutes	As per the protected event declaration
Multiple contingency event	47.0 – 55.0 (reasonable endeavours)	48.0 – 52.0 within 2 minutes (reasonable endeavours)	49.85 – 50.15 within 10 minutes (reasonable endeavours)	0.9Hz over any 300ms period (3Hz/s) (reasonable endeavours)

Note: : 1. ~~99% of the time.~~System frequency must not be outside the NOFB for more than 1% of the time over any 30-day period.

Table C.7: Summary of Tasmania system frequency outcomes where an island is formed within Tasmania

CONDITION	CONTAINMENT BAND (HZ)	STABILISATION BAND (HZ)	RECOVERY BAND (HZ)	RATE OF CHANGE OF FREQUENCY
No *contingency event* or **load event**	49.0 – 51.0	N/A		0.75Hz over any 250ms period (3Hz/s)
Generation event, load	48.0 – 52.0	49.0 – 51.0 within 10 minutes		

CONDITION	CONTAINMENT BAND (HZ)	STABILISATION BAND (HZ)	RECOVERY BAND (HZ)	RATE OF CHANGE OF FREQUENCY
event or **network event**				
Separation event	47.0 – 55.0	48.0 – 52.0 within 2 minutes	49.0 – 51.0 within 10 minutes	
Protected event	47.0 – 55.0	48.0 – 52.0 within 2 minutes	49.0 – 51.0[1] within 10 minutes	As per the protected event declaration
Multiple contingency event	47.0 – 55.0	48.0 – 52.0 within 2 minutes (reasonable endeavours)	49.0 – 51.0 within 10 minutes	0.9Hz over any 300ms period (3Hz/s) (reasonable endeavours)

Note: ~~1. In the FOS that came into effect on 14 November 2017, the Recovery band following a protected event for an island within Tasmania was incorrectly listed as 49.85 Hz — 50.15 Hz.~~

C.3 Definitions

In this document:

- *Italicised* terms are defined in the National Electricity Rules.
- **Bold** terms are defined in Table C.8.

Table C.8: Definitions

TERM	DEFINITION
accumulated time error	For a measurement of **system frequency** that *AEMO* uses, the integral over time of the difference between 20 milliseconds and the inverse of that **system frequency**, starting from a time *published* by *AEMO*.
generation and load change band	For the **Mainland**: 1. 49.0 – 51.0 Hz for an **island** 2. during **~~supply scarcity~~system restoration:** a. 48.0 – 52.0 Hz in an island incorporating South Australia or Queensland; and b. 48.5 – 52.0 Hz in an island incorporating Victoria or New South Wales 3. 49.5 – 50.5 Hz otherwise. For **Tasmania:** 48.0 – 52.0 Hz.
generation event	1. a *synchronisation* of a *generating unit* of more than 50 MW; 2. an event that results in the sudden, unexpected and significant increase or decrease in the *generation* of one or more *generating systems* totalling more than 50MW in aggregate within no more than 30 seconds; or 3. the *disconnection* of *generation* as the result of a *credible contingency* event (not arising from a **load event**, a **network event**, a **separation event** or part of a **multiple contingency event**), in respect of either a single *generating system* or a single *dedicated connection asset* providing *connection* to one or more *generating systems*.
island	A part of the *power system* that includes *generation*, *networks* and *load*, for which all of its alternating current *network connections* with other parts of the *power system* have been *disconnected*, provided that the part: 1. does not include more than half of the combined *generation* of each of two *regions* (determined by available capacity before *disconnection*); and

TERM	DEFINITION
	2. contains at least one whole *inertia sub-network*.
island separation band	For the **Mainland**: 1. for a part of the *power system* that is not an **island**, the *operational frequency tolerance band*; 2. for an **island** that includes a part of the *power system* to which no notice under paragraph (3) applies, the *operational frequency tolerance band*; and 3. otherwise in respect of an **island**, the *frequency* band determined by the most restrictive of the high limits and low limits of *frequency* ranges outside the *operational frequency tolerance band* notified by a **JSSC** to *AEMO* with adequate notice to apply to a nominated part of the **island** within the **JSSC's** *region*. For **Tasmania**: the *extreme frequency excursion tolerance limits.*
JSSC	*Jurisdictional System Security Coordinator*
load event	For the **Mainland**: *connection* or *disconnection* of more than 50 MW of *load* not resulting from a **network event**, **generation event**, **separation event** or part of a **multiple contingency event.** For **Tasmania**: either a change of more than 20 MW of *load*, or a rapid change of flow by a *high voltage* direct current *interconnector* to or from 0 MW to start, stop or reverse its power flow, not arising from a **network event**, **generation event**, **separation event** or part of a **multiple contingency event**.
multiple contingency event	Either a *contingency event* other than a *credible contingency event*, a sequence of *credible contingency events* within 5 minutes, or a further **separation event** in an **island**.
mainland	The Queensland, New South Wales, Victoria and South Australia *regions*.
network event	A *credible contingency event* other than a **generation event**, **load event**, **separation event** or part of a **multiple contingency event**.
rate of change of frequency (RoCoF)	The change in *frequency* over a period of time (Hz/second).
separation event	A *credible contingency event* affecting a *transmission element* that results in an **island**.
system frequency	The *frequency* of the *power system*, or an **island** (as applicable).
~~supply scarcity~~system restoration	Where *load* has been *disconnected* other than in accordance with *dispatch instructions* or a *direction* or *clause 4.8.9 instruction*, or the provision of a *market ancillary service*, and not yet restored.
Tasmania	The Tasmania *region*.