RELIABILITY PANEL AEMC

REVIEW

Reliability Panel AEMC

ISSUES PAPER

REVIEW OF THE FREQUENCY OPERATING STANDARD

28 APRIL 2022

INQUIRIES

Reliability Panel
c/- Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

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

Reference: REL0084

CITATION

Reliability Panel, Review of the Frequency Operating Standard, Issues paper, 28 April 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 (Chairman), Chairman and AEMC Commissioner
Stephen Clark, Marinus Link Project Director, TasNetworks
Joel Gilmore, General Manager Energy Policy and Planning, Iberdrola Australia
Craig Memery, Director - Energy + Water Consumer's Advocacy Program, PIAC
Ken Harper, Group Manager Operational Support, AEMO
Keith Robertson, General Manager Regulatory Policy, Origin Energy
Ken Woolley, Executive Director Merchant Energy, Alinta Energy
Peter Price, Head of Corporate Strategy and Executive General Manager Asset Safety and Performance, Energy Queensland
Gabrielle Kuiper, DER Specialist - Institute for Energy Economics and Financial Analysis
Melissa Perrow, General Manager Energy, Brickworks Limited

SUMMARY

This paper initiates the Reliability Panel's review of the frequency operating standards (FOS) for the national electricity market (NEM). The standards are a key part of the frequency control arrangements, with the Panel determining the frequency requirements that AEMO must meet under different power system conditions. The Panel is investigating the appropriateness of the settings in the standard in light of the ongoing energy market transformation, as conventional synchronous generation leave the market and inverter-based technologies such as wind, solar and batteries enter the market. It is also timely to revisit the FOS given the recent regulatory reform relating to frequency.

This paper sets out issues relating to the FOS for stakeholder comment. This is the first of a series of opportunities that stakeholders will have to input on the Panel's considerations of these issues.

The FOS is a key part of the frequency control arrangements for the NEM

The FOS defines the range of allowable frequencies for the power system under different conditions. This includes during normal operation and following contingency events, such as the unexpected disconnection or failure of a large generator, load or transmission element.

The nominal - or target - for power system frequency in the NEM is 50 Hz. This frequency is essentially a measure of the speed of rotating machinery connected to the power system. When generation in the system is equal to load, the frequency will be stable. However, when the instantaneous demand for electricity exceeds the instantaneous power supplied by generators, system frequency will decrease. Similarly, frequency will increase when the level of generation exceeds the instantaneous demand for electricity in the system.

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 50 Hz. This can result in the separation of regions from the NEM, disconnection of load and — in the very worst case — the collapse of all or part of the power system, known as a black system.

AEMO is responsible for maintaining the power system within the ranges set out in the FOS. It does this by procuring frequency control ancillary services (FCAS), applying constraints to the dispatch of generation and the coordination of emergency frequency control schemes that respond to larger disturbances.

Through related elements of the Rules, the FOS also sets the performance requirements for how generators respond to frequency disturbances. This includes the frequency ranges - and times - within which generators must be able to maintain continuous uninterrupted operation. For example, during normal operation, when frequency is close to 50 Hz, generators must be capable of continuous operation for an indefinite period. When the frequency diverges further away from 50 Hz, generators are only required to be capable of continuous operation for the times set out in the FOS for the recovery of the power system following a credible contingency event.

This review will help to prepare for the future NEM

This review of the FOS is part of a broader program of regulatory reform relating to essential system services that progresses the Energy Security Board's (ESB) recommendations in the post-2025 work. This work notes that the shift to new technologies and renewable generation is happening at speed and the need for reform is urgent as we lay the foundations for Australia's new energy future. The review of the FOS is related to the frequency control element of the ESB's essential system services workstream to "strengthen the grid" and support power system security.

The drivers for this review have been identified through related work undertaken by the AEMC and AEMO. This includes the AEMC's assessment of rule changes relating to frequency control frameworks in the NEM and AEMO's *Engineering framework*, which seeks to identify the operational requirements for the future NEM.

For this review, the Panel intends to focus on the settings in the FOS that relate to the system operating conditions over the short to medium term, consistent with the outlook for AEMO's *Engineering framework*. The Panel recognises that the power system is going through a process of change that is likely to persist for decades to come. This technological change will create new challenges and opportunities for the control of system frequency. Therefore, it is expected that the FOS will need to be revisited in coming years to adapt to the changing operating conditions in the system.

This paper sets out key issues for stakeholder feedback

There are four key issues that the Panel outlines in this paper and which it would like input on. These are summarised below.

Settings in the FOS for normal operation

Recent advice from AEMO has identified a need to revise the frequency operating standards that apply during normal operation. This relates to the AEMC's assessment of enduring arrangements for Primary frequency response through the P*rimary frequency response incentive arrangements* rule change.

In March 2020, the AEMC made the *Mandatory Primary frequency response rule* 2020 to address the degradation of power system frequency performance that occurred over the period 2015 – 2020. The Mandatory PFR arrangement was introduced as an interim measure to allow AEMO and the AEMC to continue to investigate and establish enduring arrangements for effective frequency control. In September 2021, the AEMC published a draft determination and draft rule for the related P*rimary frequency response incentive arrangements* rule change, which proposed enduring arrangements of implementing incentives to complement the mandatory arrangements for PFR.

AEMO's advice, *Enduring PFR requirements for the NEM,* identified a need to review and revise the settings in the FOS that specify the target for frequency performance during normal operation. AEMO investigated a number of options to better align the settings in the FOS with the expectations for effective control of power system frequency. We are after stakeholder views on these options.

The potential inclusion of standards for RoCoF in the FOS

As the dominance of synchronous machines in the power system decreases, the level of synchronous inertia in the power system is expected to reduce. 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. Therefore, as system inertia decreases, there is an expectation that the rate of change of frequency (RoCoF) following contingency events will increase.

The FOS does not include any standard or limits with respect to system RoCoF. The Panel notes that a system standard for RoCoF would help define the requirements for the secure operation of the power system, in the context of declining levels of power system inertia. Such a limit will also inform the development of the specification and procurement systems for Fast frequency response services which help to respond to contingency events during low inertia operating conditions. We are after stakeholder views on this proposed approach.

The settings in the FOS for contingency events

An important consideration as the power system transforms is the changing nature of operational risks that must be managed to maintain the system in a secure operating state.

The settings in the FOS for contingency events provide the foundation for the operational measures taken by AEMO to maintain the system in a secure operating state such that it can be resilient to disturbances caused by unexpected equipment failures. The Panel intend to investigate opportunities to update the FOS to help manage the increasing risks to power system security identified by AEMO through the *Engineering framework* and related studies.

The Panel is considering the following issues related to the settings in the FOS for contingency events:

- The frequency bands for credible contingency events.
- The frequency bands for non-credible contingency events.
- Limits on the maximum allowable credible contingency event. This includes:
    - The existing limit of 144MW for the largest allowable generation event in the Tasmanian system
    - Whether the limit in Tasmania should be extended to apply to network and load events
    - Whether the FOS should include a limit on the maximum credible contingency event for the mainland system.

We are after stakeholder views on these areas.

The limit on accumulated 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 to have a material financial value.

In order to correct any accumulated time error, AEMO coordinates the delivery of regulating services to run the power system marginally above (or below) the nominal frequency of 50 Hz for a period of time.

In 2017, the Panel determined a revised FOS and increased the limit for accumulated time error in the mainland from 5 seconds to 15 seconds, in line with the limit for Tasmania. This review presents an opportunity to review the appropriateness of this limit and consider further revisions, to balance the benefits of limiting accumulated time error with the costs of dispatching regulation services to undertake time error correction.

The Panel's review will be guided by the national electricity objective

As well as being guided by the national electricity objective, the Panel has also set out its approach to how it will assess this review. This focuses on considering the trade-off between the costs and benefits of amending the standard. The Panel will also be informed by technical advice from AEMO.

We are after stakeholder input

Given the significance of this review, as well as the interest to date from stakeholders, there will be multiple opportunities for stakeholders to engage and participate in the process, including through bilateral meetings, public forums and formal submissions. At this stage there are two key ways to provide input:

- Written feedback: Submissions from interested parties are due by Thursday 9 June 2022.
- Informal consultation & feedback: Interested stakeholders are encouraged to contact the project leader with questions or feedback at any stage or to set up a one-on-one meeting. The project leader for this review is Ben Hiron who can be contacted on (02) 8296 7855 or ben.hiron@aemc.gov.au.

CONTENTS

APPENDICES

TABLES

FIGURES

1 INTRODUCTION

1.1 This paper explains the role and function of the FOS

Under clause 8.8.1(a)(2) of the National Electricity Rules (NER), the Reliability Panel (Panel) is responsible for determining the power system security standards, including the frequency operating standards (FOS) that apply to the National Electricity Market (NEM).[1] These standards govern the maintenance of system security and reliability in the NEM; at present, the only power system security standards that apply in the NEM are the FOS for the mainland NEM and for Tasmania. The Reliability Panel has been directed by the Australian Energy Market Commission (AEMC) to undertake a review of the FOS that apply to the NEM mainland and Tasmania.

The purpose of this paper is to explain the role and function of the FOS, to seek stakeholder comment on the content of the FOS and the Panel's proposed approach for assessing them.

1.2 The review will consider how best to define standards for frequency

The FOS define the range of allowable frequency for the power system under different conditions, including normal operation as well as after events that can impact the power system e.g. a transmission line tripping. Specifically it defines frequency bands and timeframes:

- In which the system frequency must be restored following different events, such as the failure of a transmission line or separation of a region from the rest of the NEM. These requirements then inform how AEMO operates the power system, including through applying constraints to the dispatch of generation or procuring ancillary services.
- Which are referred to by the performance standards that apply to generator and network equipment in the NEM. In combination with the FOS, these performance standards align the power system frequency managed by AEMO with the capability of NEM power system equipment, including generating and network systems.

The FOS does not set out the specific arrangements for how frequency is managed, such as the arrangements for generation and load shedding and the specification and procurement of Frequency Control Ancillary Services (FCAS). The current FOS for the NEM Mainland and Tasmania can be found on the AEMC website.[2]

1.3 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 AEMC website.[3]

1 Clause 8.8.3(a)(1) of the NER.

2 See: https://www.aemc.gov.au/australias-energy-market/market-legislation/electricity-guidelines-and-standards/frequency-0

3 Refer to the project webpage.

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.

1.4 The review will be carried out over the next 12 months

In carrying out this review, the Panel will follow a consultation process consistent with clause 8.8.3 of the NER and the Terms of Reference. The Panel will consult formally with stakeholders through seeking submissions on this issues paper and a subsequent draft report. 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 1.1.

Table 1.1: Timetable for the review

MILESTONE	PROPOSED DATA
Publish Issues Paper and Terms of Reference	28 April 2022
Public forum	May 2022
Close of submissions to the Issues paper	9 June 2022

MILESTONE	PROPOSED DATA
Receive AEMO advice	September 2022
Publish Draft Determination	November 2022
Publish Final Determination	By 7 April 2023

1.5 We encourage you to make a submission

Stakeholders can also help shape the solutions by participating in the review process. Engagement with stakeholders helps us understand the potential impacts of our decisions and, in so doing, contributes to well-informed, high quality work from the Panel.

1.5.1 How to make a written submission

Written submissions responding to this issue paper must be lodged with the Panel by 9 June 2022. All submissions received will be published on the AEMC's website (www.aemc.gov.au), subject to any claims for confidentiality.

Method of submission: Electronic submissions must be lodged online through the AEMC's website using the link entitled "lodge a submission" and reference code "REL0084". The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

If choosing to make submissions by mail, the submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. The submission may be posted to:

Reliability Panel

C/- Australian Energy Market Commission

PO Box A2449

SYDNEY SOUTH NSW 1235

1.5.2 Other opportunities for engagement

There are other opportunities for further stakeholder engagement, such as one-on-one discussions or industry briefing sessions. We are also closely collaborating with the other market bodies, most notably AEMO.

Interested stakeholders are encouraged to contact the project leader with questions or feedback at any stage. The project leader for this review is Ben Hiron who can be contacted on (02) 8296 7855 or ben.hiron@aemc.gov.au.

1.6 This paper maps out various issues for stakeholder input

The remainder of this Issues Paper is structured as follows:

- Chapter 2 — Describes the background for this review

- Chapter 3 — Sets out the approach and assessment criteria the Panel proposes to use in reviewing the FOS
- Chapter 4 — Describes the issues related to the settings in the FOS for normal operation
- Chapter 5 — Describes the issues related to the potential inclusion in the FOS of system limits for rate of change of frequency
- Chapter 6 — Describes the issues related to the settings in the FOS for the management of contingency events, including credible events, non-credible events and the consideration of limits on the maximum allowable contingency event, such as the existing limit on the maximum generation event for Tasmania.
- Chapter 7 — Describes the issues related to the settings in the FOS for accumulated time error.

This paper also includes the following appendices which provide further information related to the review:

- Appendix A — Provides an overview of the elements of the FOS
- Appendix B — Provides a general description of power system frequency and the principles for which frequency is controlled
- Appendix C — Provides an overview of the NEM frequency control frameworks.

2 BACKGROUND

This chapter sets out the background for the review. This chapter includes:

- Section 2.1 — The role of the FOS in the NEM
- Section 2.2 — Frequency performance in the NEM
- Section 2.3 — An overview of related work programs.

2.1 Overview of the FOS

The purpose of the frequency operating standards 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.

2.1.1 The FOS sets out the frequency limits within which AEMO operates the power system

The NER allows for the development of power system security standards which define the regulatory arrangements for power system security in the NEM.[4] To date, the only power system security standards are the FOS for the NEM mainland and for Tasmania.

The FOS includes settings that specify the expected frequency performance for the power system during normal operation and following credible and non-credible contingency events. Normal operation refers to the operation of the power system in the absence of any contingency event – that is, with all generators and network elements operating as expected with no unplanned outages. The FOS settings for normal operation include:

- The *normal operating frequency band* (NOFB), which is 49.85 Hz to 50.15 Hz, for the mainland and Tasmania, under normal conditions; that is, a frequency band of ± 0.15 Hz around the 50 Hz nominal frequency.
- The *normal operating frequency excursion band* (NOFEB) is 49.75 Hz to 50.25 Hz, for the mainland and Tasmania, under normal conditions; a frequency band of ± 0.25 Hz around the 50 Hz nominal frequency.
- 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 nor for more than 1% of the time over any 30-day period.

4 The power system security standards are defined in chapter 10 of the NER: "The standards (other than the reliability standard and the system restart standard) governing power system security and reliability of the power system to be approved by the Reliability Panel on the advice of AEMO, but which may include but are not limited to standards for the frequency of the power system in operation and contingency capacity reserves (including guidelines for assessing requirements).

The frequency bands defined in the FOS are also used to define the operating range for power system equipment, including generation equipment, transmission and distribution equipment and consumer equipment. The frequency requirements that form part of a generator and network performance standards are discussed in further detail in appendix C.

Using the frequency control methods described in appendix B, AEMO then operates the power system in accordance with the FOS.

2.1.2 The FOS has different settings for the mainland and Tasmania

The FOS includes different settings for the mainland NEM and for Tasmania, reflecting regional network characteristics.[5] The power system frequency is common throughout the synchronised, interconnected transmission network, as the power is transferred by way of a common alternating current waveform. This common frequency means that the impact and response to frequency disturbances is spread throughout the network and the corresponding market participants.

Currently, there are only a limited number of electrical interconnectors between the NEM regions - however more links are being considered and/or progressing. These interconnectors provide economic, security and reliability benefits by increasing the overall size of the generation pool available to supply demand and increasing the overall inertia of the interconnected power system.[6] Interconnectors create security risks of their own, especially where the number of transmission circuits is small and there is a potential for the failure of the interconnector. Such an interconnector failure may lead to the separation of the connected regions, with the smaller separated region then referred to as an "electrical island".

This is currently the case for the Heywood interconnector that provides a double circuit alternating current (AC) connection between South Australia and Victoria. When the Heywood interconnector is operating, the high levels of inertia in the broader power system assist in maintaining system security in South Australia. However, when the interconnector is affected by an outage, risks to power system security increase significantly. This is in part due to the sudden change in load immediately following the separation. In addition, high import through the Heywood interconnector at the time of the outage is likely to be correlated with fewer synchronous generating units operating in South Australia and therefore lower system inertia in that region.

The completion of Project EnergyConnect, a new 330 kilovolt (kV) double-circuit interconnector between South Australia and New South Wales, expected by July 2025, should help prevent South Australia from being 'islanded' during system stress events, which should contribute directly to a more reliable and secure system. The transmission investment will provide redundancy were the operation of the Heywood interconnector disrupted.[7] Similarly, to the existing Heywood interconnector, the Project EnergyConnect will allow for synchronous

---

5 The mainland NEM consists of the interconnected regions of Queensland, NSW, Victoria and South Australian with a combined installed generation capacity of just under 56GW.

6 AEMO, *Integrated System Plan 2020*, July 2020, p.16.

7 AEMO, *Integrated Service Plan 2022 - Draft*, December 2021, p.60.

electricity transfer, thereby providing essential system services to the region in times of high IBR generation.[8]

Tasmania and the NEM

Tasmania joined the NEM in May 2005, following the construction of the Basslink interconnector which joined the Tasmania power grid to the mainland NEM. The Basslink cable allows two-way power transfers between Tasmania and the mainland NEM using asynchronous HVDC technology, however, the Basslink frequency control strategy is designed to minimise the frequency difference thereby loosely coupling the two regions. Despite this, the regions continue to operate within the NEM as separate regions with respect to power system frequency.

The Tasmanian power system differs significantly from that of the NEM mainland in that it is relatively small in overall generation size, has relatively large load, generator and network contingencies as a proportion of total system size and is predominantly supplied by hydroelectric plants with relatively slow reaction times to frequency disturbances. Tasmania may also experience times of relatively low inertia at times of high IBR generation or import through Basslink.

Due to these characteristics, frequency control within narrow tolerances is relatively difficult in Tasmania; however the dominance of hydro generation and its ability to withstand wider frequency deviations has meant that historically this situation has been a non-issue.[9]

The construction of an additional HVDC connection between Tasmania and the mainland NEM is being considered as part of the Marinus Link project. The proposed 1500 MW interconnector — delivered through two 750 MW cables — would further link Tasmania as part of mainland's electricity grid.[10] TasNetworks has estimated that the earliest full commissioning of the first cable is expected by July 2029 and the second cable by July 2031.[11] Similarly to Basslink, the proposed Marinus Link project would allow for two-way power transfers through an asynchronous DC connection meaning that the frequency separation between Tasmania and the mainland will be maintained.

2.2 Frequency performance in the NEM

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

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

8 FTI Consulting, *Benefits of Project EnergyConnect - Final Report,* June 2020.

9 State of Tasmania, Electricity Supply Industry Expert Panel, Technical Parameters of the Tasmanian Electricity Supply System, 2001, p.24.

10 AEMO, *Draft 2022 Integrated System Plan*, December 2021, p.61

11 TasNetworks, *Submission to the Draft 2022 Integrated System Plan*, February 2022.

2.2.1 Frequency performance has improved following the introduction of mandatory PFR

Power system frequency performance in the NEM during normal operation degraded significantly over the period 2015 – 2020. 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, 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 are currently being considered through the *primary frequency response incentives* rule change. Box 1 provides an overview of PFR.

BOX 1: WHAT IS PRIMARY FREQUENCY RESPONSE?

Primary frequency response (PFR) provides the initial response to frequency disturbances caused by power supply-demand imbalances. It reacts automatically and almost instantaneously to locally measured changes in system frequency outside predetermined set points. PFR involves an automatic change in active power generated (or consumed) by a generator (or load) in response to a locally measured change in system frequency.

In order to provide PFR, a generator must operate its plant in a 'frequency response mode' which is defined in chapter 10 of the Rules as: "the mode of operation of a generating unit which allows automatic changes to the generated power when the frequency of the power system changes."

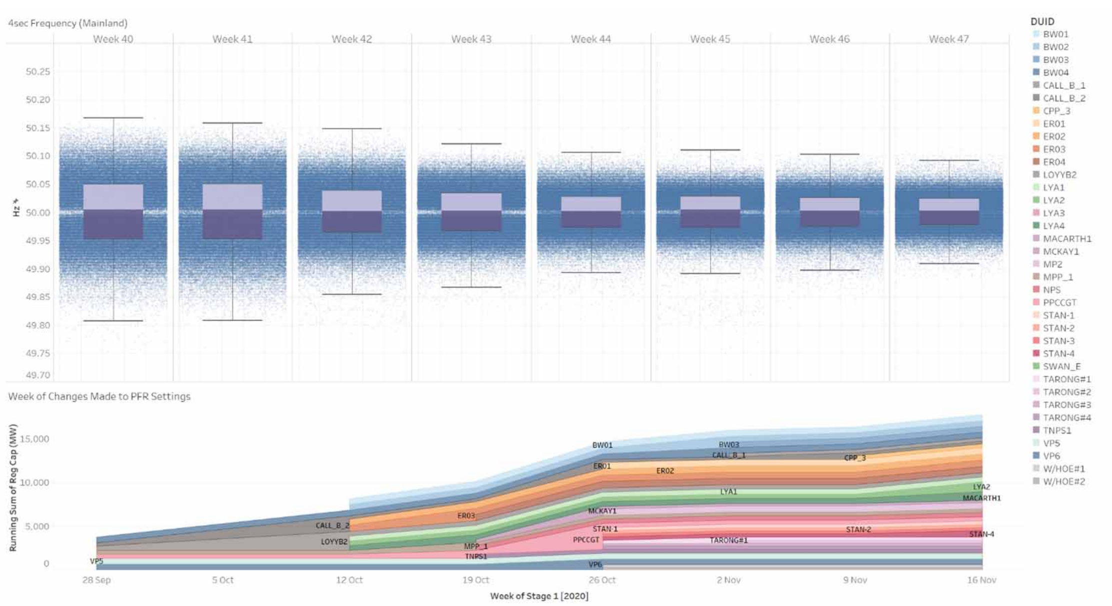
The key attributes of PFR are that it is:

- **Locally responding** — responds to locally measured frequency and, hence, is not subject to centralised control, communications delays and time synchronisation issues.
- **Fast acting** — provides an immediate action to respond to frequency deviations.
- **Automatic** — responds automatically to adjust generation output to arrest and stabilise frequency, typically in proportion to measured frequency deviation outside predetermined set points.

PFR is a distinctly different service from secondary frequency response. PFR provides fast control action that responds rapidly to contain frequency deviations, while secondary frequency response is a slower control action that acts to relieve PFR providers and to help rebalance energy supply and demand until generation dispatch can be adjusted.

In September 2020, AEMO commenced the coordination of changes to generator control systems in accordance with the Mandatory PFR rule.[12] This resulted in a significant increase in the quantity of generation plant that are responsive to small changes in power system frequency either side of 50 Hz. While implementation of changes to generator control systems is ongoing, the majority of changes to affected plant were activated during the period October 2020 to November 2021 as shown in Figure 2.1. This change to generator control settings had a marked impact on the distribution of power system frequency.

Figure 2.1: Impact of Mandatory PFR implementation on frequency distribution



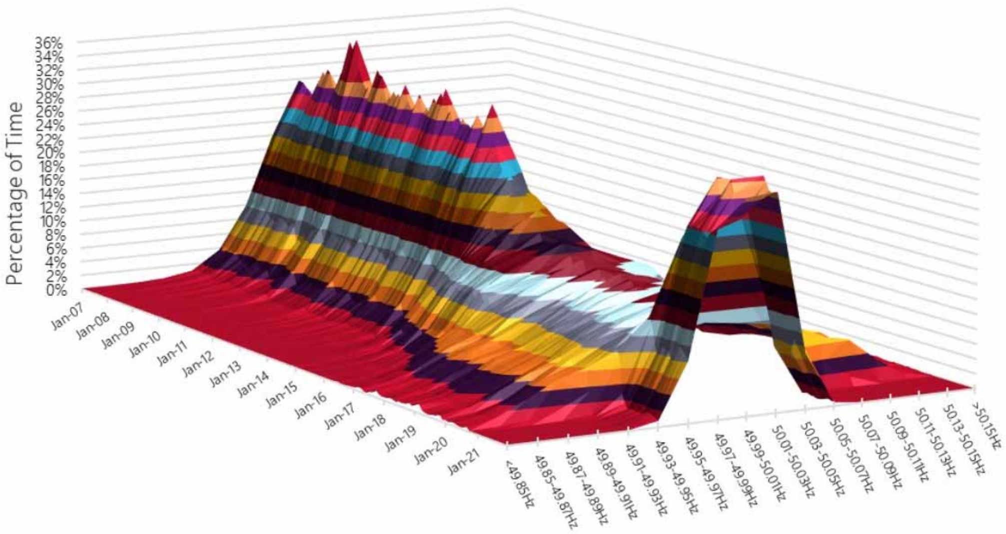
Source: Greenview consulting analysis prepared for the AEMC based on publicly available data from AEMO (Ancillary services market Causer pays data, PFR Implementation reports)

Note: As of 20 January 2022, AEMO had commenced or completed the implementation of control system changes for 40.2 GW out of a potential 57.6 GW of generation plant capacity. Ref: AEMO, Implementation of the National Electricity Amendment (Mandatory Primary Frequency Response) Rule 2020, Status as at 20 Jan 2022, 21 January 2022.

Figure 2.2 illustrates the much-improved control over power system frequency following the implementation of mandatory primary frequency response.

12 National Electricity Amendment (Mandatory primary frequency response) Rule 2020.

Figure 2.2: Monthly mainland frequency distribution



Source: AEMO, *Frequency and Time Error Monitoring — Q4 2021*, February 2022, p.6.

The implementation of mandatory PFR from late 2020 lead to a significant improvement in power system frequency performance during normal operation. AEMO noted in its 2021 PFR technical white paper that:[13]

> The AEMC's 2020 mandatory PFR (MPFR) rule [has] re-established effective frequency control within the normal operating frequency band (NOFB) in the NEM through the introduction of:
>
> - Tightly managed control – narrow deadband frequency responsiveness from generators including inverter-based resources (IBR) as part of the MPFR roll out, starting from no more than 15 millihertz (mHz) away from the nominal 50 hertz (Hz) frequency.
> - Widespread response – near-universal, mandatory requirement across all scheduled and semi-scheduled generation, including IBR, and agnostic to technology.

AEMO also noted that there was now an opportunity to review the settings in the FOS for normal operation to better specify the requirement for system frequency control within the normal operating frequency band.

Through this review, the Panel will consider the settings in the FOS for normal operation, including the PFCB, further detail on this issue is included in chapter 4.

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

2.2.2 Recent frequency performance in the mainland and Tasmania

In its recent frequency and time error monitoring report for Q4 2021, AEMO noted that:[14]

> 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.

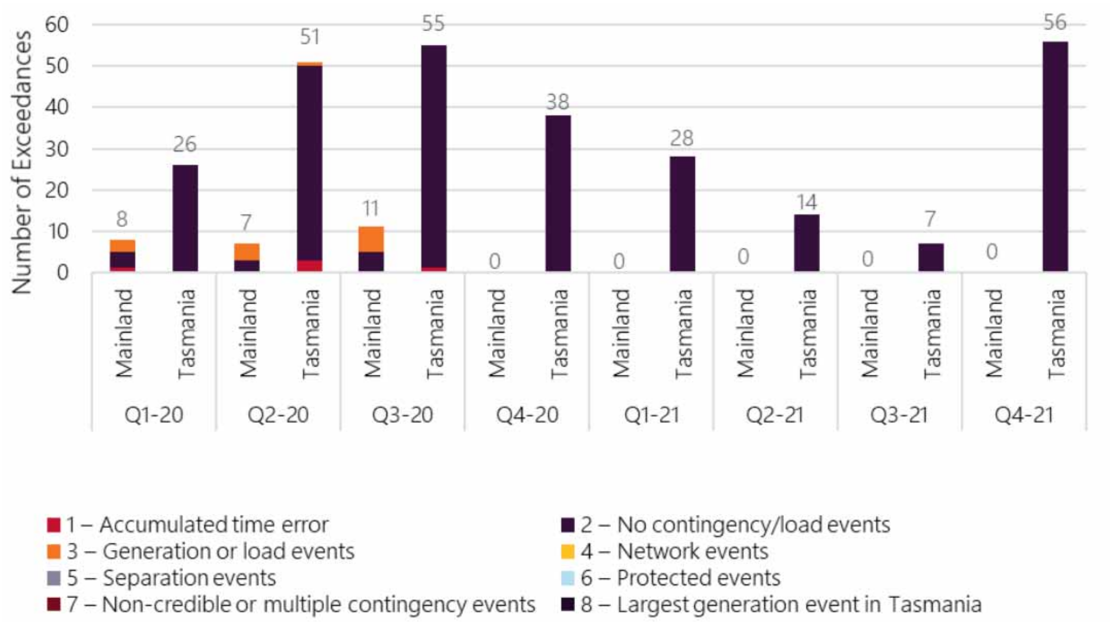
The number of excursions outside of the FOS requirements in the mainland has also reduced in recent times, folloing the introduction of mandatory PFR, as shows in Figure 2.3. AEMO noted that:[15]

> It is apparent that the implementation of Mandatory PFR rule has contributed to reducing:
>
> - The number of FOS exceedances following generation or load events, by increasing the available dynamic system frequency response to sudden and significant supply and demand imbalances.
> - The number of FOS exceedances during periods without an identified contingency, by reducing the likelihood of frequency being near the NOFB boundaries and subsequently straying beyond the NOFB, while also increasing the available restorative response to such events should they occur.

14 AEMO, *Frequency and Time Error Monitoring — Q4 2021*, February 2022, pp.12-13.

15 Ibid., p.8.

Figure 2.3: FOS exceedances in the mainland and Tasmania



Source: AEMO, *Frequency and Time Error Monitoring — Q4 2021, February 2022,* p.8.

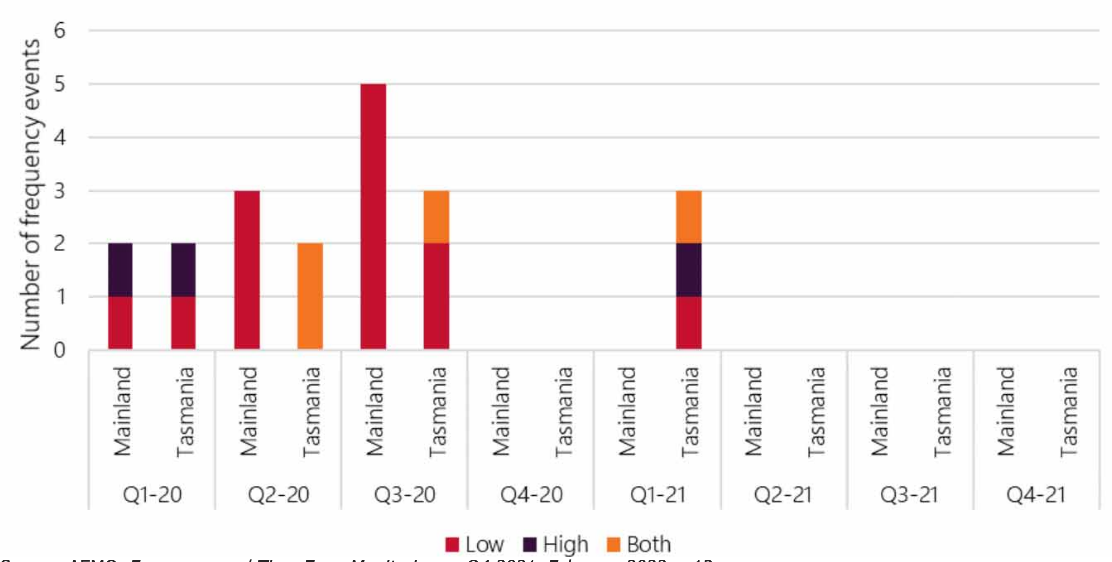
Frequency excursions without a contingency event

According to AEMO, the implementation of the mandatory PFR rule is considered to have reduced the likelihood of frequency being near the NOFB boundaries, making it less likely that frequency strays beyond the NOFB without a contingency event.

Figure 2.4 shows, for Q4 2021, the number of frequency excursions outside the applicable NOFB and not recovered in time for which contingency events have not been identified. The figure illustrates the improvement from Q3 2020.[16]

16 Ibid., p.12.

Figure 2.4: Frequency excursions without identified contingency outside the NOFB and not recovered in the FOS timeframe in the mainland and Tasmania

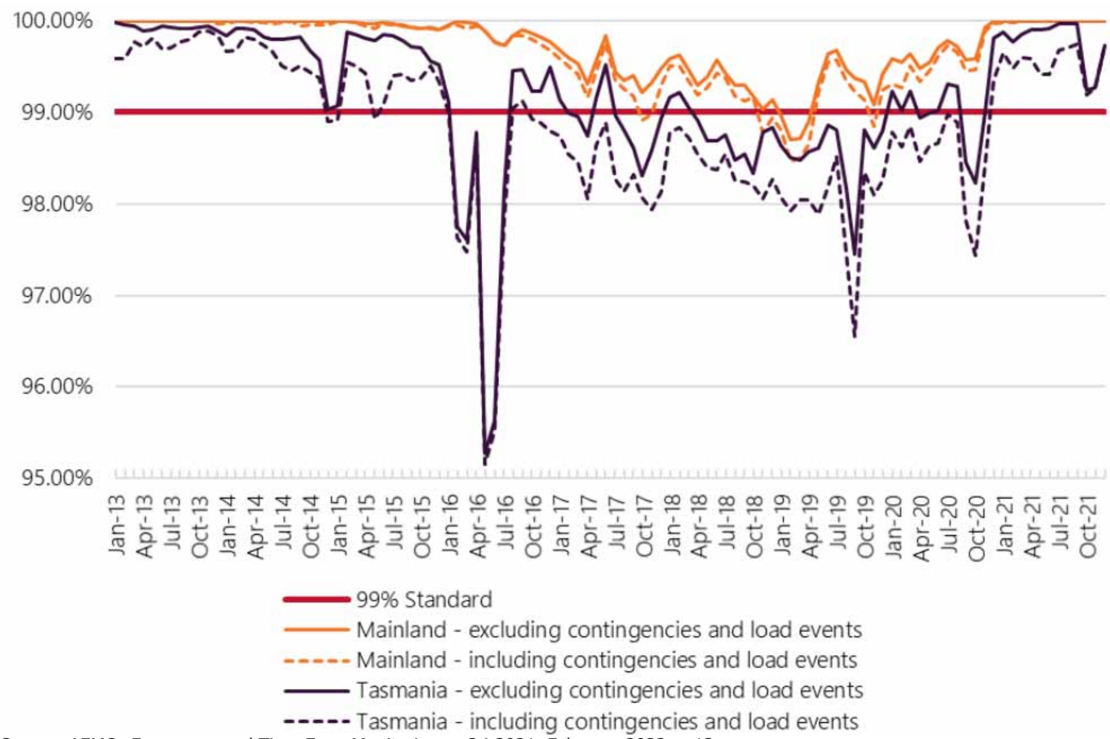


Source: AEMO, *Frequency and Time Error Monitoring — Q4 2021, February 2022,* p.12.

Frequency performance within the NOFB

Figure 2.5 shows that the frequency in the mainland and Tasmania remained within the NOFB for more than 99% of the time in Q4 2021. 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.

Figure 2.5: **Frequency in NOFB since January 2013, minimum daily time percentage in prior 30-day window**

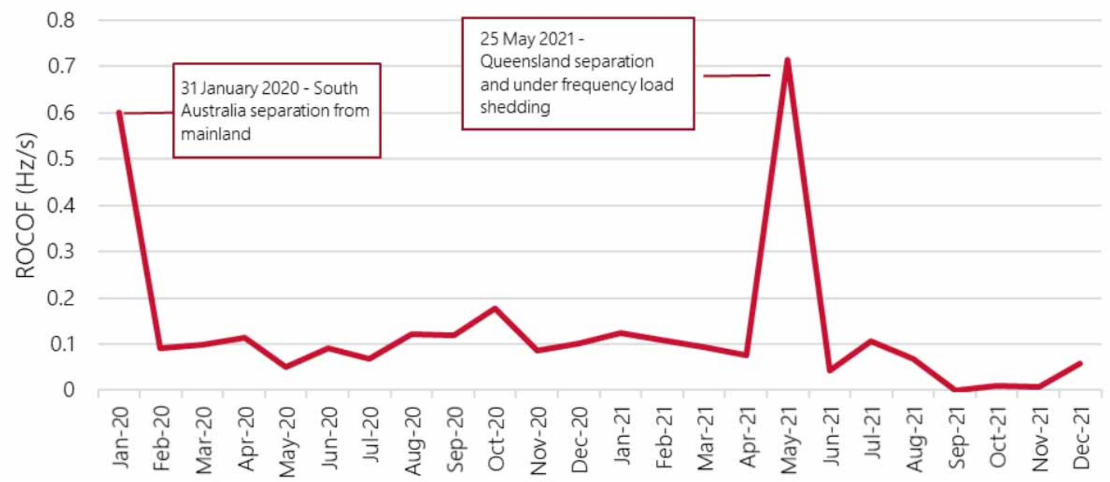


Source: AEMO, *Frequency and Time Error Monitoring* — Q4 2021, February 2022, p.13.

Maximum RoCoF in the mainland NEM

Figure 2.6 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.

Figure 2.6: Monthly maximum RoCoF recorded in any mainland region in 2020 and 2021



Source: AEMO, *Frequency and Time Error Monitoring — Q4 2021, February 2022,* p.19.
Note: 25 May 2021 RoCoF as measured in Queensland and 31 January 2020 RoCoF as measured in South Australia

2.3 The Panel's work will dovetail with other work completed or currently being undertaken

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

- AEMO's *Engineering Framework*. 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 the Panel's review of the FOS are outlined throughout this Issues paper.

- AEMO's review of the MASS — FFR specification. AEMO is shortly to undertake 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.[17] The AEMC is currently considering how best to create enduring arrangements that incentivise primary frequency response to complement the mandatory primary frequency response arrangements. A draft determination on this was published in September 2021, and a final determination is currently scheduled for July 2022.

  The Panel understands that the rule change will confirm the mandatory PFR requirements for market participants. The standards 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*.[18] 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 is due for this rule change in June 2022.

  The proposed RoCoF standard and the requirements for frequency performance during normal operation, being considered as part of this review, may guide AEMO's procurement of secure configurations of units through the operational security mechanism.

- The AEMC's assessment of the *Efficient provision of inertia rule change*.[19] 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 consideration of a RoCoF standard could guide AEMO on the procurement of inertia through a potential market ancillary service.

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

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

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

3 APPROACH AND ASSESSMENT CRITERIA

This chapter sets out the Panel's approach and assessment criteria, including:

- Section 3.1 — the Panel's objective in undertaking its assessment
- Section 3.2 — the Panel's proposed approach to the review
- Section 3.3 — the proposed assessment criteria relevant to the review
- Section 3.4 — AEMO advice provided to the Panel.

3.1 The Panel will be guided by the NEO

In undertaking the Review of the FOS, the Panel will be guided by the national electricity objective (NEO) which is set out under section 7 of the National Electricity Law (NEL).

The NEO is:

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

The Panel considers that the relevant aspects of the NEO for its review of the FOS are the operation of electricity services, with particular respect to the safety and security of the national electricity system and the price, quality and security of supply of electricity.

3.2 The Panel will consider the trade-offs between benefits and costs

In undertaking its review, the Panel will seek to strike an appropriate balance between providing improved quality and security outcomes against the cost of delivering those outcomes.[20] This is because while changes to make the FOS more stringent (such as narrowing the various bands within which the frequency must be maintained) may provide benefits to consumers by delivering enhanced power quality and system security, this may also impose additional costs on market participants which are ultimately borne by consumers.

These FOS-related quality and security benefits and associated costs may arise in a number of ways. At a high level, some of the potential benefits of a more stringent FOS may include the following:

- The FOS may be "tightened" so that the system frequency is required to be closer to the nominal frequency of 50 Hz. This could result in improved system security as a result of the increasing the time that the power system frequency is maintained close to the

20 In this sense the term "quality" refers to electrical power quality which is a measure of the uniformity of the voltage waveform which describes the fluctuating system voltage and the associated frequency. A high level of power quality relates to a stable system voltage at a steady frequency where the power system is resilient to contingency events. A low level of power quality occurs when the system voltage and frequency fluctuate more widely in response to destabilising events.

nominal frequency of 50 Hz and away from the load shedding band and extreme frequency tolerance limits.[21] If the power system frequency is further away from 50 Hz when a contingency event occurs, the resulting frequency deviation may be more severe. This could in turn lead to an increased likelihood of load shedding and potentially a cascading outage and black system. The associated benefit of a narrower standard is the avoidance of the costs of unserved energy due to load shedding.

- A more stringent FOS could also deliver improved power quality through supporting a more uniform and stable power system frequency. Such a quality improvement may deliver benefits through reducing the operation and maintenance costs of generation equipment. This reduced operation cost is a product of potential reductions in maintenance costs and improvements in generator fuel efficiency through maintaining the power system frequency close to 50 Hz.[22]

However, costs associated with tightening elements of the FOS may also include:

- Increased expense of procuring FCAS to meet the FOS. Maintaining system frequency within narrower operating bands may require more FCAS to be procured by AEMO, potentially increasing the total costs of regulation and contingency FCAS. This cost is borne by market participants and ultimately consumers through higher electricity prices.
- There is a potential that a more stringent FOS could create a barrier to the use of all possible technologies in the NEM, if certain technologies are unable comply with the technical standards that are dependent on the FOS. To the extent that this impedes participants from using all available technologies to participate in the NEM, this could preclude the use of the lowest cost technologies to meet consumer demand, reducing the efficiency of dispatch and potentially placing upwards pressure on wholesale market costs.
- Tightening the operational frequency tolerance band in the FOS would bring forward the trigger limit for load shedding and potentially have the effect of increasing the relative likelihood of load shedding occurring. This may increase costs related to unserved energy associated with load shedding.[23]

The complexity of optimising the FOS is also related to the fact that while changing any specific component of the FOS may change system security outcomes, it is also likely to impose costs on various participants through meeting more strenuous obligations, or on AEMO through a requirement to procure additional ancillary services or constrain dispatch. The setting of each component of the FOS, therefore, needs to be considered in terms of the balance between these security benefits and costs.

21 The issue of the relationship between improved system security and a tightened FOS was mentioned in the Finkel panel report into the NEM. Commonwealth of Australia, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, 2017, p.58.

22 Historically, synchronous generation equipment has been finely tuned to operate at peak efficiency when the system frequency is close to the nominal value. As the frequency moves away from this value, generators operate less efficiently which may result in increased fuel usage and increased wear and tear on units.

23 The Panel notes that tightening the operational frequency tolerance band may also provide some benefits in this regard, as it would result in an under-frequency load shedding scheme having a wider frequency window of operation, which may decrease the risk of a black system event.

For example, widening the extreme frequency excursion limit may superficially reduce the costs of managing the system, as it would allow AEMO to operate the system over a greater frequency range and therefore reduce the costs associated with procuring ancillary services or constraining dispatch. However, operating the system in such a way could also increase the risk of some equipment being unable to function effectively and could also increase the risk of damage to generation plant or be a barrier to entry for some frequency sensitive generation. Changing the frequency bands may also incur significant implementation costs for both AEMO and network and generation assets, as the plant settings related to frequency would need to be adjusted and retuned.

Similarly, the length of the frequency restoration timeframes must be considered in terms of security benefits and cost. Extending the recovery time (currently ten minutes) might potentially reduce the cost of managing the system but may also have significant security implications, as it may increase the risk of a cascading failure and potentially a black system as a result of subsequent contingency events.[24]

3.3 The Panel will consider the following criteria when assessing options

In its assessment of any changes to the components of the FOS and consistent with satisfying the relevant aspects of the NEO outlined above, the Panel will therefore give consideration to the following principles:

- **Promoting power system security:** the power system can be considered to be in a satisfactory operating state when it is operated within specified technical operating limits, including voltage and other stability limits. 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 will consider 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 will consider how the specification of settings of the FOS will likely spread 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,

24 A longer restoration time may increase the likelihood of a subsequent generator contingency (trip) as a result of the generator's decreased resilience to prolonged frequency deviations.

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 will consider how the settings of the FOS are 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. 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.

Ultimately, the Panel's responsibility in determining the FOS is to identify a reasonable, effective and efficient trade-off between the security benefits of a more stringent FOS, against the costs that this would impose on consumers. While it is essential that minimum limits of security and safety are maintained, this should occur at the lowest possible cost for consumers. Furthermore, the Panel will consider whether additional security benefits above this basic, minimum level are warranted, given the incremental costs of providing that additional security. These trade-offs will therefore be central to the Panel's consideration as part of this review.

3.4 The Panel will seek formal 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".[25] Therefore, in addition to consulting with key stakeholders, the Panel will seek formal advice from AEMO to support its review and determination of the FOS.

The Panel expects that the AEMO advice will cover the scope of issues identified in this consultation paper, along with other relevant issues identified through the consultation process and by AEMO. The Panel will publish a copy of AEMO's advice as a companion to its draft determination.

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

4 FREQUENCY PERFORMANCE DURING NORMAL OPERATION

The FOS sets out the frequency limits within which AEMO operates the power system. This includes defined frequency bands and time frames in which the system frequency must be restored following different events, such as the failure of a transmission line or separation of a region from the rest of the NEM.

During normal operation AEMO must maintain the power system frequency within the range of 49.85 – 50.15 Hz for at least 99% of the time. During normal operation the frequency may exceed the NOFB for brief periods that do not exceed 5 minutes on any occasion and not for more than 1% of the time over any 30-day period. In such circumstances, frequency must be maintained with the NOFEB (49.75 Hz – 50.25 Hz).[26]

While frequency performance during normal operation has improved since the implementation of Mandatory primary frequency response (PFR), the Panel understands that an opportunity exists to amend the FOS to better specify the requirement for frequency performance within the boundaries of the NOFB. As AEMO noted in its 2021 PFR technical white paper:[27]

> While the FOS currently includes a number of criteria relating to frequency performance, including defining the boundaries for performance under normal operating conditions (the NOFB), it does not currently define acceptable frequency performance within these boundaries.
>
> There is an opportunity to amend the FOS to better specify frequency performance requirements under normal conditions. This will help the effectiveness of PFR frameworks over time to be understood and evaluated, benchmarked against actual frequency performance. This will be increasingly important as the power system transitions and new operational conditions emerge over time.

The Mandatory PFR rule 2020 also introduced the concept of a Primary frequency control band (PFCB) which sets a lower bound for the maximum allowable deadband that AEMO specifies for affected generators in its Primary Frequency Response Requirements. The PFCB is defined in the NER as:[28]

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

Due to its role in guiding the specification for mandatory PFR, the PFCB is directly related to the settings in the FOS for normal operation

26 See: https://www.aemc.gov.au/australias-energy-market/market-legislation/electricity-guidelines-and-standards/frequency-0

27 AEMO, *Enduring PFR requirements for the NEM - Technical white paper*, August 2021.

28 Chapter 10 definition.

This chapter describes and discusses the settings in the FOS related to frequency performance during normal operation and sets out the Panel's initial considerations, including:

- Section 4.1 — The existing settings in the FOS for normal operations
- Section 4.2 — Potential changes to the requirements in the FOS for normal operations
- Section 4.2.4 — Consideration of the primary frequency control band for normal operations.

4.1 The existing standards for normal operation

AEMO recognises, despite the improvement in frequency operation following the introduction of mandatory PFR, that the settings in the FOS for normal operation could be revised to better reflect the target for system frequency during normal operation.[29] This could include:

- Revision of the existing settings, including the NOFB, the NOFEB and the requirement to stay within the NOFB 99% of the time.
- The potential for specification of additional detail in relation to the target for system frequency during normal operation, such as additional qualitative criteria or additional frequency control bands, consistent with AEMO's *Enduring primary frequency response requirements for the NEM* white paper.
- Inclusion of a PFCB, as specified in the NER through the mandatory PFR rule. The PFCB sets the inner limit beyond which AEMO may define the allowable mandatory PFR deadband.

The Panel will consider these through the course of the review.

4.2 The requirements for frequency performance during normal operation

The Panel recognises that there is an opportunity to redefine and improve the way the FOS specifies the requirement for frequency performance during normal operation. A change to this element of the FOS has been proposed by AEMO in its 2021 PFR technical white paper and has been proposed in stakeholder submissions to the AEMC consultation on the PFR incentive arrangements rule change, as discussed below.

4.2.1 AEMO's proposed change to the FOS for normal operation

In September 2021, AEMO provided expert technical advice to the AEMC on the system requirements for PFR to inform the Commission's decision on enduring arrangements for PFR. In its advice, AEMO notes that the implementation of near universal (mandatory) narrow band frequency response has re-established stable frequency control in the NEM and realigned the operating practices with comparable international power systems. AEMO considers that PFR is not a service, but rather a parameter (aggregate frequency responsiveness) that must be maintained. As such, AEMO recommends that the technical

29 AEMO, *Enduring PFR requirements for the NEM - Technical white paper*, August 2021

outcomes of the mandatory PFR arrangements (tightly managed control with widespread response) be preserved in any future arrangements.[30] The AEMC made a draft determination for the primary frequency response arrangements rule change which made a draft ruling that these arrangements should be continued but should be complemented by incentives.

AEMO's rationale for the continuation of the technical outcomes derived from the existing mandatory narrow-band PFR arrangements can be summarised as:[31]

- Effective PFR is essential for robust power system frequency control. PFR is an integral part of an integrated chain of control actions. Near universal narrow band frequency response improves the effectiveness of other elements of the broader frequency control framework and increases the predictability of generating system response to disturbances. This provides a sound control base for system operation and supports AEMO's analysis and modelling of power system performance which feeds the design of system, control, and protection arrangements.
- Effective, tight control of frequency is a necessity today and will be more so in the transition towards a power system that is increasingly dependent on variable and inverter-based generation. AEMO acknowledges that there are expected to be future operating conditions where large scale centralised generation is increasingly displaced by variable renewable generation and distributed rooftop solar power, which provide limited or no PFR. During these future operating conditions, the level of PFR provided by generating resources under the mandatory arrangements may reduce. Additional arrangements may be required to deliver sufficient levels of frequency responsiveness to control power system frequency.

AEMO examined different options to amend the FOS to explicitly specify acceptable performance within the NOFB, including the explicit definition of a NOPFB within the FOS with adequacy benchmarked through actual frequency performance over any 30-day period.

AEMO undertook an analysis of four different options to amend the FOS to better specify frequency performance requirements during normal operation, and enable frequency outcomes to be tracked against requirements over time.[32]

A summary of these options and AEMO's related recommendations are summarised in Table 4.1 below.

Table 4.1: **Summary of different FOS amendment options and AEMO's recommendations**

OPTION	RECOMMENDATION	REASONS
Option 1: Introduce qualitative criteria	Not recommended	Does not provide any defined metric or benchmark that could be used to track frequency performance.
Option 2: Introduce	Recommended option	Transparent and aligned with current FOS

30 Ibid., pp.3-18.

31 Ibid., pp.32-34.

32 Ibid., pp.25-28.

OPTION	RECOMMENDATION	REASONS
additional frequency band		descriptions and implementation.
Option 3: Introduce standard deviation benchmark	Not recommended	Calculated benchmark gives similar outcomes to Option 2, however is not aligned with current FOS descriptions, is computationally difficult, and requires benchmark to be retuned over time.
Option 4: mileage measure and benchmark	Not recommended	Benefits unclear. Further work needed to understand whether benchmarks are necessary and how these benchmarks should be determined.

Source: AEMO, *Enduring PFR requirements for the NEM — White Paper*, August 2021, p.28.

AEMO Option 1 - Qualitative criteria

AEMO's option 1 is for amendment of the FOS for normal operation to introduce qualitative objectives or criteria within the FOS pertaining to frequency performance under normal conditions. AEMO does not consider this to be the preferred option because implementation or evaluation of frequency performance would be subjective without a defined trackable metric and any established benchmark or criteria for acceptable performance.[33]

AEMO Option 2 - Additional frequency band

AEMO's option 2, as shown in Figure 4.1, would introduce a new frequency band to the FOS within the NOFB. AEMO proposed that:

- This new band, the normal operating primary frequency band (NOPFB), be initially set at 49.95 Hz – 50.05 Hz, for the mainland and Tasmania, under normal conditions.
- Except as a result of a contingency event or load event, system frequency shall not be outside of the applicable NOPFB for more than 10% of the time for the mainland and 15% of the time for Tasmania over any 30-day period.

AEMO's recommended option 2 is its preferred option due to the practicality of implementation and the clarity of the related benchmark. It provides a transparent metric and assessment benchmark, consistent with the current FOS requirements.[34]

33 Ibid., p.59.

34 Ibid., pp.59-61.

Figure 4.1: Frequency in NOPFB (±0.05Hz) since 2007, minimum daily time percentage in prior 30-day window

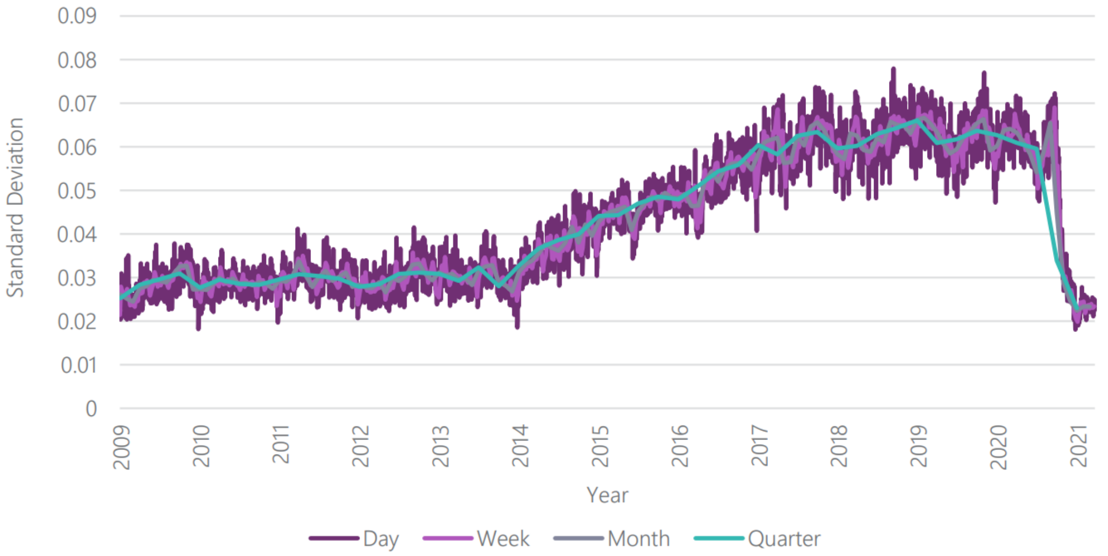
Source: AEMO, *Enduring PFR requirements for the NEM — Technical white paper*, August 2021, p.61.

AEMO Option 3 - Standard deviation benchmark

Option 3, shown in Figure 4.2, considered the introduction of a standard deviation benchmark to describe acceptable frequency performance during normal operation. The effectiveness of the metric was shown to be similar to option 2, however, AEMO considered it not to be aligned with current FOS specifications and assessed that it would require the benchmark to be retuned over time.[35]

35 Ibid., pp.61-61

Figure 4.2: Historic frequency standard deviation



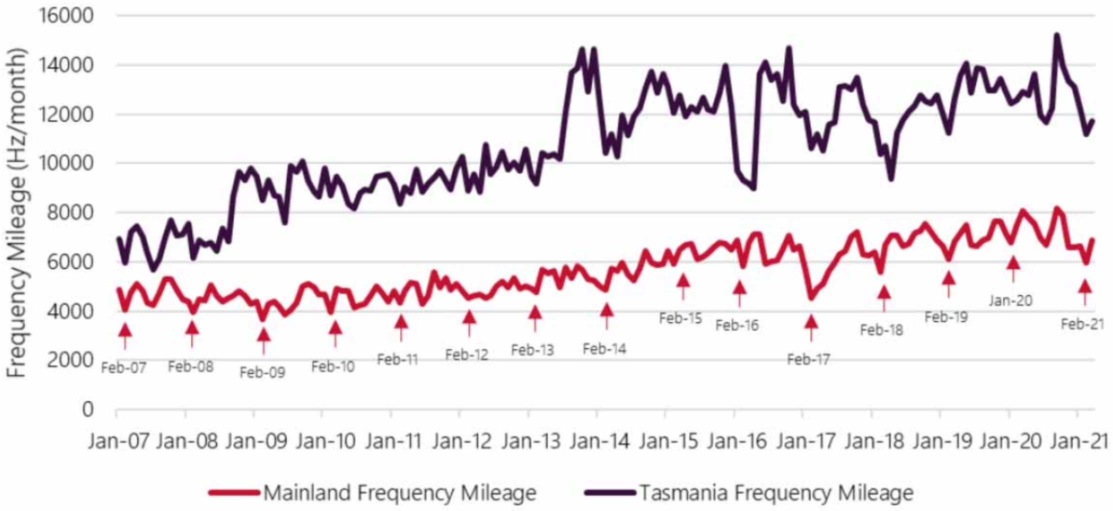
Source: AEMO, *Enduring PFR requirements for the NEM — Technical white paper*, August 2021, p.62.

AEMO Option 4 - Frequency mileage measure and benchmark

Option 4, illustrated in Figure 4.3, would introduce a frequency mileage measure and associated benchmark for frequency performance under normal operation. Frequency mileage is a measure of the stability of power system frequency. It is calculated by summing the absolute changes in frequency from one interval to the next over a given period; that is a more stable frequency will see a lower mileage and vice versa. AEMO tracks this metric on a monthly basis as part of its quarterly frequency performance reporting. AEMO concluded that additional consideration is needed to better understand the relevance of mileage in the context of acceptable frequency performance before it can be recommended.[36]

36 Ibid., p.66.

Figure 4.3: Monthly frequency mileage in the NEM since 2007



Source: AEMO, *Enduring PFR requirements for the NEM — Technical white paper*, August 2021, p.67.

4.2.2 Stakeholder views

The Panel is aware of stakeholder support for a review of the settings in the FOS for normal operation. These views have been expressed through submissions to the AEMC *PFR incentive arrangements* rule change and by way of direct correspondence to the Panel.

Stakeholder submissions to the *PFR incentive arrangements* rule change

Through the consultation on the *PFR incentive arrangements* rule changes, a number of stakeholders expressed the view that the arrangements for Primary frequency response in the NEM should be guided by the system requirement for frequency performance during normal operation as defined in the FOS. While recognising that frequency performance in the NEM had degraded during the period 2015-2020, these stakeholders considered that a fundamental step toward addressing this issue was for the Reliability Panel to review the FOS to determine appropriate targets for frequency performance during normal operation.[37]

AEC letter to the Panel

On 2 July 2020, the Chair of the Reliability Panel received a letter from the Australian Energy Council (AEC) requesting that the Panel review the settings in the FOS for frequency performance during normal operation.

The AEC noted the important role that the Panel plays in setting clear performance targets for the NEM, while balancing out the implications for power system security and the related operational costs. It expressed the view that the Mandatory primary frequency response rule,

37 See example submissions to the December 2020 Frequency control rule changes Directions Paper from AEC (pp.7-10), AGL (p.9), Alinta Energy (p.8.), CEC (p.3.), CS Energy (pp.16-18.), Delta Electricity (p.19.), Energy Australia (p.2), Engie (p.7) and NEOEN (p.2.).

made by the AEMC on 26 March 2020, established an operational outcome that exceeded the requirements in the FOS for frequency performance during normal operation. In that context, the AEC requested that the Panel review and determine a new standard for frequency performance during normal operation, reflecting the security advantages of a tighter outcome against the costs associated with meeting it. [38]

AEMO subsequently provided technical advice to the AEMC clarifying its expectations for aggregate frequency responsiveness and the performance of power system frequency during normal operation. The aspects of this advice that relate to the FOS are described in section 4.2.1.

4.2.3 Panel Commentary

The Panel acknowledges the views expressed by stakeholder submissions to the AEMC's consultation on the *PFR incentive arrangements* rule change, and the letter from the AEC, that the settings in the FOS for normal operation should be reviewed to be consistent with the frequency performance achieved as a consequence of the universal provision of mandatory narrow band PFR. This review provides an opportunity to review the settings in the FOS that specify the target for frequency performance during normal operation and the Primary frequency control band (PFCB), which relates to the settings for the provision of mandatory PFR. Further discussion of the potential to define the PFCB in the FOS is included in section 4.2.4.

AEMO's *Technical white paper - Enduring PFR requirements for the NEM*, also noted that the specification of the target for frequency performance during normal operation could be more explicitly defined in the FOS.[39] AEMO identified four potential options to improve the specification of frequency performance during normal operation as summarised below:

1. Introduce qualitative criteria
2. Introduce an additional frequency band within the NOFB - the NOPFB
3. Introduce a new requirement based on the standard deviation of power system frequency during normal operation
4. Introduce a requirement based on the mileage of power system frequency.

The Panel notes an additional option for consideration: the narrowing of the existing NOFB. This option would be similar in application to option 2, in that the target for system frequency during normal operation would be clearly defined. However, it would not require the creation of an additional frequency band in the FOS.

In the *Frequency and Time Error* monitoring report for *Q3 2021*, AEMO reported a pattern of occurrences where the system frequency exceeded the Normal operating frequency excursion band (49.75Hz - 50.25Hz) in Tasmania in the absence of a contingency event. In the context of this AEMO stated that:[40]

38 AEC, *Normal Operating Band Frequency Operating Standard - Letter*, 2 July 2020, available at: https://www.energycouncil.com.au/media/153d0zbl/panel-letter-to-aec-future-review-of-the-fos-6-october-2020.pdf

39 AEMO, *Enduring PFR requirements for the NEM - Technical white paper*, August 2021

40 AEMO, *Frequency and Time Error Monitoring Q3 2021,* February 2022, p. 11.

> Under system normal conditions, the FOS specifies largely the same requirements for Tasmania as it does for the mainland. However, as a much smaller system, Tasmania is more sensitive to supply/demand imbalances which manifest as larger frequency deviations

AEMO noted that it intends to monitor and adjust control settings in the Tasmanian region as required. At the same time, the Panel notes that it may be appropriate to review the target for frequency performance during normal operation in the Tasmanian region, including whether it continues to be appropriate for the settings in the FOS for Tasmania to align with those for the mainland, despite the operational differences between the two regions.

Costs and benefits of tightly managed power system frequency:

As part of considering the options, the Panel will consider the costs and benefits of changes to the FOS to specify a tighter frequency distribution during normal operation. This will include consideration of improved system security outcomes and potential cost impacts related to system operation, including regulating FCAS costs.

There are risks and costs associated with the power system operating more often at frequencies at the edges of the NOFB, including:

- increased operating and maintenance costs for generation plant due to excessive movement caused by governor response to frequency deviations
- reduction in system security for contingencies that result in significant changes in transfer across interconnectors
- potential need for additional contingency FCAS to maintain the same level of system security given increased variability of system frequency
- increase in regulating FCAS costs
- possibility of further withdrawal of PFR due to the added burden on existing PFR.

The Panel is also interested in stakeholder views on the matter of introducing the NOPFB as part of the FOS.

QUESTION 1: DEFINING THE REQUIREMENT FOR FREQUENCY PERFORMANCE DURING NORMAL OPERATION

- What considerations should be taken into account when defining the target for frequency performance during normal operation?
- What are stakeholders' views on the potential options for refining the target for frequency performance during normal operation?
- Are there any regionally specific issues that should be taken into consideration when setting requirements in the FOS for normal operation?
- What stakeholders' views on the costs and benefits to generators associated with power system frequency being held more closely to 50 Hz during normal operation?

- What are stakeholders' views on the system wide costs and benefits of specifying that system frequency should be held more closely to 50 Hz, as proposed by AEMO?

4.2.4 The primary frequency control band (PFCB)

As discussed above in section 2.2.1, recent changes to the rules required all scheduled and semi-scheduled generators to provide primary frequency response.

Automatic PFR can be implemented on responsive plant with a deadband which creates a zone of insensitivity to small changes in frequency. AEMO may specify a maximum allowable deadband for affected generators in its Primary Frequency Response Requirements.[41] This deadband must not be narrower than the primary frequency control band (PFCB), which is defined in Chapter 10 of the NER as:

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

The PFRR set out a requirement that scheduled generators and semi-scheduled generators set their generating systems to operate in frequency response mode within one or more performance parameters (which may be specific to different types of plant). These parameters must include maximum allowable deadbands (which must not be narrower than the primary frequency control band — the range of 49.985 Hz to 50.015 Hz or such other range as specified by the Reliability Panel in the FOS) outside of which scheduled generators and semi-scheduled generators must provide primary frequency response.

In its paper on *Enduring PFR arrangements for the NEM*, AEMO noted that the application of "deadbands" in a control system determine the point at which control action begins. The larger the deadband in frequency response controls, the larger the permitted level of uncontrolled frequency variation. In the paper, AEMO compared three potential ranges for generator governor deadbands:[42]

> - Narrow deadband (between 0 and ± 0.015 Hz) provides the most stable control of frequency, and the most robust response to and damping of disturbances. This improves the overall resilience of the power system during major system events and abnormal operating conditions, and enhances the effectiveness of secondary control.
> - Moderate deadband (± 0.15 Hz) by itself provides no control of frequency within the NOFB and is not consistent with best practice internationally. PFR would act only after frequency has significantly departed from 50 Hz, reducing the weight of the system to arrest rate of change of frequency (RoCoF), resulting in a less

41 Clause 4.4.2A(b)(1)(i) of the NER.

42 AEMO, Enduring PFR requirements for the NEM - Technical white paper, August 2021, pp.18-19.

resilient power system following contingency events. Adjusting reserve and secondary control parameters alone would be unable to establish control within the NOFB under normal operating conditions.

- Wide deadband (± 0.5 Hz) by itself would provide no control of frequency over a 1 Hz range. PFR would operate only after a very large deviation of frequency, with a material risk of not arresting high RoCoF events, and a significant reduction in resilience. The Frequency Operating Standard (FOS) would be consistently breached. Such a lack of control is an unacceptable way to operate a national power system.

Panel Commentary

The Panel notes that it remains appropriate to consider the costs and benefits of setting the PFCB at a narrow, moderate or wide range. While noting the views of AEMO set out in the *Enduring PFR arrangements for the NEM - technical white paper*, the Panel provides the following commentary on these potential settings:

- Narrow deadband (between 0 and ± 0.015 Hz) would improve the overall resilience of the power system during major system events and improve performance within the NOFB. All generators, regardless of costs, would be required to provide this response if available.
- Moderate deadband (± 0.15 Hz) by itself provides no control of frequency within the NOFB. Other mechanisms would be required to establish control within the NOFB under normal operating conditions. This setting would provide additional response beyond existing FCAS markets to manage larger deviations but only after the frequency has departed the NOFB.
- Wide deadband (± 0.5 Hz) by itself would operate only after a very large deviation of frequency. This would provide an additional safety net above current mechanisms, but on its own this would likely mean a material risk of not arresting high RoCoF events.

The Panel also recognises the interaction of mandatory PFR with other mechanisms that support control of power system frequency. This includes frequency response delivered by plant enabled to provide a market ancillary service. Furthermore, the Panel notes the potential for the voluntary PFR to be provided by market participants in response to future *Primary frequency response incentive arrangements*, currently under development by the AEMC. These incentive arrangements will not be implemented in time to inform the Panel's determination for this review. However, it may be appropriate to revisit the setting for the PFCB, following a suitable period of operating the system with the incentive arrangements in place.

The current PFCB is specified in the NER at the narrow range of ± 0.015 Hz. The Panel notes that this setting was introduced in the absence of a clearly defined frequency performance standard in the FOS. Therefore, it is now appropriate to actively consider the appropriate setting for the PFCB within the context of other settings in the FOS, including the NOFB and any other specification for frequency performance during normal operation, although updating the PFCB would be a non-trivial change and necessitate a coordinate program for

AEMO to revise the generator deadbands in the PFRR and coordinate the related changes to generator control systems. The Panel will seek advice from AEMO on the frequency control implications related to the PFCB. The Panel is also interested in stakeholder views on the matter.

QUESTION 2: THE PRIMARY FREQUENCY CONTROL BAND

- What considerations should the Panel have in relation to the setting of the PFCB?
- What are stakeholders' views on the setting of the PFCB?
- Are there any regionally specific issues that should be taken into consideration when setting for the PFCB?
- What are stakeholders' views on the potential implementation costs associated with changing the PFCB?
- What are stakeholders' views on the costs and potential savings of the PFCB being set at a narrow, moderate or wide setting, as described above?

5 A SYSTEM STANDARD FOR THE RATE OF CHANGE OF FREQUENCY

As the dominance of synchronous machines in the power system decreases, the level of synchronous inertia in the power system is expected to reduce. 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. Therefore, as system inertia decreases, there is an expectation that the rate of change of frequency (RoCoF) following contingency events will increase.[43]

The potential need for a system RoCoF limit is included in AEMO's Initial roadmap for the *Engineering framework* to address system requirements as levels of synchronous inertia reduce.[44]

The Panel notes that a system standard for RoCoF would help define the requirements for the secure operation of the power system, in the context of declining levels of power system inertia. This section sets out the Panel's consideration of a RoCoF limit, including:

- Section 5.1 — Description and definition of RoCoF
- Section 5.2 — Declining levels of synchronous inertia
- Section 5.3 — Current arrangements for managing RoCoF
- Section 5.4 — A system standard for RoCoF.

5.1 Description and definition of RoCoF

RoCoF defines how quickly power system frequency changes. It is particularly important following contingency events for three reasons:

- It determines the amount of time that is available to arrest the change in frequency before it moves outside of the permitted bands of the frequency operating standard following a generation or load event.
- High RoCoF may compromise the effectiveness of key emergency controls, such as under-frequency load-shedding (UFLS), as there may not be sufficient time to adequately react.
- It also relates to the continuous operation of power system plant, some of which have protection systems that will disconnect the plant from the power system when RoCoF exceeds certain thresholds.[45] The generator performance standards are discussed further in section 5.3.1.

Post-contingency RoCoF is proportional to the change in supply or demand as a result of the contingency event and inversely proportional to the level of system inertia at the time that the contingency occurs. The greater the size of the contingency event, or the lower the

43 This assumes no other changes are made to the operation of the power system such as constraints to minimise the size of the contingency.

44 AEMO, *Engineering framework* - Initial Roadmap, ID012, December 2021, p.28.

45 GE Energy Consulting, *Advisory on Equipment Limits associated with High RoCoF*, April 2017

system inertia, the faster the frequency will change. More inertia in the power system means a slower initial decline of power system frequency.

The relationship described in Box 2, demonstrates the mathematical interaction between RoCoF, contingency size and the level of inertia in the power system. Therefore, for a given system RoCoF limit there is an operational trade-off between contingency size and level of inertia. In theory, a system target for RoCoF could be achieved by limiting the size of a contingency or maintaining an adequate level of inertia in the power system to control post contingent RoCoF. In practice, increasing the level of inertia in the operational timeframe could involve any combination of the following:

- Altering dispatch to increase the provision of inertia from synchronous units or other approved providers.[46]
- Constraining off devices that do not provide inertia, so as to make room for units that do provide inertia.

BOX 2: DETERMINING THE INSTANTANEOUS RATE OF CHANGE OF FREQUENCY

The relationship between the instantaneous rate of change of system frequency, system inertia and the size of the contingency is defined by the following equation.

$$RoCoF = (25 \times \Delta P)/H$$

Where:

- RoCoF = the instantaneous rate of change of frequency (Hz/second)
- ΔP = the size of the contingency (MW)
- H = inertia (MW.seconds)

Higher levels of inertia increase the time available to respond to a major disturbance and arrest system frequency before exceeding the relevant contingency bands in the FOS. Figure 5.1 illustrates how the rate that the frequency changes determines the amount of time available to arrest system frequency following a contingency event. The three lines in the figure show the potential impacts on the level of frequency from different levels of initial RoCoF. The figure assumes that a loss of generation occurs with the system frequency at 50 Hz, that there are no services available to arrest the decline in frequency until six seconds after the contingency event — the time period associated with the current fastest response service — and that all generating units can tolerate the frequency change:[47]

- For the frequency to remain within the current operational frequency tolerance band (above 49 Hz), the initial RoCoF cannot exceed 0.167 Hz/s (blue line).

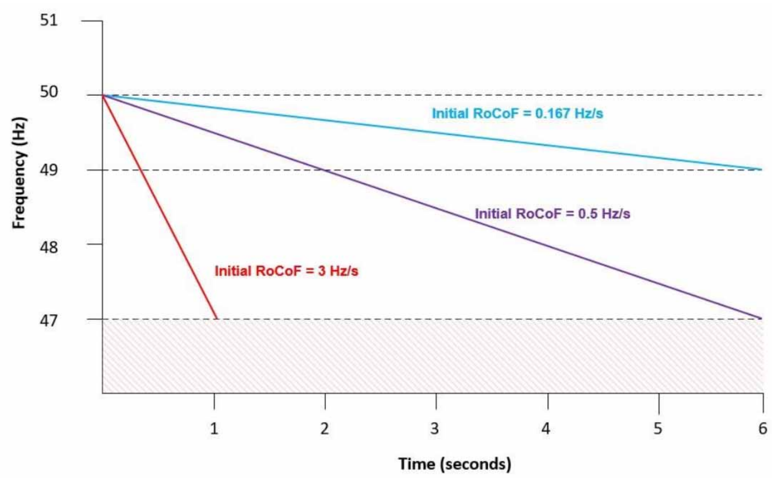
46 Note: virtual synchronous machines are not yet able to provide inertia services in the NEM, although future reforms may change this.

47 Node: in practice the response takes effect over the six-second period rather than precisely at the six-second mark. It should also be noted that the system frequency at the time of the contingency may not be exactly 50 Hz. Under normal operating conditions, the system frequency may be as low as 49.75 Hz.

- For the frequency to remain within the current extreme frequency excursion tolerance limit (above 47 Hz), the initial RoCoF cannot exceed 0.5 Hz/s (purple line).
- An initial RoCoF of 3 Hz/s would lead to the frequency falling below the extreme frequency excursion tolerance limit after one second (red line).

Under the current operational settings under-frequency load shedding commences at 49 Hz and generators are not required to stay connected to the power system for frequencies below 47 Hz. There is a significant risk of a cascading failure resulting in a black system if system frequency exceeds the extreme frequency tolerance limit.

Figure 5.1: Initial RoCoF determines the time available to respond



Source: AEMC, *System Security Market Frameworks Review* - Directions Paper, March 2017.

Therefore, as post-contingent RoCoF levels increase due to declining levels of system inertia, faster acting contingency reserves are required to rebalance the power system and stabilise system frequency following contingency events. The new very-fast contingency (FFR) services scheduled to commence on 9 October 2023 will help address this need.[48]

5.2 Declining levels of synchronous inertia

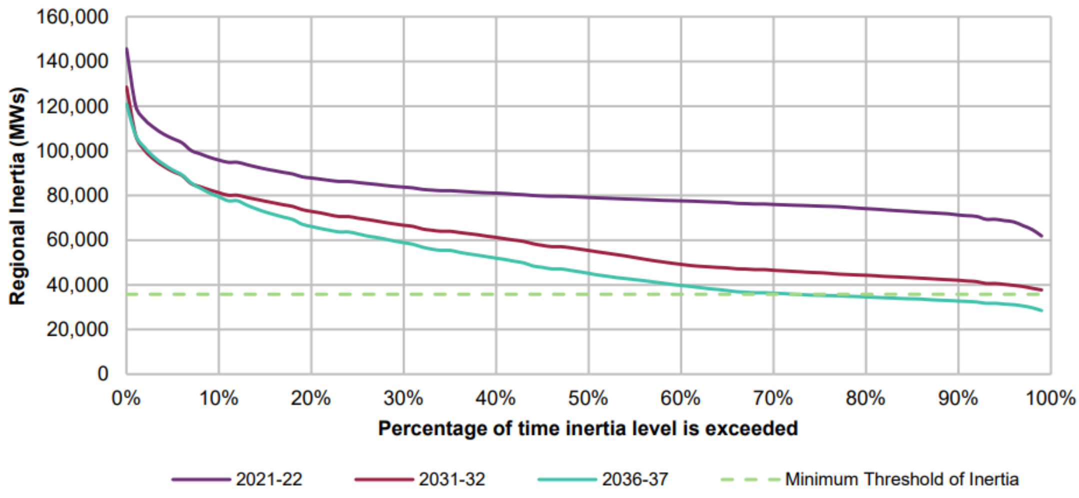
AEMO's draft 2022 Integrated System Plan (ISP) projects declining inertia levels in the national electricity system over the period 2022 through 2037. The projected inertia duration curves under the ISP progressive change scenario for the mainland NEM and Tasmania are shown below. Figure 5.2 shows that by 2036-7 the inertia level available across the NEM mainland for 99% of the time is projected to fall below the minimum threshold of inertia, which is determined by the sum of each region's threshold of inertia (excluding Tasmania). Figure 5.3 shows that the projected level of inertia available in Tasmania for 99% of the time will be significantly lower than the secure level of inertia by 2031-32.

48 AEMC, *Fast frequency response market ancillary service rule 2021*, 15 July 2021.

AEMO's draft 2022 ISP noted that the step change scenario is considered to be the most likely, ahead of the progressive change scenario.[49] The Panel notes that the step changes scenario predicts a more rapid reduction in system inertia levels than shown here.

Figure 5.2: Inertia outlook — Mainland NEM

Inertia projections (*Progressive Change* scenario)			
	2031-32	**2036-37**	**Comments**
Available inertia 99% of the time (MWs)	37,800	28,450	The projections show that the NEM mainland inertia is projected to decline significantly in 2031-32 when compared to 2021-22. By 2036-37 the inertia on the NEM mainland is forecast to decrease below the minimum threshold of inertia.

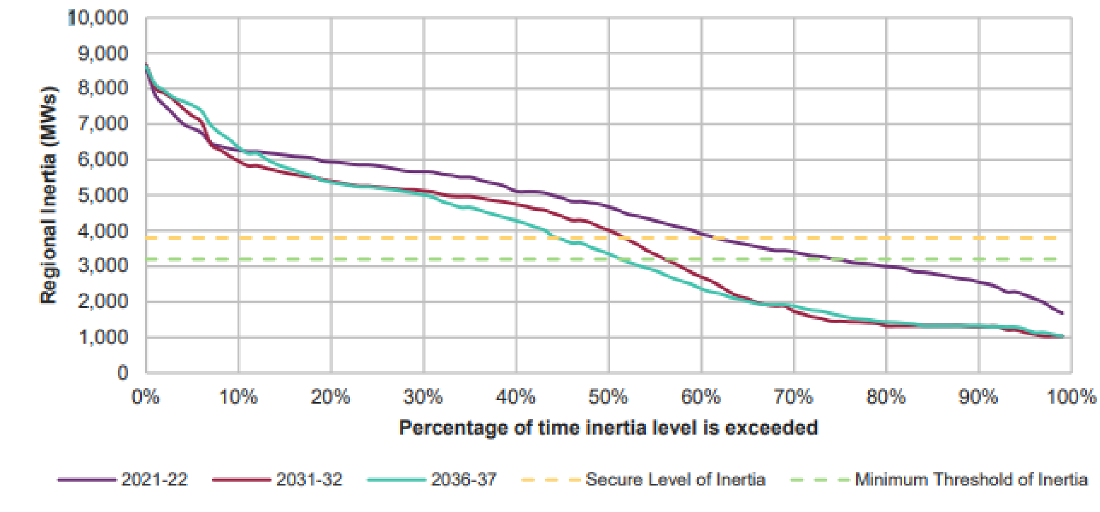


Source: AEMO, *Integrated System Plan 2022* - Draft - Appendix 7. Power system security, December 2021, p.31.

49 AEMO, *Integrated System Plan 2022 - Draft*, December 2021, p.29.

Figure 5.3: Inertia outlook — Tasmania

Inertia projections (*Progressive Change* scenario)			
	2031-32	**2036-37**	**Comments**
Available inertia 99% of the time (MWs)	1,100	1,100	These results are consistent with the inertia projections for Tasmania, to be released in the 2021 System Security Reports‡.
Projected decline below SOLI (MWs)	2,700†	2,700†	
† Although AEMO projects that a shortfall may arise, an inertia shortfall is not formally declared.			



Source: Ibid., p36.

AEMO's integrated system plan projects that the levels of large scale coal- and gas-fired thermal generation will gradually reduce over the coming years, throughout the NEM, and be replaced by inverter connected generation including large scale solar PV, wind power, batteries and behind-the-meter distributed resources like rooftop solar.[50]

It is expected that reducing levels of inertia and the proportional increases in RoCoF will become more widespread. Therefore, the Panel recognises that this may be a good time to introduce a standard, to guide the procurement of services and clarify the responsibilities of AEMO, transmission network service providers (TNSPs) and market participants.

5.3 Current arrangements for managing RoCoF

While the existing FOS does not include a system standard for RoCoF, there are regulatory and operational arrangements for managing RoCoF in the NEM. This section covers:

- Section 5.3.1 — Current arrangements under the NER
- Section 5.3.2 — AEMO operational measures with respect to South Australia and Tasmania.

50 AEMO, *Integrated System Plan 2022* - Draft, December 2021.

5.3.1 Arrangements under the NER

The NER includes provisions that relate to the management of RoCoF in the NEM. These are:

- Generator performance standards for RoCoF — these define the RoCoF withstand capability for connecting generators in the NEM.
- Minimum inertia requirements — these arrangements provide for a minimum level of synchronous inertia on a regional basis in the NEM.
- FFR market ancillary services — these new market ancillary services, which are scheduled to commence on 9 October 2023, will help AEMO to meet the FOS during low inertia operating conditions.

Each of these arrangements is described in further detail below.

Generator performance standards

Clause S5.2.5.3 of the NER sets out the requirements for connecting generators with respect to the response to frequency disturbances, including the technical performance standards for RoCoF withstand capability. The requirements include an automatic and a minimum access standard that inform the negotiation of a connection agreement under clause 5.3.4A. The connecting generator must demonstrate the capability to maintain continuous uninterrupted operation for frequencies within the specified ranges.[51]

The **automatic access standard** requires that a generator must be capable of maintaining continuous uninterrupted operation:[52]

> unless the rate of change of frequency is outside the range of –4 Hz to 4 Hz per second for more than 0.25 seconds, -3 Hz to 3 Hz per second for more than one second, or such other range as determined by the Reliability Panel from time to time.

The **minimum access standard** requires that a generator must be capable of maintaining continuous uninterrupted operation:[53]

> unless the rate of change of frequency is outside the range of -2 Hz to 2 Hz per second for more than 0.25 seconds, -1 Hz to 1 Hz per second for more than one second or such other range as determined by the Reliability Panel from time to time.

The Panel notes that Generators that connected prior to the inclusion of these requirements may have connection agreements that do not meet the existing technical performance standards. The RoCoF withstand capability of generators that connected prior to 2007 is largely unknown. While historical incidents can provide some indication of the capability of

51 Clause S5.2.5.3(b) and (c) of the NER.

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

53 Clause S5.2.5.3(c) of the NER.

these generators, the capability of any particular generator to withstand high RoCoF is largely dependent on the operating conditions that were present at the time of the event.[54]

The Panel notes that the technical capability of power system plant is of key importance for the establishment of system limits for RoCoF. One of the main objectives for such a limit would be to clarify the range of system RoCoF that could be expected following contingency events. The standard would be informed by the technical capability of power system plant and may in turn drive the technical performance standards for connecting generators, as envisaged through clauses S5.2.5.3(b) and (c) of the NER. It is expected that overall system RoCoF withstand capability would be determined with reference to the lowest capability of any equipment connected, a RoCoF above that level may lead to a cascading failure of connected equipment, leading to an increased risk of system separation and collapse.

Further information on the generator technical performance standards with respect to system frequency is included in appendix C.

Minimum Inertia Requirements

As described above in section 5.1, the level of inertia in the power system has a direct impact on the system RoCoF experienced following a contingency event. Therefore, provision of inertia is one way to manage system RoCoF and is related to the consideration of a system RoCoF standard.

The NER includes a framework to maintain sufficient levels of synchronous inertia in the power system to maintain system security in the event of islanding of any NEM region. Under the framework, AEMO must determine the inertia requirements for each inertia sub-network in accordance with the inertia requirements methodology.[55]

The inertia requirements include:[56]

- the minimum threshold level of inertia, being the minimum level of inertia required to operate an inertia sub-network in a satisfactory operating state when the network is islanded; and
- the secure operating level of inertia, being the minimum level of inertia required to operate an inertia sub-network in a secure operating state when the inertia sub-network is islanded.

AEMO must establish if any inertia shortfalls exist in each inertia sub-network.[57] If an inertia shortfall has been identified, TNSPs have an obligation to ensure sufficient inertia network services are available to meet the secure operating level of inertia.[58]

FFR market ancillary services

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

54 GE Energy Consulting, *Advisory on Equipment Limits associated with High RoCoF*, April 2017, p.13.
55 Clause 5.20B.2 of the NER.
56 Clause 5.20B.2(b) of the NER
57 Clause 5.20B.3(a) of the NER.
58 Clauses 4.3.4(j) and 5.20B.4(a) of the NER.

frequency within the existing system operating standards. In July 2021, the AEMC made the *Fast frequency response market ancillary service rule 2021* to introduce two new FCAS products into the NEM to provide Fast frequency response (FFR). 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.[59]

Whilst faster-acting contingency services are able to compensate for lower operating levels of inertia, they do not have an impact on the immediate post-contingent RoCoF. As described in section 5.1, the post contingent RoCoF is a function of the size of the contingency events and the level of inertia in the power system.

It may be appropriate to establish a system limit for RoCoF to assist in the specification and dispatch of FFR services. Along with the specification of the expected size of the largest credible risk, such a limit will support the power system studies to determine the required speed of response for the new FFR services along with the required quantity of service, based on the given power system conditions.

The Reliability Panel will seek further technical advice from AEMO to elaborate on the interaction between the specification and dispatch of FFR services and the potential for a system limit for RoCoF.

5.3.2 AEMO operational measures with respect to South Australia and Tasmania

AEMO currently implements operational mechanisms in parts of the power system to limit post contingent RoCoF to acceptable levels and support power system resilience and security. This section describes the operational measures currently in place to manage specific conditions and risks in the NEM regions of Tasmania and South Australia.

RoCoF management in South Australia

The shift to newer inverter-based resources (IBR) has been more pronounced in some regions of the NEM than others. South Australia, in particular, has experienced a significantly faster transformation as larger proportions of IBR have been integrated into the grid. Interconnection with Victoria and the recent commissioning of four synchronous condensers, specifically designed with flywheels to provide additional inertia, allows for power system security to be maintained in normal circumstances despite the significant reduction in local inertia. However, loss of interconnection with Victoria increases the risks to system security in South Australia as it must rely on inertia provided by synchronous machines within the region.

Increases in IBR have impacted the effectiveness of emergency frequency control services (EFCS) in South Australia. UFLS is designed as a final defence to manage large contingency events through a controlled disconnection of load (for further detail see appendix C). The growth of distributed PV has made South Australia's UFLS much less likely to stop an

59 AEMC, *Fast frequency response market ancillary service rule 2021*, 15 July 2021.

uncontrolled frequency decline, as the distributed PV reduces the active load on the network thereby reducing the effective load shedding when UFLS is triggered.[60]

In response to the specific risks to power system security in South Australia, the South Australian government requires AEMO to apply constraints to limit Heywood flows to keep the RoCoF in South Australia below 3 Hz/s for the non-credible trip of both circuits on the Heywood inter-connector. However, the increased likelihood of cascading failure due to ineffective UFLS operation means the current formulation may no longer meet ElectraNet's limits advice under the regulation in all periods, because RoCoF will exceed 3 Hz/s once cascading failure starts to occur.[61]

RoCoF management in Tasmania

The majority of generating units in Tasmania are hydroelectric combined with an increasing proportion of wind generation. Tasmania is also connected to the mainland by the Basslink HVDC interconnector which provides an asynchronous connection. As a consequence, Tasmania is required to rely entirely on regionally produced inertia to maintain security and arrest any potential RoCoF. Additionally, during a fault, wind farms in Tasmania may temporarily reduce their generation as they switch into low voltage ride through mode in response to the voltage dip from the fault. This secondary reduction in generation can add to the primary contingency event and increase the severity of the associated power system disturbance.[62]

TasNetworks first advised AEMO of network operating limits related to RoCoF in early 2013. Since that time AEMO has implemented dispatch constraints to manage RoCoF limits in Tasmania. These constraints are designed to maintain RoCoF in Tasmania below around 1.1 Hz/sec, which is required to ensure the effective operation of Tasmanian UFLS.

5.4 A system standard for RoCoF

The Panel considers that there could be costs and benefits to including a system standard for RoCoF as part of the FOS, including its potential interaction with other regulatory changes. This section covers:

- Section 5.4.1 — Previous consideration of a system RoCoF standard
- Section 5.4.2 — Interaction of the proposed RoCoF standard with other regulatory reforms
- Section 5.4.3 — Considerations when setting a system standard for RoCoF.

5.4.1 Previous consideration of a system RoCoF standard

The potential inclusion of a system standard for RoCoF has been raised in previous consultation by the AEMC and the Reliability Panel. Most notably, the issue was raised during the AEMC's 2017 consultation on the *Managing the rate of change of power system*

60 AEMO, *Heywood UFLS constraints* - Fact sheet, October 2020, p.1.

61 AEMO, *Heywood UFLS constraints* - Fact sheet, October 2020, p.2.

62 AEMO, *Inertia Requirements Methodology: Inertia Requirements & Shortfalls*, July 2018, p.33.

frequency rule change and during the Panel's previous review of the FOS, which concluded in 2019.

More recently, AEMO has identified the potential need to specify system RoCoF limits to formalise the operational requirements to maintain system security as levels of synchronous inertia decrease. Further detail on the *Engineering framework* is included in section 2.3.[63]

AEMC consultation on *Managing the rate of change of power system frequency*

On 19 September 2017, the AEMC published its final determination for the *Managing the rate of change of power system frequency* rule change.[64] The rule change request was received from the South Australian Minister for Mineral Resources and Energy with the addition of a RoCoF limit also raised by the *Frequency control frameworks review* and the *Fast frequency response market ancillary service* rule change.[65] [66]

The rule change request considered the effect of reductions in synchronous generation in South Australia resulting in a proportional decrease in system inertia. The rule change request recommended the addition of a RoCoF standard as part of the FOS to help guide the level of required inertia or FCAS services.

The final rule introduced an obligation on AEMO to determine sub-networks in the NEM that are required to be able to operate independently as an island and, for each sub-network to determine the minimum required level of inertia and to assess if a shortfall exists or is likely to in the future.[67] Where such a shortfall exists, an obligation was placed on the relevant TNSP to make continuously available the minimum required levels of inertia.

The Panel's 2019 Review of the FOS

The issue of the inclusion of a system standard for RoCoF was raised during the 2019 review, including in submissions by ENA, Engie and TasNetworks.[68] However, the Panel determined that the inclusion of a system standard for RoCoF was not warranted at that time. The Panel was of the view that:

- AEMO's system security responsibility for returning the power system to a satisfactory operating state following a protected event is clearly set out in the NER[69]; and
- AEMO is required to operate the power system within the limits of the technical envelope.[70] This includes consideration of the capability of operating generation plant, network elements and EFCS, including how plants would likely perform under potential RoCoF scenarios that may occur following a contingency.

63 AEMO, *Engineering Framework* - Initial Roadmap, ID012, December 2021, p.28.

64 See: https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque

65 *See: https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review*

66 See: https://www.aemc.gov.au/rule-changes/fast-frequency-response-market-ancillary-service

67 AEMC, *Managing the rate of change of power system frequency - Final determination*, September 2017.

68 Submissions to the 2019 Frequency Operating Standard review Issues Paper: ENA, p.5; Engie, p.5; TasNetworks, pp.8-9.

69 Clause 4.2.4 of the NER.

70 Clause 4.3.1(f) of the NER.

AEMO's *Engineering framework*

In its Initial roadmap for the *Engineering framework*, AEMO identified a number of potential gaps that relate to potential specification of a system limit for RoCoF. These are included in Table 6.1 below.[71]

Table 5.1: Potential gaps related to the management of non-credible contingencies in AEMO's *Engineering framework*

IDENTIFIED GAP	RELEVANCE TO A SYSTEM ROCOF LIMITS
ID007 — Potential need for NEM mainland inertia floor under system intact conditions	A RoCoF limit could inform the required NEM inertia floor required under intact conditions
ID009 — Potential need for inertia dependent contingency FCAS under system intact conditions as inertia reduces	A RoCoF limit could guide AEMO on the procurement of contingency FCAS in a reducing inertia environment
ID012 — Potential need for system RoCoF limits and other operational requirements as inertia reduces	This gap identifies the potential need for a general system RoCoF limit

Source: AEMO, *Engineering framework - Initial roadmap*, December 2021, p.30.

5.4.2 Interactions with other regulatory reforms

Implementing a RoCoF standard as part of the FOS would also inform the operation of the following finalised, open and pending rule change requests. System standards for RoCoF would:

- Inform the specification of the FFR service by AEMO - a RoCoF limit could inform AEMO on the implementation of operation arrangements for FFR. In particular, a RoCoF limit would provide a base value against which FFR specification and requirements can be determined.
- Inform the procurement and scheduling of secure configurations through the mechanism being developed to price, procure and schedule resources through the *operational security mechanism*. The proposed RoCoF standard could inform AEMO on the particular parameters required for each system configuration, including the secure level of system inertia. The Panel and AEMC will consider such implications.
- Inform the procurement and scheduling of inertia through the proposed inertia market ancillary service - maintenance of a satisfactory level of inertia is a crucial component in resisting an increase in RoCoF. Including a standard for RoCoF as part of the FOS could provide guidance on the level of inertia AEMO should procure to maintain system security

71 AEMO, *Engineering framework - Initial roadmap*, December 2021, p.30.

if an inertia MAS were implemented in the future. Generators or units contracted to supply inertia through a potential inertia MAS would also need to be able to withstand a RoCoF at least to the targeted RoCoF limit, otherwise, they would not be able to guarantee the provision of scheduled inertia during times of high RoCoF.

5.4.3 Considerations when setting a system standard for RoCoF

The Panel recognises the complexities involved in setting a RoCoF standard, including:

- the operational conditions that would apply to a RoCoF standard
- the form of a RoCoF standard, including the time period over which RoCoF is measured
- the costs and benefits of implementing a RoCoF standard.

Under what operational conditions would a RoCoF standard be set

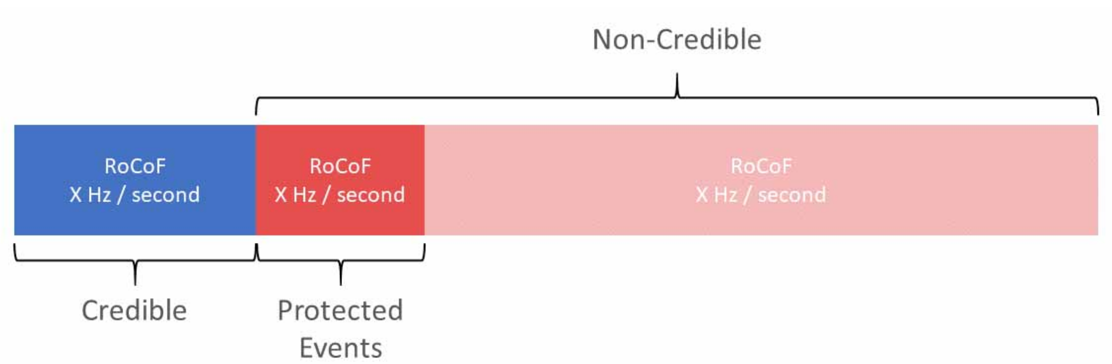
Implementing a RoCoF standard needs to take into consideration relevant operational conditions and could consist of:

- a standard to apply following credible contingency events
- a standard to apply following protected events
- a standard to apply following non-credible contingency events that are not-protected events.

The standard for non-credible contingency events would be set to a higher RoCoF to avoid AEMO consistently procuring system security services to maintain system frequency due to events with a very low probability of occurrence. Put another way, the setting of the standard would recognise both the low probability of a non-credible separation and the high consequences of such an event, that is a greater loss of load or generation.

Figure 5.4 shows how these RoCoF system standards might be set.

Figure 5.4: **Possible RoCoF system standards**



Source: AEMC

What form would a RoCoF standard take?

A RoCoF standard would consist of a maximum change in frequency over a specified time period, ie x Hz/s measured over a period of y seconds. The Panel's determination of a RoCoF standard would also need to consider the operational needs of the electricity network and the capabilities of existing and future generating units. For example, a limit of 2 Hz/s would not be effective if the maximum RoCoF that could be tolerated by individual generators and load was 1 Hz/s. A standard that does not consider the technical capabilities of generating systems and network elements may result in equipment being inadvertently disconnected from the electricity system.

Costs and benefits of setting a RoCoF limit

An increase in RoCoF would intensify the difficulty of maintaining the frequency within the bounds defined by the FOS. Setting a RoCoF limit would provide:

- a higher probability of generators remaining online following the occurrence of a contingency event
- time for emergency frequency control schemes to operate effectively
- time for frequency control ancillary services in the islanded sub-network to respond and recover the frequency to normal operating levels.

The costs of implementing a RoCoF limit are being considered by the Panel as part of this review of the FOS. Setting a RoCoF limit could result in costs related to:

- the procurement of additional system security services to meet the standard
- the setting of additional constraints on dispatch to meet the standard
- delivering the required level of technical capability for new plant connecting to the network.

The Panel is interested in stakeholder views on the inclusion and definition of a RoCoF standard as part of the FOS.

QUESTION 3: DEFINING A SYSTEM STANDARD FOR ROCOF

- What should be taken into account in setting system limits for RoCoF?
- If the Panel chose to set a RoCoF standard, what format should it take?
- If the Panel chose to set a RoCoF standard, what factors should be taken into consideration?
- Would the establishment of the RoCoF standard burden stakeholders with significant adherence costs?

6 SETTINGS IN THE FOS FOR CONTINGENCY EVENTS

An important consideration as the power system transforms is the changing nature of operational risks that must be managed to maintain the system in a secure operating state. This is reflected in a number of gaps identified by AEMO's *Engineering framework* for potential actions to meet the needs of the power system over the next ten years.[72]

The Panel recognises the need to review the settings in the FOS for contingency events to provide a clear foundation for the operational performance requirements and limits in the power system. In particular, the Panel will investigate opportunities to update the FOS to help manage the increasing risks to power system security identified by AEMO through the *Engineering framework* and related studies.

This chapter describes and discusses the settings in the FOS that relate to contingency events Each section sets out the Panel's initial considerations of related issues and requests stakeholder input to inform the Panel's considerations.

- Section 6.1 — The frequency bands for credible contingency events
- Section 6.2 — The frequency bands for non-credible contingency events
- Section 6.3 — Limits on the maximum allowable credible contingency event.

6.1 The requirements for system recovery following credible contingency events

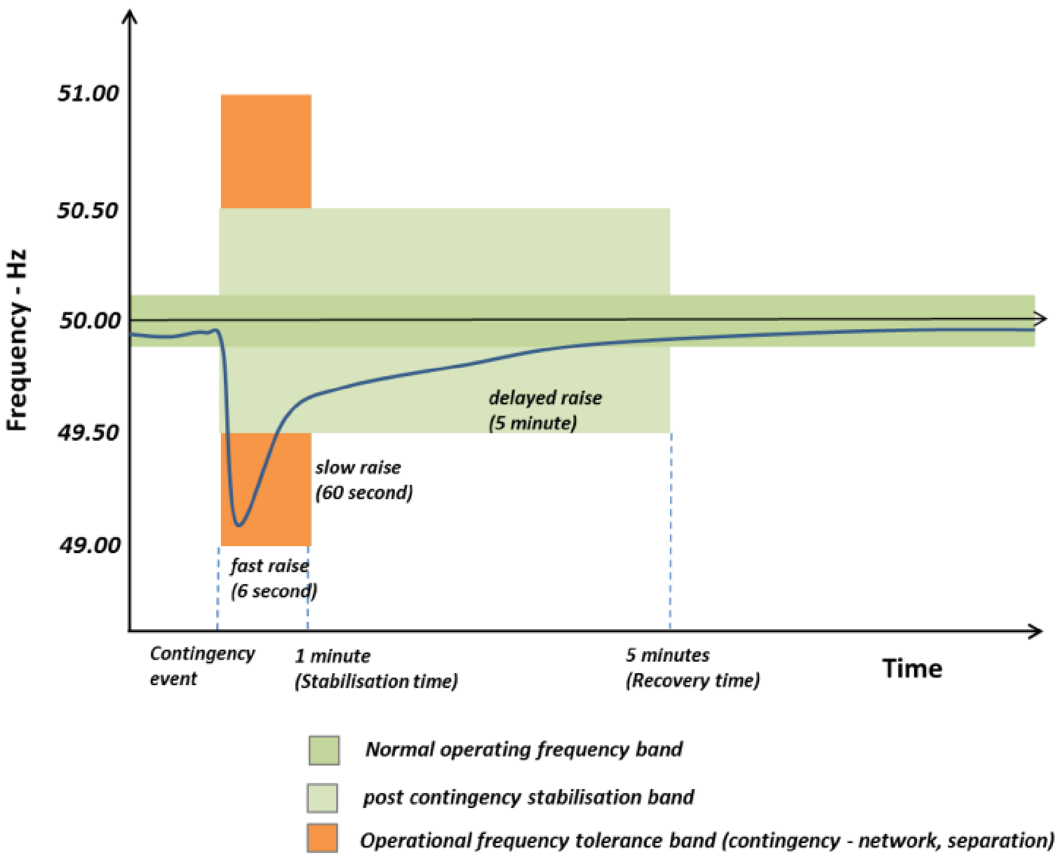
The requirements in the FOS following credible contingency events include the allowable frequency containment bands within which the frequency must be maintained and the times within which AEMO must return the power system frequency to the applicable stabilisation and recovery bands. These settings guide AEMO's activities to maintain the power system in a secure operating state, including the specification and procurement of frequency control ancillary services, which respond to frequency disturbances to rebalance supply and demand and restore the power system frequency to the normal operating frequency band.

6.1.1 What are the existing arrangements in the FOS for the containment and recovery of system frequency following credible contingency events

Under the existing FOS, following a credible contingency event, AEMO is required to maintain the frequency within the applicable containment band, then return the frequency to within the stabilisation band within the applicable stabilisation time and the recovery band within the applicable recovery time. The FOS specifies different settings for Tasmania and the mainland including the relevant bands and recovery times based on the type of event that occurs and the operational situation. Figure 6.1 shows the response following a network event.

72 An overview of AEMO's *Engineering framework* is included in section 2.3.

Figure 6.1: **Frequency deviation and FCAS response**



Source: AEMC, *Frequency Control Frameworks Review - Issues Paper*, p.19.

- System frequency on the mainland shall be contained within the *operational frequency tolerance band* (49.0 – 51.0 Hz) and recovered to within the 49.5 – 50.5 Hz within 1 minute, and to within the NOFB (49.85 – 50.15 Hz) within 5 minutes.
- System frequency in Tasmania shall be contained within the *operational frequency tolerance band* (48.0 – 52.0 Hz) and recovered to within the NOFB (49.85 – 50.15 Hz) within 10 minutes.

The full set of requirements for containment and recovery of the power system following credible contingency events are set out in the FOS.[73] This includes separate tables with respect to the operation of the mainland and Tasmania during interconnected operation and

73 See: https://www.aemc.gov.au/australias-energy-market/market-legislation/electricity-guidelines-and-standards/frequency-0.

for an island that forms within the larger system. There is also a separate operating condition for the operation of the mainland during a state of supply scarcity, which applies when AEMO is reconnecting load following a contingency event that has resulted in load shedding.[74]

In addition to different modes of operation, the FOS also includes different containment, stabilisation and recovery requirements with respect to the following types of credible contingency events:[75]

- generation event
- load event
- network event
- separation event.

The settings in the FOS for contingency events are linked to the technical performance standards for connecting generators under the NER. In particular, the technical standards set out in clause S5.2.5.3 of the NER for response to frequency disturbances include automatic and minimum access standards that refer to the extreme frequency excursion tolerance limits and operational frequency tolerance band specified in the FOS along with the applicable stabilisation time and recovery times.[76]

6.1.2 What are the recent changes to the definition of a contingency event

In March 2022, the AEMC made the *Enhancing operational resilience in relation to indistinct events* rule.[77] This rule expands the contingency event framework to allow AEMO to manage the risk of 'indistinct events', which are threats to power system security that are unpredictable and uncertain and can impact multiple power system elements. It provides AEMO with the increased flexibility to manage these indistinct events while minimising costs to consumers.

Under the final rule, the definition of a 'contingency event' in the NER will be amended from 9 March 2023. The new definition of a contingency event will be:[78]

> A **contingency event** means an event on the power system which AEMO expects would be likely to involve:
>
> (1) the failure or removal from operational service of plant; and/or
>
> (2) a sudden and unplanned change to the loading level of plant.

The new definition covers all equipment involved in the generation, transmission or distribution of electrical energy, as well as sudden and unexpected changes to the level of

74 'Supply scarcity' refers to a mode of operation where, following a contingency event, the frequency has reached the applicable Recovery Band and AEMO considers the power system is sufficiently secure to begin reconnection of load. Under this mode of operation, the frequency performance requirements are relaxed somewhat to allow for the prioritisation of reconnection of load.

75 A discussion of the elements of the FOS is included in appendix A.

76 Further detail on the Technical performance standards under the NER is included in appendix C.

77 National Electricity Amendment (Enhancing operational resilience in relation to indistinct events) Rule No. 1.

78 National Electricity Amendment (Enhancing operational resilience in relation to indistinct events) Rule 2022 No. 1.

output, consumption or power flow of this equipment, which may not involve complete failure and removal from service.[79]

AEMO is required to update its reclassification criteria to ensure it outlines when reclassification of non-credible contingencies is more likely given abnormal conditions and the actions AEMO is likely to take to manage these credible risks. Under the final rule, the update must occur through consultation with relevant stakeholders by 9 March 2023.

6.1.3 Panel commentary

The Panel recognises the need to review the settings in the FOS for contingency events to provide a clear foundation for the operational performance requirements and limits in the power system. In particular, the Panel will investigate opportunities to update the FOS to help manage the increasing risks to power system security identified by AEMO through the *Engineering framework* and related studies.

Previous review of the frequency bands for credible contingency events

During the previous FOS review in 2019, the Panel considered the following specific issues related to the settings in the FOS for credible contingency events:

- Based on the technical capability of the existing generation fleet, whether the generation and load change band, 49.5 – 50.5 Hz that applies in the mainland NEM should be widened to be equal to the network event band and the operational frequency tolerance band, 49.0 – 51.0 Hz.
- Whether it is appropriate for the settings in the FOS that relate to the minimum thresholds for generation and load events to be refined to better match the regional characteristics of the power system.

At the time, the Panel:

- determined to maintain the existing settings in relation to the management of credible contingencies in the NEM, supported by AEMO advice that, in the context of the ongoing frequency control work program, the settings in the FOS that apply to the management of contingency events should be maintained.[80]
- noted that these issues may warrant further consideration in a future review of the FOS, when the priority issues identified through the AEMC-AEMO frequency control work plan were resolved - including the reinstatement of effective frequency control during normal operation.

The potential alignment of the generation and load change band for the mainland with the operational frequency tolerance band

In the 2019 review, the Panel noted AEMO's advice that widening the generation and load change band would reduce the operating safety margin that currently exists in the FOS for

79 AEMC, *Enhancing operational resilience in relation to indistinct events - Final determination*, 3 March 2022, pp.ii-iii.

80 AEMC Reliability Panel, *Review of the Frequency operating standard* - final determination stage 2, April 2019, p.28.

the NEM to allow for stabilisation and recovery of the power system following contingency events.[81] The operating safety margin in the existing FOS is a result of the frequency gap between the lower limit of the generation and load change band (49.5 Hz) and the frequency at which automatic under-frequency load shedding commences (49.0 Hz). This buffer reduces the likelihood of load shedding for credible contingency events, to account for operational uncertainties and may help to reduce the quantity of load that is shed following a non-credible contingency.

The Panel acknowledges the importance of operational buffers in relation to the management of contingency risks and the maintenance of the power system in a secure operating state. At the same time, the Panel notes that the settings in the FOS should accurately and consistently reflect the target for system frequency performance while recognising the costs and benefits of that target. As such the Panel is interested in stakeholder views and technical advice from AEMO in relation to the setting of the following elements of the FOS that apply in the mainland during interconnected operation:

- the generation and load change band: 49.5 – 50.5 Hz
- the network event band: 49.0 – 51.0 Hz
- the operational frequency tolerance band: 49.0 – 51.0 Hz.

The minimum thresholds for generation and load events

In the 2019 review, the Panel noted that variation of the thresholds in the FOS for generation and load events were not likely to deliver material benefits at that time. This is because these thresholds do not result in any costs being incurred as the settings do not drive the procurement of any market ancillary services by AEMO.

The Panel is interested in stakeholders' views as to whether there is any relevant new information or whether the existing minimum thresholds for generation and load events should be maintained.

The operational frequency tolerance band and requirements for connecting generators under the NER

The Panel is aware of an issue arising from the interaction between the FOS and the requirements in the NER for Generating system response to frequency disturbances under clause S5.2.5.3 of the NER.

As a result of formatting changes made to the FOS through the 2019 review, a connecting generator must demonstrate a capability for continuous uninterrupted operation within the range 48 Hz and 52 Hz for 10 minutes to achieve the automatic access standard for Generating system response to frequency disturbances.[82]

- 48 – 52 Hz is the widest setting in the FOS for the operational frequency tolerance band. This range applies during supply scarcity in the mainland NEM.

81 Reliability Panel, *Review of the Frequency operating standard* - Final determination stage 2, April 2019, p.31.

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

- 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, a range of 49 – 51 Hz was applied under clause S5.2.5.3 for the Operational frequency tolerance band in the mainland NEM. The Panel notes that the operational frequency tolerance band that applies during supply scarcity was originally set by the Reliability Panel in 2009 as 48.0 – 52.0 Hz. However, the 2009 FOS did not explicitly link the containment band that applied during supply scarcity in the mainland to the setting for the Operational frequency tolerance band in the NER.[83]This supported the interpretation of the Operational frequency tolerance band as 49 – 51 Hz for the mainland NEM.

The Panel acknowledges that the application of the Operational frequency tolerance band for supply scarcity through clause S5.2.5.3 may have a material impact on costs for connecting generators. Therefore, the Panel is interested in stakeholders' views on any cost impacts that may be incurred as a result of this setting. The Panel will also seek advice from AEMO on the operational requirements with respect to the operational frequency tolerance band given the interaction with the technical standards for connecting generators.

QUESTION 4: THE FREQUENCY BANDS FOR CREDIBLE CONTINGENCY EVENTS

- What are stakeholders' views on the appropriateness of the existing settings in the FOS for the recovery of the power system following credible contingency events?
- What are the implications for the FOS as a consequence of the revised contingency framework established under the *Enhancing operational resilience in relation to indistinct events* rule?
- What opportunities exist to amend the FOS to help address the increasing operational risks identified by AEMO through the *Engineering framework*?
- Are there any regionally specific issues that should be taken into account when considering the requirements in the FOS that relate to credible contingency events?
- What are stakeholders' views on the appropriateness of the operational frequency tolerance band for supply scarcity (48.0 – 52.0 Hz) and any cost impacts for the connection of new generators?

6.2 The requirements for system recovery following non-credible contingency events

The requirements in the FOS that apply following non-credible contingency events include:

- the management of non-credible events that are designated as protected events by the Reliability Panel under clause 8.8.4 of the NER; and

83 AEMC Reliability Panel, Application of Frequency Operating Standards During Periods of Supply Scarcity, Final determination,15 April 2009

- the management of other non-credible events, including multiple contingency events.

6.2.1 What are the existing arrangements in the FOS for the management of non-credible contingency events

In relation to the management of non-credible contingency events, the FOS includes two separate criteria that relate to non-credible events that are declared as protected events and other non-credible events.

Protected events

A protected event is a non-credible contingency that is defined by AEMO and declared by the Panel.[84] It may include any non-credible contingency or multiple contingency events and aims to limit the impacts of certain high consequence non-credible contingency events, the occurrence of which may otherwise lead to cascading outages that may result in major supply disruptions and potentially a black system condition for all or part of the power system.[85]

Under the existing FOS,[86] following a protected event, AEMO is required to maintain the frequency within the applicable band then return the frequency to the stabilisation band within the applicable stabilisation time. Similar to contingency events, the FOS specifies different settings for the mainland NEM and Tasmania depending on the operational circumstances surrounding the protected event.

The Panel set out in 2019 that the purpose of a protected event is to prevent the system from collapsing into a black system condition, the Panel considered the extreme frequency excursion tolerance limit to form an appropriate frequency band for a protected event.[87]

Other non-credible events

The FOS requires that AEMO use "reasonable endeavours" to stabilise and restore the power system following non-credible contingency events and multiple contingency events that are not protected events. This requirement recognises that it is not practical nor economic to operate the power system in such a way that it would be expected to maintain satisfactory operation following the occurrence of all possible non-credible or multiple contingency events.

The current FOS states that following a non-credible contingency 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 limits*; and
>
> (b) avoid **system frequency** being outside of the applicable *generation and load*

84 Clause 4.2.3(f) of the NER.

85 AEMC, *Emergency frequency control schemes*, rule determination, March 2017, pp.43-44.

86 These settings were determined by the Panel as part of its previous review of the FOS in 2019.

87 Reliability Panel, *Review of the Frequency operating standard* - Final determination, November 2017, pp.27-28.

> *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*.

The complete definitions of each of these types of events can be found in the FOS, which can be found on the AEMC website.[88]

6.2.2 Panel Commentary

The existing regulatory framework for managing risks associated with non-credible contingency events is largely based on the distinction of whether an event is declared as a protected event or not. For non-credible contingency events that are declared as protected events, AEMO may constrain dispatch and procure necessary system services, including regulation and contingency FCAS to be confident that it can meet the applicable containment and recovery requirements set out in the FOS.

However, the arrangements for the management of non-credible risks that are not declared as protected events do not support constraints being applied to dispatch, nor the provision of system services, other than those required for other reasons, such as the minimum inertia requirements and the minimum system strength requirements. The dominant mechanism for responding to non-credible contingency events, other than protected events, is through the coordinating action of emergency frequency control schemes, including under-frequency load shedding and over-frequency generation shedding schemes.

AEMO reviews the risks associated with non-credible contingency events every two years through the *Power System Frequency Risk Review* (PSFRR). In accordance with clause 5.20A.1 of the NER, AEMO's *Power system frequency risk review* considers:

- Non-credible contingency events which AEMO expects could involve uncontrolled frequency changes leading to cascading outages or major supply disruption.
- Current arrangements for managing such non-credible contingency events, including the performance of existing emergency frequency control schemes (EFCS).
- Options for future management of such events, including whether to submit an application to the Panel for the declaration of a protected event.

The Panel understands that the next (and final) *Power system frequency risk review* will be completed by 31 July 2022. Following that, the *Power system frequency risk review* will be replaced by a G*eneral power system risk review* (GPSRR), with the initial GPSRR to be completed by 31 July 2023.[89]

In its Initial roadmap for the *Engineering framework*, AEMO identified a number of potential gaps that relate to the management of risks associated with non-credible events. These include are included in Table 6.1 below.[90]

---

88 See: https://www.aemc.gov.au/australias-energy-market/market-legislation/electricity-guidelines-and-standards/frequency-0.

89 Clause 11.138.2 of the NER.

90 AEMO, *Engineering framework - Initial roadmap*, December 2021, p.30.

Table 6.1: **Potential gaps related to management of non-credible contingencies in AEMO's *Engineering framework***

IDENTIFIED GAP	RELEVANCE TO NON-CREDIBLE CONTINGENCY EVENTS
ID59 — Need to review alignment of NER framework with regional contingency FCAS requirements for non-credible events	This gap identifies the potential misalignment of NER frameworks with regional FCAS requirements for non-credible contingency events
ID158 — Limited ability to pre-emptively manage non-credible event risk in operational timeframes resulting in increasing reliance on special protection schemes	This gap identifies the potential lack of flexibility for AEMO to proactively manage non-credible event risk

Source: AEMO, *Engineering framework - Initial roadmap*, December 2021, p.26.

The Panel is interested in stakeholder views and AEMO advice in relation to the adequacy of the existing requirements in the FOS for the management of non-credible contingency events.

QUESTION 5: THE FREQUENCY BANDS FOR NON-CREDIBLE CONTINGENCY EVENTS

- What are stakeholders' views on the appropriateness of the existing requirements in the FOS for the management of protected events?
- What are stakeholders' views on the appropriateness of the existing requirements in the FOS for the management of non-credible contingency events, that are not declared as protected events?
- Is there a need for the FOS to further clarify the expectations of the operation of the power system following a non-contingency event?
- Are there any regionally specific issues that should be taken into account when considering the treatment of non-credible contingencies in the FOS?

6.3 Limits on the maximum allowable credible contingency event

The FOS for Tasmania includes a limit on the largest allowable generation event for the Tasmanian power system. This limit clarifies the allowable technical operating envelope for the Tasmanian power system with respect to the credible risks posed by the loss of generation from a single generating system or a single dedicated connection asset providing connection to one or more generating systems.

The Panel reviewed the setting for the Tasmanian generation event limit in 2019, and at the time noted the impact of this limit on the operation of the Musselroe windfarm. The Panel wishes to revisit the current setting of 144 MW to determine whether it continues to remain fit for purpose.

Given the changing nature of risks in the power system, as captured by AEMO's *Engineering framework*, the Panel also intends to consider whether the limit on the largest allowable generation event in Tasmania should be extended to cover other credible contingency events, such as load and network events.

The Panel is also interested in stakeholders' views in relation to the potential inclusion of a limit for the largest allowable credible contingency event for the mainland NEM.

6.3.1 The generation event limit that applies in Tasmania

The FOS includes a limit of 144 MW for the largest allowable generation event in the Tasmanian system. This limit was introduced in 2008 as part of market changes related to the commissioning of the 210 MW Tamar Valley combined cycle gas turbine. The provision of automatic load shedding or other similar arrangements can be arranged to allow for generating systems to be dispatched in excess of 144 MW.

In 2019, the Panel revised the definition of a generation event to include the disconnection of generation as the result of a credible contingency in relation to a dedicated connection asset providing connection of one or more generating systems to the shared transmission network. This revision was proposed by TasNetworks to address a concern that the operational risk landscape in the Tasmanian power system may be degraded by an increasing number of renewable generating systems connecting to the Tasmanian power system via dedicated connection assets.[91] In the absence of changes to the standard, there was the potential for an increase in situations where the combined size of the generating units behind a single transmission element would exceed 144 MW.

As part of the 2019 FOS review, the Panel sought advice from AEMO in relation to the limit on the largest generation event in Tasmania. At that time, AEMO advised that a cautious approach should be taken in relation to any consideration of an increase of the limit from 144 MW, and that such a change should not be undertaken until all affected parties have undertaken adequate consultation. AEMO noted that while the Tasmanian power system currently accommodates contingency events over 144 MW for a small percentage of the time, such a change would make such an operating state normal practice rather than an exception.

As noted in the Panel's 2019 determination, after taking into account the impact of network losses on the dedicated connection asset that connects Musselroe windfarm to the shared network, the revised definition was expected to result in the partial curtailment of the Musselroe wind farm from a maximum dispatchable generation level of 168 MW to a maximum dispatchable level of around 153 MW. This impact could be alleviated through the

91 TasNetworks, Submission to the 2017 Review of the Frequency operating standard - Issues Paper, pp.2-5.

establishment of load shedding, or other similar arrangements, tied to the disconnection of the Musselroe windfarm.[92]

The Panel is interested in whether the existing limit of 144 MW continues to be appropriate for the Tasmanian system. The Panel notes that the commencement of the FFR market in October 2023 may shift the operational conditions in the Tasmanian system, due to the expected availability of more and faster contingency reserve services to help rebalance the power system following contingency events. As such the Panel is interested in receiving updated advice from AEMO on the need for the limit on the size of a generation event in the Tasmanian system and the recommended setting for such a limit. The Panel is also interested in stakeholder views on this matter.

6.3.2 Potential to extend the generation event limit to cover other credible contingency events

The Panel recognises that the nature of power system risks is changing due to the existence of new technologies and patterns of behaviour. This includes new large-scale users of electricity, such as battery energy storage systems and hydrogen production facilities, and the coordinated action of aggregations of smaller distributed energy resources, such as residential batteries, PV and electric vehicle charging.

These changes are referenced in the following potential gaps, identified by AEMO in the Initial roadmap for the *Engineering framework*:

- ID040: Increasing contingency sizes due to DPV disconnection during bulk power system disturbances[93]
- ID155: Risk of large aggregate changes due to the unintended common-mode response of equipment with the same or unknown settings[94]
- ID418: Increased contingency risks associated with loss of flow paths connecting significant REZs to main transmission system[95]
- ID081: Potential risk of increasing contingency sizes associated with unexpected disconnection of new large loads and other local stability and power quality impacts.[96]

Table 6.2: Potential gaps related to maximum allowable credible contingency event limits in AEMO's *Engineering framework*

IDENTIFIED GAP	RELEVANCE TO NON-CREDIBLE CONTINGENCY EVENTS
ID040 — Increasing contingency sizes due to DPV disconnection during bulk power system disturbances	This gap identifies the risk of uncertainty surrounding

92 The Panel understands that a Generator contingency scheme (GCS) connected to the Musselroe windfarm commenced operation in December 2021. This helps to alleviate the constrained operation of Musselroe windfarm due to the application of the 144 MW limit on the largest generation event in Tasmania.

93 AEMO, Engineering framework - Initial roadmap, December 2021, p.26.

94 Ibid.,p.27.

95 Ibid.

96 Ibid.

IDENTIFIED GAP	RELEVANCE TO NON-CREDIBLE CONTINGENCY EVENTS
	network stability following large non-credible contingencies
ID155 — Risk of large aggregate changes due to the unintended common-mode response of equipment with the same or unknown settings	This gap identifies the risk of large non-credible contingencies due to synchronised behaviour of equipment
ID418 — Increased contingency risks associated with loss of flow paths connecting significant REZs to main transmission system	This gap identifies the non-credible contingency risk of damage to network transmission equipment connecting renewable energy zones (REZs)
ID081 — Potential risk of increasing contingency sizes associated with unexpected disconnection of new large loads and other local stability and power quality impacts	This gap identifies the risk to system stability from the unexpected disconnection of new large loads

Source: AEMO, *Engineering framework - Initial roadmap*, December 2021, p.26.

In the context of these projected operational challenges, it may be appropriate to consider the extension of the existing limit on the maximum allowable generation event to cover other credible contingency events, such as load and network events.

QUESTION 6: MAXIMUM CONTINGENCY SIZE IN TASMANIA

- What are stakeholders' views on the appropriateness of the current limit in the FOS for the largest allowable generation event in Tasmania?
- What are stakeholders' views on whether the limit on the maximum allowable generation event should be extended to cover other credible contingency events, including load and network events?

6.3.3 Potential limits for the largest credible event in the mainland NEM

The current FOS does not include a maximum contingency size for the mainland NEM and meeting system requirements throughout the NEM as traditional sources of energy retire and new VRE technologies emerge is a major component of AEMO's Engineering framework and has resulted in potential gaps being identified in relation to managing tail-end risks and building system resilience. Intermittent power sources have characteristics that could increase the volatility of the network and threaten the overall frequency stability.

Implementing a maximum contingency size limit in the mainland NEM may incur costs in relation to the size of new connections to the power system and the potential dispatch outcomes for new and existing plants. In comparison, the current operational impact of the generation limit in Tasmania is relatively limited, resulting in the constrained dispatch of one generating system. The economic benefits of such a limit in the mainland require further exploration given the greater availability of FCAS during interconnected operation of the system.

The costs and benefits of specifying a limit

The specification of a limit in the FOS for the maximum contingency size is likely to have a material impact on investment decisions for new generation plant and potentially on the dispatch outcomes for existing plant. At the same time, the Panel is aware that there may be a need to clearly specify the technical operating limits of the power system to support secure power system operation and provide clarity to potential investors. For example, a limit would provide increased certainty in the connection process as to what size and connection arrangement is permissible.

The Panel considers that a limit on the largest credible contingency could specify the extremity of the allowable operating envelope for the power system. However, the specification of such a limit in the FOS would be relatively static, subject to change through a Review of the FOS by the Panel at a later date. Therefore, such a limit should be set as wide as is practical and is best determined through technical power system advice. The limit specifies a safe operating range, with which economic dispatch can be allowed to operate to determine the most efficient way to meet consumer demand for electricity and provide for contingency services to manage power system security risks. Box 3 explores the dynamic co-optimisation of FCAS and energy dispatch through the NEM dispatch engine (NEMDE) linear optimisation engine.

BOX 3: CONSIDERATION OF DYNAMIC OPTIMISATION OF RISK IN ENERGY DISPATCH

The quantity of FCAS and energy reserves required in the power system is driven by the size of the largest credible risk. However, the dispatch of generation through NEMDE does not take into account the size of the contingency risk associated with dispatch outcomes, nor the economic cost of frequency control ancillary services to manage this risk. This form of dynamic optimisation of energy dispatch and FCAS requirements is neither explicitly required nor proscribed under the NER. However, as noted by the Panel in its 2019 determination for the FOS, such an arrangement would align with the existing NER requirement for AEMO to operate central dispatch to maximise the value of dispatch offers, dispatch bids and market ancillary service offers.

Dynamic optimisation of energy and FCAS in dispatch would involve the application of constraints in NEMDE to weigh up the incremental value of generation from the marginal generating unit, in terms of dispatch targets, against the incremental cost of providing contingency raise services to protect against the disconnection or failure of that generating unit. This form of dynamic optimisation of energy dispatch and FCAS requirement was mentioned by Woolnorth Holdings in its submission to the draft determination for stage two of the 2019 Review of the FOS and considered by the Panel when the limit was introduced in 2008.

Source: For scenarios where the generation at risk exceeds 1.5 times the largest regional generating unit, AEMO reconfigures the FCAS constraints in NEMDE to facilitate the optimisation of the generation at risk and the dispatch of contingency FCAS. AEMO, *Constraint formulation guidelines*, 5 December 2013, p.20.

Source: Woolnorth Wind Farm Holding, *Review of the Frequency Operating Standard* – REL0065 Stage 2 review – Woolnorth Submission, January 2019, pp.8-9.

Operational risks of correlated and responsive demand and supply

A maximum contingency limit may also need to consider the potential impacts of large correlated disruptions in VRE, undesirable control scheme interactions, DER disconnection risks, and correlated demand increases. The AEMO *Engineering framework* considers the operational risks of highly correlated responses to price signals (such as negative wholesale prices) or changing weather conditions (such as cloud cover).[97] Such correlated actions could in effect act as large contingencies and could complicate the operational management of power system risks.

The Panel is interested in whether prescribing a fixed maximum contingency size limit could be appropriate for the mainland NEM. The Panel notes that the commencement of the FFR market in October 2023 may shift the operational conditions in the power system, due to the expected availability of more and faster contingency reserve services to help rebalance the power system following contingency events. As such, the Panel is interested in receiving advice from AEMO on the potential need for a limit on the size of the largest credible contingency for which the mainland power system can reasonably withstand. The Panel is also interested in stakeholder views on this matter.

QUESTION 7: MAXIMUM CONTINGENCY SIZE IN THE MAINLAND NEM

- Do stakeholders consider it beneficial to introduce a fixed generation limit in the mainland NEM? If so, how should the limit be set?
- Would the introduction of a limit incur significant costs on AEMO to maintain system security?
- Would the introduction affect the investment or operational decisions of stakeholders?

97 AEMO, *NEM Engineering Framework – Operational Conditions Summary*, July 2021, pp.17-16

7 ACCUMULATED TIME ERROR

This section sets out the settings that relate to accumulated time error that the Panel is considering as part of the review. Each section sets out the Panel's initial considerations in relation to the settings in Tasmania and the mainland respectively and asks questions to promote stakeholder consultation.

- Section 7.1 — The effect of accumulated time error
- Section 7.2 — Previous reviews of accumulated time error
- Section 7.3 — Costs and benefits of limiting accumulated time error.

7.1 What is accumulated time error?

Time error is a measure of the accumulated time the power system has spent above or below exactly 50 Hz. Operation of the power system to maintain time error within limits helps to align the service of electricity through the power system with the assumptions that underpin the energy market. That is, that energy in Megawatts (MW) is generated and delivered to customers through the electricity system that operates at 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 to have a material financial value.[98]

In order to correct any accumulated time error, AEMO applies a small frequency offset to run the power system marginally above (or below) the nominal frequency of 50 Hz for a period of time. This practice is known as time error correction and is a process that is driven through AEMO's Automatic generation control system (AGC) via control of generation units enabled to provide regulation FCAS.

The existing accumulated time error limits are:

- 15 seconds for the mainland NEM; and
- 15 seconds for Tasmania.

7.2 Previous reviews of the limit on accumulated time error

In 2017, the Reliability Panel increased the limit on accumulated time error in the mainland NEM from 5 seconds to 15 seconds, equal to the limit that applied in Tasmania. In 2019, as part of the Panel's stage two determination for the review of the FOS it noted that:[99]

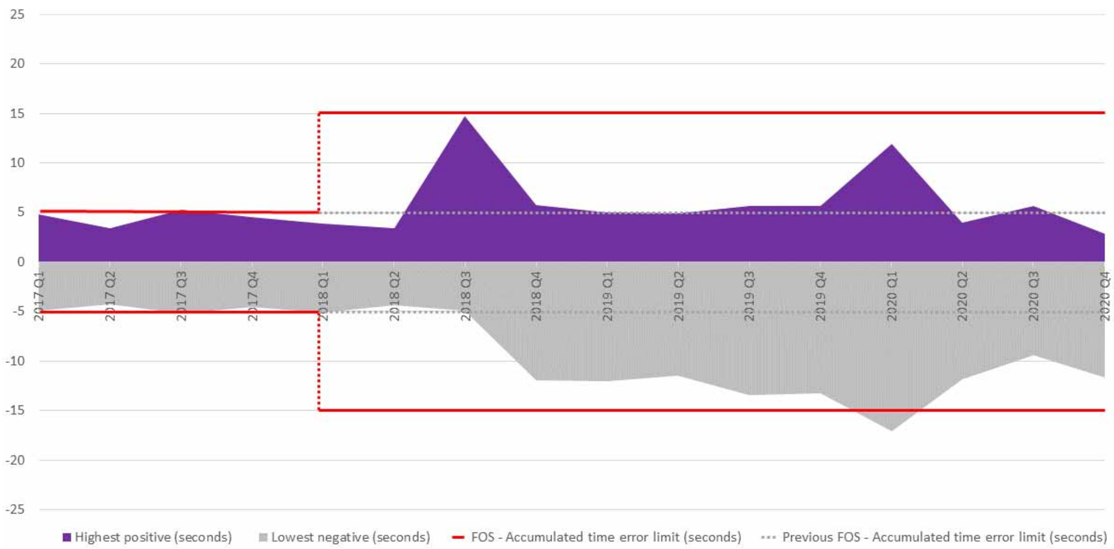
> "Following a suitable period of monitoring it may be appropriate for the Panel to consider further changes to the limit in the FOS in relation to accumulated time error."

98 Between January and March 2018, time error in the European power system accumulated to almost 6 minutes. This level of time error in the European power system was estimated to be equivalent to 113 GWh of "missing energy" relative to the market trading amounts. Reference: ENTSOE, [Press Release] Continuing frequency deviation in the Continental European Power System originating in Serbia/Kosovo: Political solution urgently needed in addition to technical. 6 March 2018.

99 Reliability Panel, Review of the Frequency operating standard - Stage two, 18 April 2019, p.40.

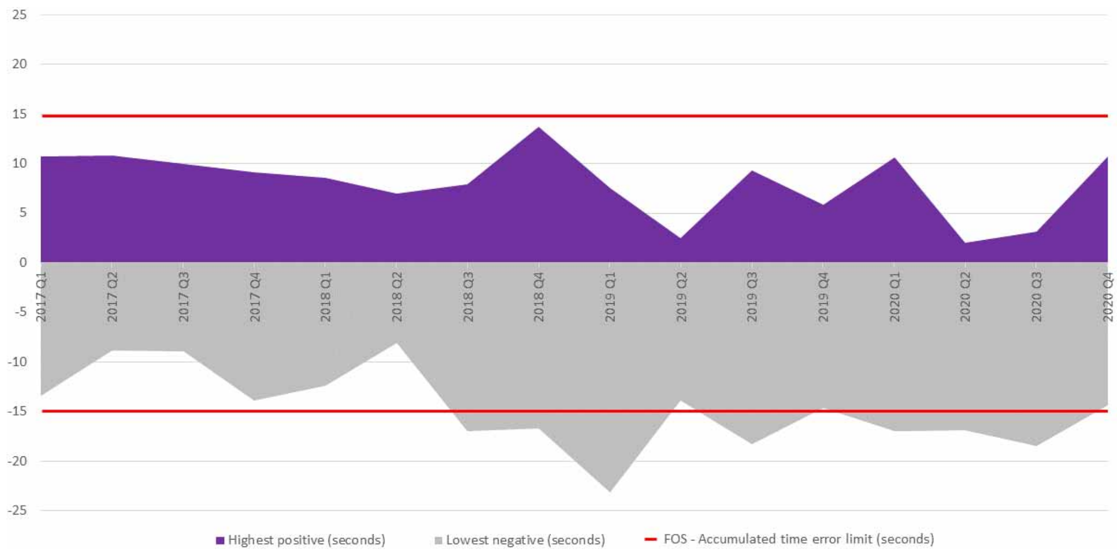
Figure 7.1 and Figure 7.2 show the maximum quarterly accumulated time errors both for the mainland NEM and Tasmania. The loosening of the time error limit as part of the 2019 FOS review led to an increase in the accumulated time error in the mainland as AEMO adjusted to the new FOS requirements, although the average time error in Tasmania remained approximately 24% larger from Q3 2018 until the end of 2020.

Figure 7.1: Maximum accumulated time error in the mainland NEM



Source: AEMO, *Quarterly Frequency and Time Error Monitoring reports Q4 2017* - Q4 2020.

Figure 7.2: Maximum accumulated time error in Tasmania



Source: AEMO, *Quarterly Frequency and Time Error Monitoring report,* Q4 2017 - Q4 2020.

7.3 Potential revision of the standard for accumulated time error

The limits on time error in the FOS and the associated practice of time error correction have been raised in previous FOS reviews. The replacement of synchronous clocks by more modern alternatives has given cause to question the need for AEMO to maintain the same level of synchronicity. AEMO's advice to the 2019 FOS review estimated the costs incurred, over the 18-month period spanning January 2016 to June 2017, to be in the order of $1 million per annum in increased regulation FCAS procurement.[100]

The costs and impact of the accumulated time error may include unforeseen impacts on large and small consumers whose appliances or equipment may still rely on synchronous clocks to tell accurate time.

Significant accumulation of time error also represents a misalignment between energy market dispatch and real power flows. An accumulation of time error due to a sustained reduction in frequency constitutes a lower provision of energy than assumed through the energy market and an overpayment to energy suppliers. Reaching the mainland NEM accumulated time error limit of 15 seconds could represent a real financial loss.

Stakeholders have previously recognised that the accumulated time error serves as a useful metric for the monitoring of delivered frequency performance over time.[101]

100 AEMO, *AEMO response to advice,* Frequency Operating Standard review 2019 (stage 1), p.5.

101 For example, the AEC submission to the stage 2 draft determination of the 2019 review noted that accumulated time error helps identify systemic biases in control systems and periods in the day when the market consistently fails to adequately balance supply and demand requiring an over-reliance on FCAS.

It has been proposed that accumulated time error should be re-expressed such that a rapid change triggers an investigation without requiring AEMO to correct the error. The 2019 FOS review noted that the limit on accumulated time error had value in measuring system frequency performance and maintaining the integrity of the energy market which is based on energy transactions at 50 Hz.

The Panel is interested in stakeholders' views on the appropriateness of the current limit in the FOS for accumulated time error and intends to undertake analysis on the costs and benefits of further revisions to the existing limits, subject to technical advice from AEMO.

QUESTION 8: ACCUMULATED TIME ERROR IN THE NEM AND TASMANIA

- What consequences or costs may arise from the relaxation or removal of the accumulated time error requirement from the FOS for the mainland NEM and for Tasmania?
- What cost do stakeholders incur, if any, of maintaining compliance with the current accumulated time error requirement?
- Are there any other comments or concerns that stakeholders wish to raise with the Panel in relation to accumulated time error?

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
FCAS	Frequency control ancillary service
Hz	Hertz
MASS	Market ancillary service specification
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEM	National electricity market
NEMDE	National electricity market dispatch engine
NEO	National electricity objective
NERL	National Energy Retail Law
NOFB	Normal operating frequency band (49.85 — 50.15 Hz)
NSP	Network service provider
OFGS	Over frequency generation load shedding
PFR	Primary frequency response
TNSP	Transmission network service provider
UFLS	Under frequency load shedding scheme

A THE ELEMENTS OF THE FOS

The FOS incorporates a range of criteria that establish the frequency performance in the NEM for a range of operating conditions. The elements of the FOS include:

- sets of frequency bands that apply to special modes of power system operation, such as an "island system" and "during supply scarcity"
- the range of allowable frequencies in bands corresponding to the operating state of the power system, such as whether a contingency event has occurred
- times for the stabilisation and recovery of the power system frequency following a frequency deviation as a result of a contingency event
- the accumulated time error which is allowed in the NEM, which is related to the historical nature of some clocks that operate based on the frequency of the power system.

Each of these elements of the FOS is described in more detail below in each of the following sections:

- Appendix A.1 — Power system modes of operation
- Appendix A.2 — Frequency bands and recovery time
- Appendix A.3 — Accumulated time error.

A.1 Power system modes of operation

The FOS includes a set of frequency bands that apply for each of the following power system modes:

- Appendix A.1.1 — Interconnected system
- Appendix A.1.2 — Island system
- Appendix A.1.3 — During supply scarcity (NEM Mainland only).

Each of these modes is explored below.

A.1.1 Interconnected system

The FOS for Tasmania and the mainland NEM include a base case for normal operation as an interconnected system. Under this set of conditions, all regions covered by the particular FOS are electrically interconnected and the power system frequency is common throughout that system.[102]

A.1.2 Island system

Separate frequency settings for an island system are included in the FOS for both the mainland and Tasmania. An island system refers to an electrical island that may form as a result of a separation event. The definition of the term "electrical island" in the FOS for the mainland is:

102 The failure of Basslink is not considered a "separation event" for the purpose of the FOS, as the NEM mainland and Tasmania are independent in terms of frequency.

> 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
> 2. contains at least one whole inertia sub-network.

An example of a set of events that may lead to the formation of an electrical island, is the failure of both circuits of the Heywood interconnector between South Australia and Victoria at the same time, resulting in South Australia becoming an electrical island, separate to the rest of the NEM.

For an island system that occurs within the mainland NEM, the normal operating frequency band becomes 49.5 to 50.5 Hz and the operational frequency tolerance band becomes 49.0 to 51.0 Hz. For an island system that occurs within Tasmania, the normal operating band becomes 49.0 to 51.0 Hz and the operational frequency tolerance band becomes 48.0 to 52.0 Hz.

A.1.3 During supply scarcity

In 2008 following significant blackouts that affected Victoria during the 2007 bushfire season, the Panel amended the FOS for the mainland NEM to include separate arrangements for when the power system is in a state of supply scarcity.

A situation of supply scarcity is defined by the FOS as applying when there has been either manual or automatic load disconnection and that load is yet to be reconnected.

The intent of this variation of the FOS for the mainland NEM is to allow for more generation capacity to be targeted towards the restoration of load by reducing the amount of reserve generation required to be set aside for managing contingency events during the restoration process. The result of this approach is that the time to restore the power system can be reduced, while the additional risk associated with the reduction of contingency reserve is considered to be minor.[103]

This applies to the mainland NEM only, not for Tasmania; as the advice provided by NEMMCO at the time did not recommend any change to the Tasmanian FOS on account of supply scarcity.[104] Such an approach in Tasmania was seen as unnecessarily increasing the risk of a further cascading outage.[105]

A.2 Frequency bands and recovery times

The FOS defines the frequency bands and recovery times that apply for NEM operation, during normal operation and in response to contingency events. These frequency bands include the following terms defined in the NER:

---

103 Reliability Panel, April 2008, *Application of Frequency Operating Standards during periods of Supply Scarcity*, pp.13-14.

104 NEMMCO was the market operator prior to the formation of AEMO on 1 July 2009.

105 Ibid., p.2.

- Appendix A.2.1 — Normal operating frequency band and normal operating frequency excursion band
- Appendix A.2.2 — Operational frequency excursion band
- Appendix A.2.4 — Extreme frequency excursion tolerance limit.

The frequency bands that are outside the normal operating band allow for the operation of the power system within a wider range of frequency following contingency events. The stabilisation and recovery times limit the amount of time that AEMO can allow the system to operate in that wider band. Below is a description of each of the frequency bands within the FOS. The existing FOS for the mainland NEM and Tasmania are included available on the AEMC website.[106]

A.2.1 Normal operating frequency band and normal operating frequency excursion band

The normal operating frequency band and normal operating frequency excursion band define the allowable power system frequency under the condition that all major system elements are operating as expected.

The current requirement in the FOS for the mainland NEM and for Tasmanian is that, for 99% of the time, the power system is maintained within the range of 49.85 – 50.15 Hz.[107] During normal operation, in the absence of a contingency or load event, there is an allowance for brief excursions outside this band, but within the normal operating excursion band of 49.75 – 50.25 Hz. Under these conditions, if the power system frequency deviates outside the normal operating frequency band, it must be returned to the normal operating frequency band within 5 minutes.

A.2.2 Operational frequency tolerance band

The operational frequency tolerance band defines the range of allowable power system frequencies in the event of a credible contingency event such as the failure of a single generation or network element. The current FOS for the NEM mainland and Tasmania define different frequency boundaries that apply for different types of contingency events as described in appendix A.2.3.

A.2.3 Generation, network and load contingency bands

In recognition that different types of system events may result in different severity of system disturbance, the FOS differentiates between different types of credible contingency events such as a generation event, a load event or a network event. The definitions provided in the FOS for the mainland, for each of these events are as follows:

- A **generation event** is "a *synchronisation* of a *generating unit* of more than 50 MW or a *credible contingency*, not arising from a *network event*, a *separation event* or a part of a *multiple contingency event*."

106 See: https://www.aemc.gov.au/australias-energy-market/market-legislation/electricity-guidelines-and-standards/frequency-0.

107 Over any 30 day period.

- A **load event** is "an identifiable connection or disconnection of more than 50 MW of customer load (whether at a *connection point* or otherwise), not arising from a *network event*, a *generation event*, a *separation event* or a part of a *multiple contingency event*."
- A **network event** is "a *credible contingency* event other than a *generation event*, a *separation event* or a part of a *multiple contingency event*."
- A protected event is "a *non-credible contingency* event that the Reliability Panel has declared to be a *protected event* under Clause 8.8.4 of the NER. Protected events are a category of non-credible contingency events."
- A **multiple contingency event** "means either a *contingency event* other than a *credible contingency event*, a sequence of *credible contingency events* within a period of 5 minutes, or a further *separation event* in an *island*."

Table A.1 and Table A.2 show the current frequency band settings in the FOS for the NEM mainland and Tasmania (interconnected system).

Table A.1: **Current NEM Mainland frequency operating standards — interconnected system**

CONDITION	CONTAINMENT (HZ)	STABILISATION BAND (HZ)	RECOVERY BAND (HZ)
No *contingency event* or **load event**	49.75 – 50.25 49.85 – 50.15[1]	49.85 – 50.15 within 5 minutes	
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 10 minutes
Separation event	49.0 – 51.0	49.5 – 50.5 within 2 minute	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
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)

Note: 1. 99% of the time.

Table A.2: Current Tasmanian frequency operating standards — interconnected system

<table>
<tr><th>CONDITION</th><th>CONTAINMENT (HZ)</th><th>STABILISATION BAND (HZ)</th><th>RECOVERY BAND (HZ)</th></tr>
<tr><td>No contingency event or load event</td><td>49.75 – 50.25
49.85 – 50.15[2]</td><td colspan="2">49.85 – 50.15 within 5 minutes</td></tr>
<tr><td>Generation event, load event or network event</td><td>48.0 – 52.0</td><td colspan="2">49.85 – 50.15 within 10 minutes</td></tr>
<tr><td>Separation event</td><td>47.0 – 55.0</td><td>48.0 – 52.0
within 2 minutes</td><td>49.85 – 50.15
within 10 minutes</td></tr>
<tr><td>Protected event</td><td>47.0 – 55.0</td><td>48.0 – 52.0
within 2 minutes</td><td>49.85 – 50.15
within 10 minutes</td></tr>
<tr><td>Multiple contingency event</td><td>47.0 – 55.0
(reasonable endeavours)</td><td>48.0 – 52.0
within 2 minutes
(reasonable endeavours)</td><td>49.85 – 50.15
within 10 minutes
(reasonable endeavours)</td></tr>
</table>

Note: 2. 99% of the time.

Note: A generation event is commonly interpreted to mean: a credible contingency event relating to the failure or disconnection, of a generating unit of more than 50 MW. Note that the definition of a generation event in the FOS for Tasmania is worded slightly differently as: "a *synchronisation* of a *generating unit* of more than 50 MW or a *credible contingency* event in respect of either a single *generating unit* or a *transmission element* solely providing *connection* to a single *generating unit*, not arising from a *network event*, a *separation event* or a part of a *multiple contingency event*."

Note: A load event in the FOS for Tasmania is defined differently as: "either an identifiable increase or decrease of more than 20 MW of customer load (whether at a *connection point* or otherwise), or a rapid change of flow by a *high voltage* direct current interconnector to or from 0 MW for the purpose of starting, stopping or reversing its power flow, not arising from a *network event*, a *generation event*, a *separation event* or a part of a *multiple contingency event*." This is interpreted to mean an identifiable increase or decrease of more than 20 MW of customer load or a rapid change of flow by a high voltage DC interconnector to or from 0 MW for the purpose of starting, stopping or reversing its power flow.

Note: A network event may include "the unexpected *disconnection* of one major item of *transmission plant* (e.g. *transmission line*, *transformer* or *reactive plant*) other than as a result of a three-phase electrical fault anywhere on the *power system*." as described in Clause 4.2.3(b)(2) of the NER.

A.2.4 Extreme frequency excursion tolerance limit

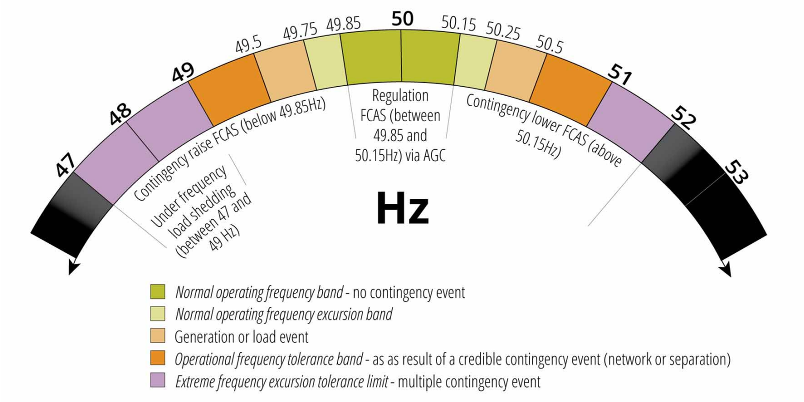
The extreme frequency excursion tolerance limit sets the upper and lower limits within which generation and network elements are expected to be able to operate.[108] If the power system frequency exceeds this limit it is considered to be an abnormal condition, and automatic protection mechanisms commence activation to disconnect network and generation elements to limit equipment damage.

Figure A.1 and Figure A.2 display frequency settings defined by the frequency operating standard for the Mainland NEM and Tasmania respectively. These figures display the frequency bands for normal operation, along with the operating bounds that apply in the

108 Schedule 5.1.3 of the NER states that "A Network Service Provider must ensure that within the extreme frequency excursion tolerance limits all of its power system equipment will remain in service unless that equipment is required to be switched to give effect to manual load shedding in accordance with clause S5.1.10, or is required by AEMO to be switched for operational purposes or is required to be switched or disconnected for operation of an emergency frequency control scheme".

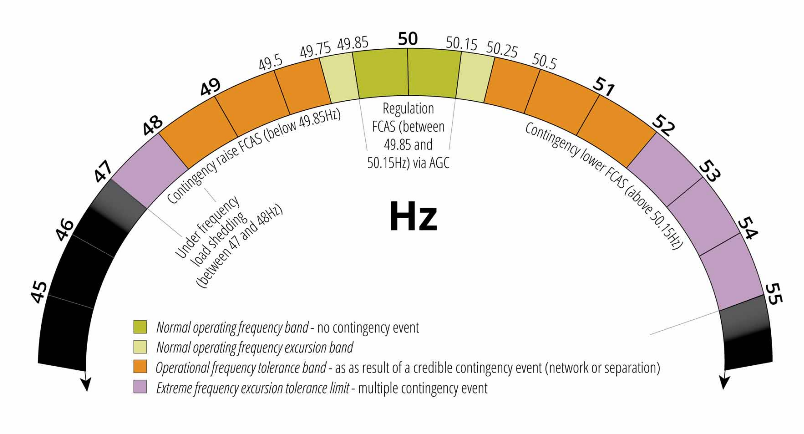
event of contingency events. The figures also show the frequency ranges within which FCAS and under-frequency load shedding schemes will operate.

Figure A.1: Frequency bands — Mainland NEM



Source: AEMC Reliability Panel

Figure A.2: Frequency bands — Tasmania



Source: AEMC Reliability Panel

The operational frequency tolerance band for Tasmania at 48 – 52 Hz is wider than that for the mainland NEM at 49 – 51 Hz. This is due to the wider tolerance of Tasmanian generators to frequency variations and the intention at the time the standard was set to limit the cost of FCAS procurement.[109]

109 This issue was discussed by the Panel in its determination of the Tasmanian FOS, where the Panel stated that "aligning the Tasmanian frequency operating standards with those that apply on the NEM mainland would be significantly more difficult, and costly, […] due to the very large quantities of contingency FCAS that would be required. Such large quantities of FCAS are unlikely to be available at a reasonable cost in Tasmania for the foreseeable future. Therefore, the Panel did not consider aligning the Tasmanian frequency operating standards with those of the NEM mainland as appropriate." Reliability Panel, December 2008, *Tasmanian Frequency Operating Standard Review* – Final Report, pp. 17-18. For similar reasons the FOS for Tasmania also includes a limit on the maximum generation contingency size of 144 MW. Ibid. p. 22.

Similarly, the upper end of the extreme frequency tolerance band of 47 – 55 Hz is significantly higher for Tasmania than the 52 Hz in the mainland NEM. Again this is related to the wider tolerance of Tasmanian generators to frequency variations.

A.3 Accumulated time error

Historically, certain clocks operated as synchronous machines, relying on an accurate power system frequency in order to measure time accurately. These synchronous clocks were common between 1940 and 1980.[110] Synchronous clocks are sensitive to power system frequency and after a period of low system frequency will read time as "slow" when compared to a reference time such as Coordinated Universal Time.[111]

In order to correct this time error, AEMO runs the power system marginally faster than the nominal frequency for a period of time to reduce the accumulated time error. AEMO operates the system to limit the accumulated time error subject to a maximum level defined in the FOS. The existing accumulated time error limits are:

- 15 seconds for the mainland NEM
- 15 seconds for Tasmania.

110 From 1980 onwards the quartz method of time keeping largely replaced synchronous clocks. Some consumer electronic appliances, such as ovens, still use the power system frequency to keep time.

111 Coordinated Universal Time or UTC is the current international standard for time keeping.

B WHAT IS POWER SYSTEM FREQUENCY AND FREQUENCY CONTROL

This appendix provides an overview of power system frequency in modern electricity networks and the mechanisms by which frequency is controlled by system operators to maintain a secure system. The appendix consists of the following sections:

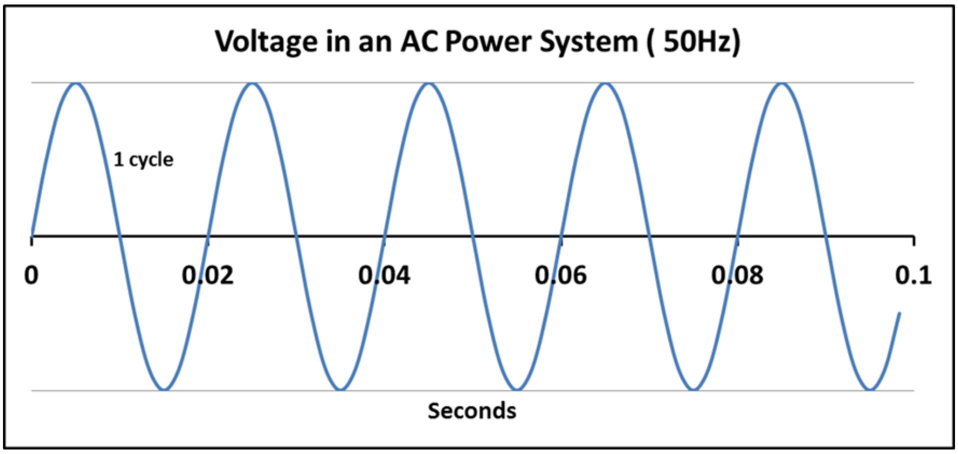
- Appendix B.1 — What is power system frequency?
- Appendix B.2 — What is frequency control?
- Appendix B.3 — Definition of contingency events.

B.1 What is power system frequency?

The NEM, like most modern power systems, generates and transfers electricity via an alternating current (AC) power system.[112]

In an AC power system, voltage oscillates between negative and positive charge at a given rate. This can be represented by the following wave diagram, which shows how voltage shifts from positive to negative over a specific time. The number of complete cycles that occur within one second is called the "frequency" and is measured in Hertz (Hz).[113] The voltage waveform corresponding to a frequency of 50 Hz is shown in Figure B.1.

Figure B.1: Voltage in an AC power system



112 By way of explanation, electrical power can be transferred by means of direct current (DC) or alternating current (AC). In a DC system the direction of current flow is constant, whereas in an AC system the direction of current flow periodically reverses. The power transfer in an AC system occurs through the oscillation of electrons in the transmission and distribution system, rather than through the direct movement or "flow" of electrons.

113 The term "Hertz" is the international standard unit for frequency named after Heinrich Rudolf Hertz who was a German physicist who proved the existence of electromagnetic waves.

In Australia all generation, transmission, distribution and load components connected to the power system are standardised to operate at a nominal system frequency of 50 Hz.[114]

This frequency is directly related to the operation of generating equipment. Electricity in an AC system has traditionally been produced by large generators that rotate what is effectively a very large magnet within a housing of copper wire coil. This rotating magnet (called the rotor) induces a current to flow in the static coil (called a stator).

The speed at which the rotor spins in the stator corresponds to how "quickly" the oscillations between positive and negative occur.

Put another way, the speed of the frequency of an AC system corresponds to the speed of rotation of generators. This is described in Box 4, which explains the basic operation of an AC induction generator.

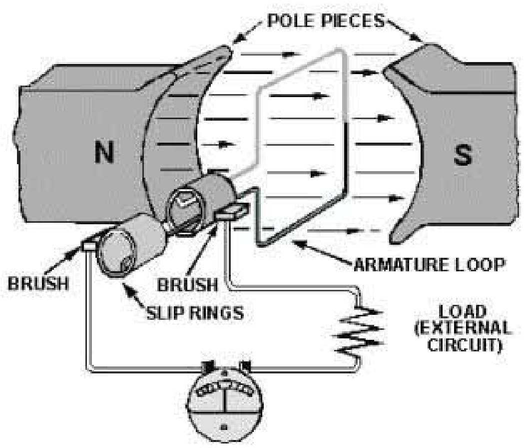
BOX 4: PRINCIPLES OF AC POWER GENERATION

A basic AC generator produces electricity by the interaction of loops of copper wire and a magnetic field. The term "armature", refers to the electrical components that produce the output power. In order to generate electricity either the armature or the magnet can be rotating, depending on the specific generator design.

To understand the basic principles of AC generation it is useful to consider a generator comprised of a single rotating armature loop, the rotor, within a stationary magnetic field produced by the stator. This arrangement is shown in Figure B.2. In this arrangement, the armature is connected to an electric circuit, and any loads (such as lights and motors) via slip rings and brushes.

114 Other power systems operate at different standard frequencies; for example the nominal power system frequency in the United States and Canada is 60 Hz, while Europe and the United Kingdom operate their power systems at 50 Hz.

Figure B.2: Basic AC generator assembly



Source: Naval Education and Training Professional Development and Technology Center, 1998, *Source: Navy Electricity and Electronics Training Series Module 5*Source: —Introduction to Generators and Motors, NAVEDTRA 14177. Sourced at: https://maritime.org/doc/neets/mod05.pdf, 16 May 2017.

As the generator windings rotate within the magnetic field, a voltage is induced in the windings along with the associated electric circuit. Figure B.3, displays how as the armature loop is rotated clockwise, its position and movement within the magnetic field produce the voltage wave corresponding to an AC power source.

Point A

The armature loop is perpendicular to the magnetic field. The windings in the armature loop are moving parallel to the field and the resultant voltage is zero.

Point B

The armature loop is aligned to the magnetic field. The windings in the armature loop are cutting through the field and the resultant voltage is a maximum positive value.

Point C

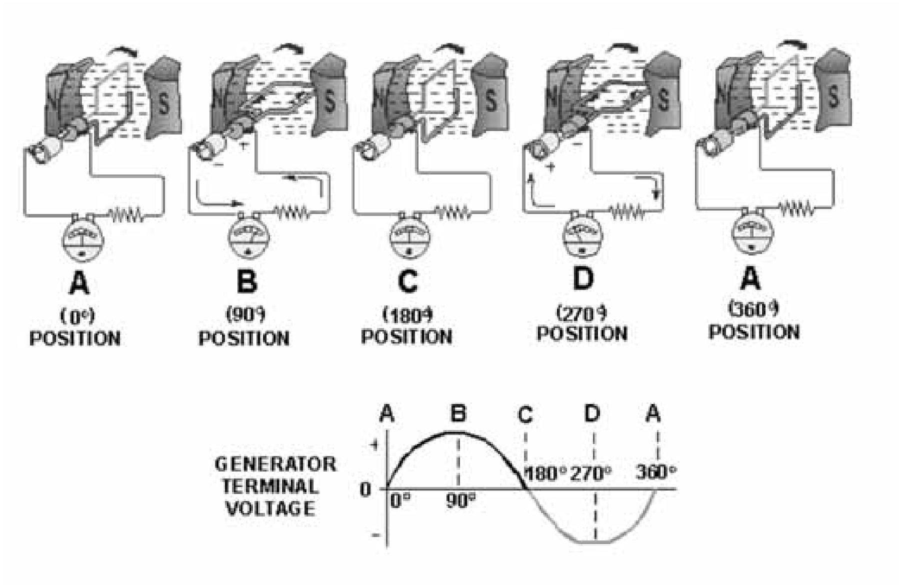
The armature loop is perpendicular to the magnetic field. The windings in the armature loop are moving parallel to the field and the resultant voltage is zero.

Point D

The armature loop is aligned to the magnetic field. The windings in the armature loop are cutting through the field and the resultant voltage is a maximum negative value.

After a complete revolution the armature loop returns to the position A and the resultant voltage returns to zero.

Figure B.3: Function of a basic AC Generator



Source: Ibid.

In the NEM, the standard frequency of the power system of 50 Hz corresponds to basic two pole generator rotating at a speed of 3000 rpm.

Note: While the above example is useful in explaining the basic principles of AC power generation, it is important to recognise that most synchronous AC generators in power systems employ a rotating electro-magnet within a stator housing comprised of the armature windings. The principle of operation is the same as for the rotating armature machine, however this arrangement avoids moving parts in contact with the output circuit and is able to create much higher voltages which is beneficial for the transmission of the electricity produced. While these examples show a single two, pole magnet and a pair of armature windings, in reality there may be many magnet poles and winding loops depending on the specific generator design.

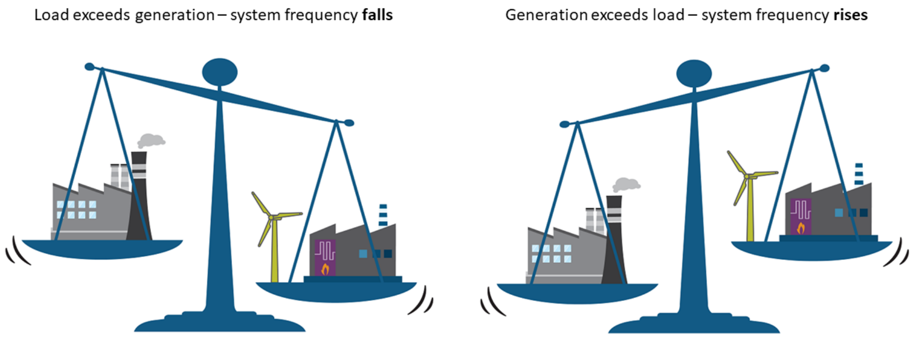
These basic operating principles of electrical generators explain how power system frequency is directly related to the rotational speed of the synchronous machines connected to the system.[115] As the frequency varies up or down so the rotational speed of synchronous machines, such as generators, also varies.

B.1.1 Frequency variation

In an operating power system, the frequency varies whenever the supply from generation does not precisely match customer demand. Whenever total generation is higher than total energy consumption the system frequency will rise and vice versa. This relationship between balancing generation and load and the power system frequency is shown in Figure B.4.

115 Synchronous generators have rotors that are directly electro-mechanically linked to the power system and spin at a speed that corresponds to the frequency of the power system.

Figure B.4: Effect of power system load and generation imbalance



This frequency variation is similar to how a car behaves when it begins to climb a hill after driving along a flat road. In order to maintain a constant vehicle and engine speed as the car climbs the hill, the engine power must be increased to balance the increased"load". If this does not take pace the car will slow down. In this basic example, the engine power is increased by depressing the accelerator pedal which supplies more fuel to the engine to maintain the vehicle speed.

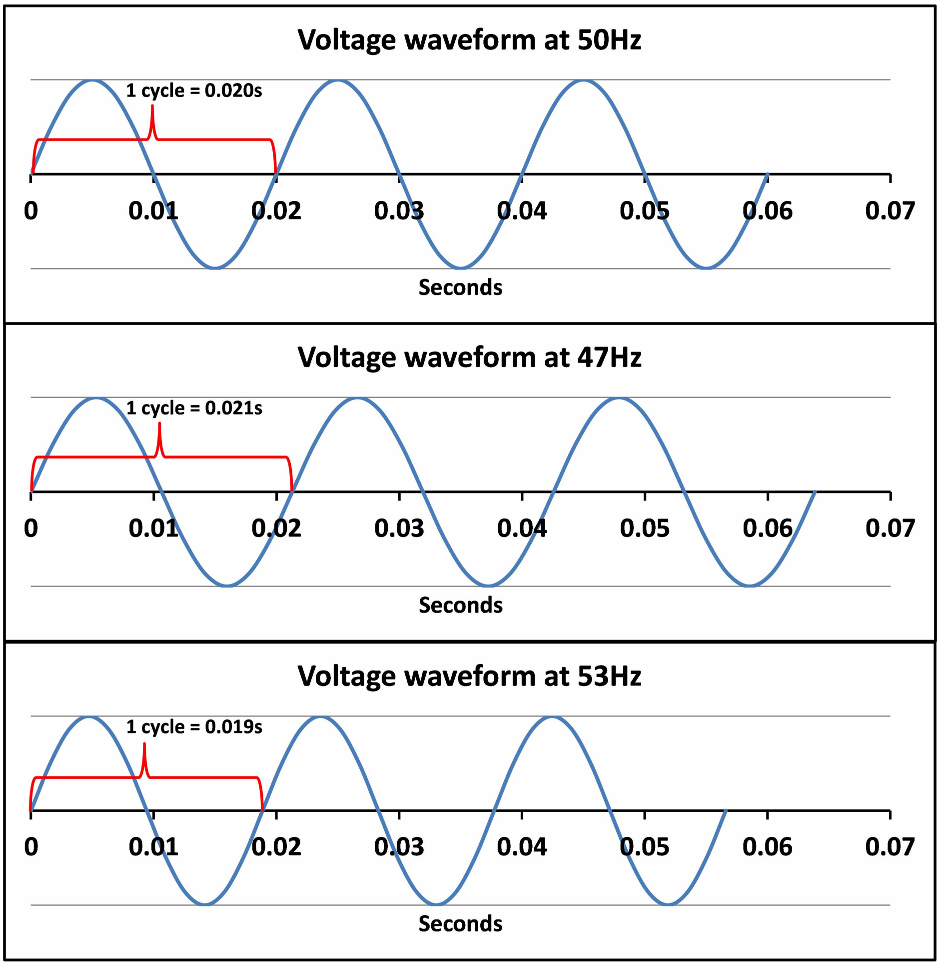
In a similar way, the power system frequency is also affected by changes in customer demand, or load, relative to the amount of available generation. To maintain the"speed" of the frequency following an imbalance of generation relative to load (analogous to the car beginning to climb the steepening hill), more energy is required from all generators (depressing the accelerator pedal) to maintain the system frequency at 50 Hz.

Figure B.5 illustrates how this increase or decrease in frequency is related to the relative shortening or lengthening of the voltage waveform. This shortening or lengthening reflects changes in the balance between supply and demand.

- The first panel shows that for a frequency of 50 Hz supply and demand are balanced and a full cycle of voltage oscillation takes 0.020 seconds to complete.
- In the second panel where the frequency has fallen to 47 Hz, demand has exceeded supply. The time taken to complete a single cycle has lengthened to 0.021 seconds.
- In the final panel, where the frequency has risen to 53 Hz, supply has exceeded demand. The time taken to complete a single cycle has shortened to 0.019 seconds.

This variation of plus or minus 6% between the different cases illustrated in each panel may seem small, however, the corresponding change in rotational speed of asynchronous generator spinning at 3000rpm is in the order of plus or minus 180rpm. Such deviations could have significant impacts on the functional efficiency and potentially the safety of this equipment. The impact of frequency deviations on power system equipment is discussed further in appendix B.2.

Figure B.5: Power System Frequency Variations



In the majority of situations the changes in supply and demand that cause these changes in frequency are such that the corresponding variations in frequency are very small. Household appliances and industrial load being switched on and off are all examples of minor changes in demand happening all the time. The generation supplied into the network may also change due to the variable output of wind and solar generation.[116]

If the combined change in supply or demand is large enough the frequency of the power system may diverge materially from 50 Hz. In response to small changes in frequency, power

116 In practice AEMO forecasts the expected demand and the output of variable renewable generation as part of their operation of the wholesale electricity market. Operationally, minor frequency deviation can be a result of actual demand or generation output varying from the demand or generation output as forecast. This forecast error issue has been raised in AEMO's *Engineering Framework*.

stations shift output ever so slightly to compensate, thereby maintaining the frequency within normal operating levels.

On occasion, changes in supply and demand can be more significant. Large generating units and transmission lines may trip unexpectedly and suddenly stop producing or transmitting electricity. Similar outcomes can occur on the demand side, if large industrial facilities trip off the system and suddenly stop consuming. These are referred to in the NER as contingency events. They are less common but tend to result in more significant changes in system frequency.

B.2 What is frequency control?

As discussed in appendix B.1, the electricity in the NEM is supplied by an alternating electric current that oscillates at or close to 50 Hz. To maintain the safe, secure and reliable operation of the power system, this frequency is controlled within narrow bands that are related to the broader system conditions.

B.2.1 Why do we need to control frequency?

All equipment connected to the power system is designed to operate at or near the nominal frequency of 50 Hz.[117] The tolerance of different machines or devices to frequency deviations varies both in terms of the size of a divergence that can be withstood and the length of time that the deviation can be ridden through, for example, gas and steam turbines connected to synchronous generating units are particularly sensitive to frequency deviations. Synchronous rotating machinery such as steam and gas turbines used for power generation are finely tuned for operation at the specific system frequency and are prone to reduced efficiency and even damage during operation away from their design speed. Such conditions may cause equipment damage due to abnormal current flows within the electrical windings and cavitation and vibration affecting the turbine blades.

A typical steam turbine can operate continuously at ±1% away from the nominal frequency, or within a range of 49.5 – 50.5 Hz. The same steam turbine is only designed to withstand short periods of operation further away from the nominal frequency with a practical working limit reached at around ±5% or 47.5 – 52.5 Hz.[118] Outside this operating frequency range the turbine may experience damaging vibrations and if allowed to operate at an excessively high speed there is risk of a catastrophic equipment failure.

As a self-protection mechanism, generation and transmission equipment are designed to disconnect from the power system during periods of prolonged or excessive deviations from the nominal system frequency. However, the disconnection of generation due to low system frequency would act to worsen the supply-demand imbalance that originally caused the frequency disturbance and potentially lead to a cascading system failure and a major

117 This includes both synchronous generators as well as synchronous loads (large spinning machinery such as electric motors). Also includes network equipment, non-synchronous generation and customer equipment.

118 General Electric Company, 1974, Load Shedding, *Load Restoration and Generator Protection Using Solid-state and Electro-mechanical Under-frequency Relays* — Section 4 – Protection of steam turbine – generators during abnormal frequency conditions.

blackout. Controlling frequency is therefore critically important to maintaining a secure and reliable power system.

Most consumer electronic equipment is designed to operate within a tolerance range of ±5% away from the nominal frequency, or 47.5 – 52.5 Hz. This is the case for computer systems, printers, VCRs, TVs, photocopiers, communications equipment, variable speed drives for electric motors, switch mode power supplies, and high-efficiency lighting.[119]

In summary, the adverse impacts of excessive frequency deviation include, in order of increasing severity:

- error or malfunction of consumer equipment
- increased wear and tear on synchronous generation equipment
- automatic disconnection of generation equipment potentially leading to a cascading failure and major blackout
- catastrophic failure of synchronous generation equipment, potentially leading to a cascading failure and major blackout.

B.2.2 How is frequency controlled?

To maintain a stable system frequency, the supply of electricity into the power system must balance the instantaneous consumption of electricity at all times. As discussed in appendix B.1, this balance between supply and demand is directly related to the frequency of the power system. When there is more generation than load, the frequency will tend to increase. When there is more load than generation, the frequency will tend to fall.

One of AEMO's primary operational objectives is to maintain the frequency of the power system by balancing supply and demand. AEMO operates the wholesale electricity market which dispatches electricity generation to meet the expected demand for electricity every five minutes. Some imbalance between supply and demand is expected to occur within the five-minute dispatch process; these imbalances are managed through a market for regulation FCAS.

AEMO coordinates the FCAS markets, which enables generation to be increased or decreased at short notice to restore the power system balance.[120] The FCAS market includes the procurement of contingency services that provide AEMO with the ability to manage the power system frequency in response to the failure of a single generating unit or major transmission element, referred to as a credible contingency event.[121] The arrangements for FCAS are discussed further in appendix C.2.

In the event that insufficient FCAS is available to manage the risk of a credible contingency event, AEMO may use other means to maintain the secure operation of the power system.

119 National Electricity Code Administrator, 1999, *Reliability Panel Frequency Standards Consultation Paper*, Appendix 3 – University of Wollongong, Review of National Frequency Standards from a Customer's Perspective.

120 FCAS markets are coordinated by AEMO to be able to respond to and correct frequency deviations as a result of errors in demand forecast, generation output or due to credible contingencies such as the loss of any single generation or transmission element. FCAS may take the form of fast response reserve generation capacity or controlled loads, such as major industrial loads.

121 Clause 4.2.3 (b) of the NER — A credible contingency event means a contingency event the occurrence of which AEMO considers to be reasonably possible in the surrounding circumstances including the technical envelope.

Alternative methods include the pre-emptive constraining of interconnector flows or generation output to reduce the size of the possible contingency event and/or provide additional reserve capacity to be available to respond to a contingency event.[122] System security and contingency events are described further in appendix B.3.

AEMO also coordinates a range of emergency frequency control schemes as to address more substantial frequency deviations that result from more severe contingency events. These schemes operate to rapidly disconnect load or generation in order to rebalance the power system and restore the frequency. The operation of EFCS is discussed further in appendix C.3.

B.3 Definition of contingency events

A key factor in maintaining system security is the definition of contingency events, which are events that involve "the failure or removal from operational service of one or more generating units and/or transmission elements."[123] Such events may lead to a temporary imbalance between generation and load in the power system and a corresponding deviation of the power system frequency. The classes of contingency event defined for the NEM are described in Box 5.

BOX 5: CONTINGENCY EVENTS

The NER includes three different classes of contingency event:

- credible contingency events
- non-credible contingency events
- protected events.

A **credible contingency** event, illustrated in Figure B.6**,** is an event that AEMO considers is reasonably likely to occur in the surrounding circumstances. Examples of credible contingency events include the unexpected disconnection of one operating generating unit or the unexpected disconnection of one major transmission plant, such as a transmission line or transformer.114 For a credible contingency event, AEMO must operate the power system and procure sufficient responsive generation and load capacity to enable the power system to be rapidly rebalanced following the event. This includes the requirement that, following the event, the power system will return to a satisfactory operating state in accordance with the relevant frequency bands and recovery times defined in the FOS. This responsive generation or load is provided through the FCAS market arrangements.

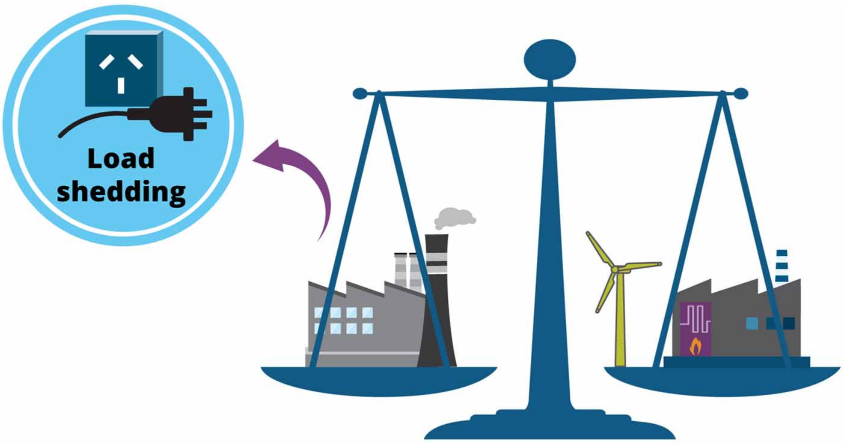
122 AEMO, 2022, *Power System Security Guidelines*, pp.12-14.

123 Clause 4.2.3(a) of the NER — Credible and non-credible contingency events and protected events.

Figure B.6: Credible contingency events

A **non-credible contingency** event, illustrated in Figure B.7, is any contingency event that is not a credible contingency event, such as the simultaneous failure of multiple generating units or transmission elements. For a non-credible contingency event, AEMO coordinates EFCS that enable load or generation to be progressively and automatically disconnected to "significantly reduce the risk of cascading outages and major supply disruptions".

Figure B.7: Non-credible contingency



A **protected** event, is special category of non-credible contingency that is declared by the Reliability Panel, on the advice of AEMO. A protected event is a high consequence, low likelihood event for which the Panel assesses the costs of mitigating the risks of the event are in the long term interest of consumers in accordance with the NEO. For a protected event AEMO may use a combination of market mechanisms and EFCS to return the power system to a satisfactory operating state in accordance with the relevant frequency bands and recovery times defined in the FOS.

Figure B.8: Protected event

Source: Clause 4.2.3 of the NER — Credible and non-credible contingency events and protected events.
Source: Clause 4.2.6(c) of the NER — General principles for maintaining power system security.
Source: Clause 8.8.4(e) of the NER — Determination of protected events.

C NEM FREQUENCY CONTROL FRAMEWORKS

This appendix provides an overview of the NEM frequency control frameworks and the mechanisms by which the frequency is controlled. This appendix consists of the following sections:

- Appendix C.1 — AEMO's responsibility for maintaining the secure operation of the power system
- Appendix C.2 — the role of frequency control ancillary services in regulating the power system frequency
- Appendix C.3 — the role of emergency frequency control schemes
- Appendix C.4 — how the FOS relates to the technical performance standards for generators and networks.

C.1 AEMO's responsibility for managing frequency and power system security

An operational power system must be able to operate satisfactorily under a range of operating conditions including in the event of foreseeable contingency events, such as the failure of a single transmission element or generator. In the NEM, AEMO is responsible for maintaining the power system in a "secure operating state" by satisfying the following two conditions:

1. The system parameters, including frequency, voltage and current flows are within the operational limits of the system elements, referred to as a "satisfactory operating state"
2. The system is able to recover from a credible contingency event or a protected event, in accordance with the power system security standards.[124]

Frequency control is a key element of power system security. This is reflected in the NER definition of a "satisfactory operating state", which includes a direct reference to the frequency bands defined in the FOS:[125]

> The power system is defined as being in a satisfactory operating state when:
>
> the frequency at all energised busbars of the power system is within the normal operating frequency band, except for brief excursions outside the normal operating frequency band but within the normal operating frequency excursion band.

AEMO is primarily responsible for maintaining the power system in a "secure operating state" which includes managing the power system frequency in accordance with the FOS.

124 Clause 4.2.4(a) of the NER — Secure operating state and power system security.

125 Clause 4.2.2 (a) of the NER — Satisfactory Operating State.

C.2 Frequency control ancillary services (FCAS)

During normal operation of the power system AEMO uses FCAS to control the power system frequency in accordance with its system security responsibilities described in appendix C.1. FCAS allows for imbalances of supply and demand to be corrected by arresting most frequency fluctuations and restoring system frequency to 50 Hz (the normal operating frequency band) within the time frames specified in the FOS.

These services include:

- regulating raise and lower services to manage small frequency deviations during normal operation of the system
- contingency raise and lower services to respond to large frequency deviations following specific events that occur outside the normal operation of the system.

C.2.1 Regulation FCAS: frequency control during normal operation

The power system frequency is continually fluctuating in response to changing generation and load conditions. To manage this fluctuation, AEMO's automatic generation control (AGC) system continuously monitors the power system frequency and sends out "raise" or "lower" signals to the registered generators and loads that are dispatched to provide FCAS to correct the small frequency deviations. These correcting services are called regulating FCAS, as they regulate the power system frequency to keep it within the normal operating frequency band defined in the FOS.[126] They include:

- The **regulating raise service** is the service of either increasing generation or decreasing load in response to electronic raise signals from AEMO.[127]
- The **regulating lower service** is the service of either decreasing generation or increasing load in response to electronic lower signals from AEMO.[128]

C.2.2 Contingency FCAS: frequency control following unexpected events

Contingency FCAS is procured by AEMO to respond to larger deviations in power system frequency, that are usually the result of contingency events such as the tripping of a large generator or load. AEMO procures contingency response services through the FCAS markets, providers of contingency FCAS respond automatically to deviations in the power system frequency outside of the normal operating frequency band.[129] Contingency FCAS is divided into raise and lower services at six different speeds of response and sustain time:

- The **fast raise service**, commonly referred to as 6-second raise FCAS, is the service of a rapid increase in generation or decrease in load in response to electronic raise signals from AEMO.

126 Clause 3.11.2 of the NER — Market Ancillary services.

127 AEMO, December 2021, *Market Ancillary Services Specification*, p.13.

128 Ibid.

129 The provider of contingency FCAS responds automatically based on a local measurement of system frequency, in comparison to regulating FCAS which is coordinated by AEMO based on a centralised measurement of system frequency. During normal operation the power system frequency is consistent throughout the network, however following sudden contingency events there can be transient variations in frequency as the power system reacts.

- The **fast lower service**, commonly referred to as 6-second lower FCAS, is the service of a rapid decrease in generation or increase in load in response to electronic raise signals from AEMO.
- The **slow raise service**, commonly referred to as 60-second raise FCAS, is the service of an increase in generation or decrease in load in response to electronic raise signals from AEMO.
- The **slow lower service**, commonly referred to as 60-second lower FCAS, is the service of a decrease in generation or increase in load in response to electronic raise signals from AEMO.
- The **delayed raise service**, commonly referred to as 5-minute raise FCAS, is the service of a delayed increase in generation or decrease in load in response to electronic raise signals from AEMO.
- The **delayed lower service**, commonly referred to as 5-minute lower FCAS, is the service of a delayed decrease in generation or increase in load in response to electronic raise signals from AEMO.[130]

In response to a contingency event, each type of FCAS works together to recover the power system frequency within the applicable frequency bands and time frames defined in the FOS. The initial rate of change of frequency is determined by the contingency size and the inertia of the power system. Following the contingency event, the falling system frequency is arrested and restored by automatic primary frequency control response, provided by:

- generating units that have their governors or inverters set to increase their generation output in response to changes in system frequency in compliance with the mandatory PFR rule[131]
- generators who are able to quickly increase their generation output and are enabled to provide fast raise (6 second) contingency FCAS.

The system frequency is then stabilised by the slow raise FCAS and finally recovered to the normal operating band by utilisation of delayed raise FCAS and the subsequent dispatch of additional generation in the next dispatch interval.

C.2.3 FCAS markets

The individual providers of each of the eight types of FCAS at any one time are determined by the operation of the FCAS markets. In order to participate in the FCAS market, market participants must register with AEMO, which includes verifying their capability to provide the services they wish to offer. The providers can then submit FCAS offers which include the price and quantity of each type of FCAS they wish to provide.[132]

130 Ibid., p.12.

131 A governor is a device that regulates the speed of a machine, such as a generating unit. A governor incorporated as part of a generating system provides the capability to control the electrical output of the generator. The governor can be enabled to provide an increase or decrease in generation output in response to changes in the power system frequency. This response is determined by the governor droop and deadband settings.

132 AEMO, November 2021, *Guide to Ancillary Services in the National Electricity Market*, p.8.

AEMO determines the amount of FCAS required to manage the power system frequency in accordance with the FOS. For each 5-minute dispatch interval the national electricity market dispatch engine (NEMDE) enables sufficient FCAS in each market and the price for each service is set by the highest enabled bid in each case.

Providers of FCAS are paid for the amount of FCAS in terms of dollars per megawatt enabled per hour, in addition to any payments for generation or consumption through the wholesale electricity market.[133]

C.3 Emergency frequency control schemes (EFCS)

Emergency frequency control schemes are schemes that help restore the power system frequency in the event of extreme power system events such as the simultaneous failure of multiple generators and or transmission elements. The operational goal of emergency frequency control schemes is to act automatically to arrest any severe frequency deviation prior to breaching the extreme frequency excursion tolerance limit and hence avoid a cascading failure and widespread blackout.

Traditional emergency frequency control schemes operate via frequency sensing relays that detect a frequency deviation beyond a pre-defined set point and act to disconnect any connected generation or load behind the relay. However, schemes can be set up to operate based on the occurrence of a particular contingency event, such as the failure of an interconnector or may act in response to an excessive rate of change of frequency. The installation and operation of emergency frequency control schemes is the responsibility of the relevant transmission network service provider (TNSP), while AEMO coordinates the overall performance of the schemes as part of its system security responsibility.

Emergency frequency control schemes can be divided into three categories depending on their operational characteristics:

- Automatic under-frequency load shedding
- Over frequency generation shedding schemes
- Protected event EFCS.

C.3.1 Automatic under-frequency load shedding

In the event of a sudden and unexpected failure of a large amount of generation, FCAS may not be able to operate fast enough and the power system frequency will quickly fall. To arrest the dropping frequency automatic load shedding schemes are set up to disconnect load blocks and rebalance the power system supply and demand. These schemes commence operation when the power system frequency drops below the lower limit of the operational frequency tolerance band (49 Hz for the mainland NEM and 48 Hz for Tasmania). The scheme settings are staggered between the lower limit of the operational frequency tolerance band and 47 Hz which is the lower limit of the extreme frequency excursion tolerance limit for the mainland NEM and Tasmania.[134]

133 Ibid., pp.10-11.

134 Clause 4.3.5(a) of the NER — Market customer obligations.

C.3.2 Over frequency generation shedding schemes

Over-frequency generation shedding schemes are a particular type of emergency frequency control scheme that are used in the NEM to protect against over-frequency events. An over-frequency event is most likely to occur as the result of a separation event that leads to an excess of generation in the resultant islanded region.

Regions with limited interconnection to the rest of the NEM and a high ratio of domestic generation relative to domestic demand are particularly vulnerable to an over-frequency event. This is because of the potential consequences of an interconnector trip separating the region from the rest of the NEM. If this trip occurs while the interconnector is at full export capacity, this could result in a major supply and demand imbalance within the region. This could in turn cause frequency to rise very rapidly, potentially tripping generation in the region and causing a cascading outage and potentially a black system. [135]

Over-frequency schemes are therefore more valuable in those regions with a greater chance of separation. The Panel notes that such mechanisms already exist to limit the consequences of over-frequency in Tasmania and South Australia.[136]

C.3.3 Protected event EFCS

The declaration of a protected event by the Reliability Panel may include the specification of a new or modified EFCS; such an EFCS is defined by the NER as a protected event EFCS.[137]

A protected event EFCS is a specialised protection scheme designed to mitigate the impacts of a non-credible contingency event that has been declared to be a protected event. The technical parameters for the scheme are defined by the "target capabilities" which form part of the protected event EFCS standard. These "target capabilities" include:[138]

> For an emergency frequency control scheme means the technical parameters required to define the intended (but not guaranteed) service provided by the scheme which may include:
>
> (a) power system conditions within which the scheme is capable of responding;
>
> (b) the nature of the scheme's response (load shedding or generation shedding for the purposes of managing frequency);
>
> (c) the speed of the response;
>
> (d) the amount of load shedding or generation shedding that may occur when the scheme responds; and
>
> (e) capability to dynamically sense power system conditions.

135 AEMC, *Emergency Frequency Control Schemes*, Final Determination, March 2017, pp.69-70.

136 AEMO, *South Australia — operation as a viable island,* June 2018, p.11.

137 Clause 8.8.4(g) of the NER — Determination of Protected Events.

138 Chapter 10 of the NER definition — target capabilities.

C.4 Generator and network performance standards

The FOS defines elements of the performance standards that apply to generator and network equipment in the NEM. The NER performance standards define the level of performance required of the equipment that make up, and is connected to, the NEMpower system. Power system equipment must comply with these standards to enable AEMO to effectively manage the system security.

For example, the performance standards include specification of the ability of a generating unit to ride through a disturbance on the power system. If all generators adhere to these standards, a power system incident is less likely to lead to a cascading failure and endanger power system security.

The FOS defines the elements of these performance standards that relate to response and the ability to withstand frequency variations. The performance standards include specific frequency performance requirements that refer to the settings in the FOS:

- Network performance requirements — 5.1 of the NER
- Conditions for the connection of generators — Schedule 5.2 of the NER
- Conditions for connection of Market Network Services — Schedule 5.3a of the NER.

C.4.1 Network performance requirements

The performance standards that apply to network equipment include the requirement that: within the extreme frequency excursion tolerance limits defined in the FOS, all network equipment will remain in service unless that equipment is required to give effect to manual load shedding or the activation of an emergency frequency control scheme.[139]

Similarly, market network services, such as Basslink which operates as a merchant interconnector, must be capable of continuous uninterrupted operation while the power system frequency is within the range defined in the FOS.[140]

C.4.2 Conditions for the connection of generators

The performance standards for the connection of generators include requirements for the response of a generator unit to frequency disturbances and requirements for frequency control functionality of generator equipment.[141]

The specification of the settings in the FOS for the operational frequency tolerance band aligns with the widest setting for the containment of system frequency following a credible contingency event, be that a generation event, a load event, a network event or a separation event. For example, during interconnected operation, the Operational frequency tolerance band is specified as 49.0 - 51.0 Hz in the mainland and 48.0 - 52.0 Hz for Tasmania. During

139 S5.1.3 of the NER— Frequency Variations.

140 S5.3a.13 of the NER — Market network service response to disturbances in the power system.

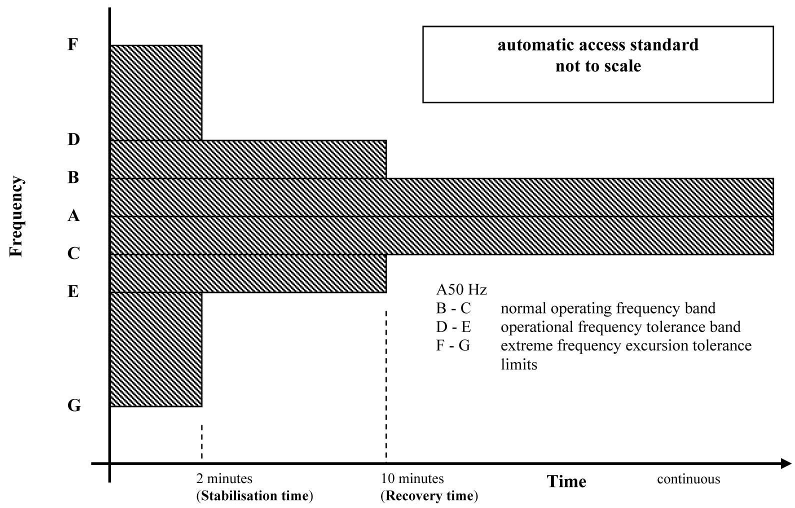
141 This section summarises the requirements in the NER that apply to generators connected after the 8 March 2007, when the National Electricity Amendment (Technical Standards for Wind Generation and other Generator Connections) Rule was made. Chapter 11 of the NER contains a transitional rule, Clause 11.10.3 that allows for pre-existing access standards to continue to apply.

supply scarcity in the mainland NEM, the Operational frequency tolerance band is specified as 48.0 - 52.0 Hz.

These technical performance standards were included in the NER in 2007 trough the *Technical Standards for Wind Generation and other Generator Connections Rule 2007* and updated in 2018 through the *Generator technical performance standards rule 2018*. The 2018 change amended the access standards in clause S5.2.5.3 to include additional RoCoF withstand requirements (±3 Hz/s for more than 1 second in the automatic access standard, and ±2 Hz/s for more than 250 ms in the minimum access standard, or such other range as determined by the Reliability Panel from time to time).[142]

Figure C.1 and Figure C.2 describe the automatic and minimum access standards, respectively, for the connection of generators with respect to response to frequency disturbances.

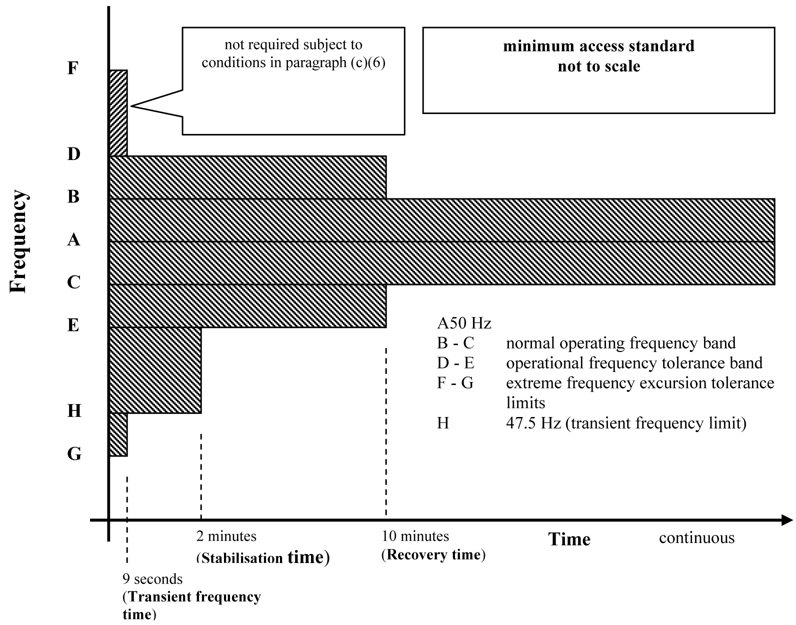
Figure C.1: Generator automatic access standard



Source: S5.2.5.3 of the NER — Generating system response to frequency disturbances.

142 AEMC, *Generator technical performance standards* - Final Determination, 27 September 2018, p.226.

Figure C.2: Generator minimum access standard



Source: Ibid.