AEMO Advice: Reliability Panel Review of Frequency Operating Standard

December 2022

National Electricity Market

Important notice

Purpose

This document contains AEMO's advice to the Reliability Panel on its 2022 review of the frequency operating standard for the National Electricity Market under clause 8.8.1(a)(2) of the National Electricity Rules.

This document is based on information available to AEMO up to 30 September 2022 unless otherwise indicated.

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Terms and acronyms

This document uses many terms that are defined in the National Electricity Rules, and are intended to have the same meanings. Frequently used abbreviations are listed at the end of this document.

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

Executive summary

The Reliability Panel is responsible for reviewing the frequency operating standard (FOS) for the National Electricity Market (NEM) on advice from AEMO. The last review was completed in 2019. In April 2022, the present FOS review commenced and AEMO was requested to provide advice in four key areas:

1. Frequency settings during normal operation.
2. Rate of change of frequency (RoCoF) limits.
3. Frequency settings for contingency events and contingency size limits.
4. Limits on accumulated time error.

The FOS specifies the allowable range for power system frequency and time error for the NEM mainland regions and for Tasmania. AEMO must endeavour to operate the power system so that it remains within the FOS limits. AEMO specialist teams have conducted a thorough review in each of the four areas, extending on existing research and work already underway. Frequency settings, RoCoF, contingency sizes and time error have all been the focus of previous research, existing studies and analysis.

In the transitioning power system of the NEM it is envisaged, for at least the next 10 years, that synchronous and non-synchronous technologies will have to work together in a variety of operational conditions. This will necessitate regular review of the technical limitations and operating boundaries for the NEM. In AEMO's view, it is critical that the security of the power system is effectively and efficiently maintained as the NEM interconnected power system enters an era of change, variability and uncertainty.

The FOS is no exception, and in this 2022 FOS review it will be important to recognise the changing parameters of the power system to prepare for a transitional period as we balance a move towards a high penetration renewable energy power system with retirements of traditional thermal synchronous generation.

Each of the four key FOS areas has been summarised in this Executive Summary. The Reliability Panel requests for AEMO advice are highlighted in bold followed by the AEMO advice. The detailed data, studies, modelling, rationale and justifications are in the body of the document.

Frequency performance during normal operation

The Reliability Panel has requested recommendations and rationale for:

- **The target distribution for frequency during normal operation and how this could be specified in the FOS.**
  - AEMO advises there should be no change to the parameters in the FOS for normal operation on the mainland.
- AEMO recommends, to remove all doubt, the FOS clearly states the target frequency for the NEM is 50 hertz (Hz).
- **The system security and operational implications of setting the primary frequency control band (PFCB) at a range of settings between the current 'narrow' setting of 49.985-50.015 Hz and a 'wide' setting of 49.5-50.5 Hz.**
  - AEMO advises there should be no change to the PFCB of +/- 0.015Hz for the mainland and Tasmania.

Limits on rate of change of frequency for the power system

The Reliability Panel requested **advice on the system security and operational benefits of setting limit(s) on the rate of change of frequency (RoCoF) following contingency events in the NEM, including:**

- **The technical capability of current power system plant to withstand different levels of RoCoF following contingency events.**
  - Specific details are not well known, even by the original equipment manufacturers (OEMs). It is widely accepted – by OEMs and other grid operators and from AEMO's our own observations from past events– that thermal coal- and gas-fired generators are not designed to ride through RoCoF much beyond 1 Hertz per second (Hz/s).
- **The expected capabilities and limitations of protection schemes, including automatic under-frequency load shedding (UFLS), with respect to RoCoF.**
  - Limitations and capabilities of protection schemes are dependent on the performance of the relays and circuit breakers in the networks. Typically, it is found that for RoCoF up to 2 Hz/s, protection schemes are safely able to operate in a variety of conditions, although at RoCoF levels above 3 Hz/s outcomes can be undesirable in many conditions.
- **The role that a RoCoF limit would play in the operation of the power system, including with respect to the provision of very fast FCAS and physical and synthetic inertia.**
  - A RoCoF limit set at the correct level around 1 Hz/s will prevent vulnerable generators with low withstand capability from disconnecting during credible events. This is particularly important during the transition when there is a combination of very fast-moving inverter-based resources (IBR) and synchronous, slower moving thermal plant with inherent inertia resulting in low RoCoF withstand tolerance.
  - In addition, the presence of a RoCoF standard for credible contingency events will enable a pre-contingent volume of inertia and post-contingent volume of very fast frequency control ancillary services (FCAS) to be determined. AEMO continues to research the application and benefits of physical and synthetic inertia and further work is required on this subject. Studies in Section 3.2.4 (Sensitivities to RoCoF with no Battery droop response headroom) showed that an injection of energy post the event can contribute to reducing the RoCoF.
- **How RoCoF limits are specified and the reasoning for these formatting or measurement approaches. For example, the value for RoCoF in Hz/s and the time-period over which this is measured and whether RoCoF limits should be varied for different NEM regions and different operating conditions**.

  AEMO advises for credible contingencies on the mainland:

  - The FOS should include a limit for RoCoF of 1 Hz/s, measured as not exceeding 0.5 Hz change over any 500ms averaging period.
  - AEMO recommends that the Tasmanian RoCoF for credible events be limited to +/- 3 Hz/s measured as not exceeding 0.75 Hz over any 250ms averaging period.
  - AEMO advises that the FOS should include a reasonable endeavours RoCoF limit of 3 Hz/s measured as not exceeding 0.9 Hz over any 300 milliseconds (ms) averaging period for non-credible contingency events on both the mainland and Tasmania.

  - AEMO does not recommend a RoCoF limit in the FOS for protected events. Instead, AEMO proposes that RoCoF limits for protected events be applied on a case-by-case basis during the establishment of each protected event.

Setting for contingency events

The Reliability Panel requested that AEMO provide advice on:

- **Whether the existing frequency containment and recovery bands that apply for credible generation, load and network events remain fit for purpose, in particular:**
  - Opportunities to improve the clarity and consistency of settings in the FOS for credible events.
    - No change in the contingency bands that apply for credible generation, load, and network events in the FOS.
  - **The appropriate setting for the operational frequency tolerance band that applies during conditions of supply scarcity, noting that stakeholders have suggested that the current setting of 48-52 Hz places an excessive obligation for connecting generators through the application of National Electricity Rules (NER) S5.2.5.3.**
    - AEMO confirms that the full range of 48-52 Hz in Queensland and South Australia and 48.5-52 Hz in Victoria and New South Wales is required during system restoration due to the wide range of expected frequency in system restoration conditions. AEMO also confirms that this range should continue to flow through to the standards for connecting generators. As such, AEMO advises no change to the settings for the operational frequency tolerance band that applies during conditions of supply scarcity.
    - AEMO recommends that the term “supply scarcity” be renamed “system restoration” to reduce confusion about the application of these settings.
- **Whether the existing frequency containment and recovery bands for non-credible contingency events and protected events remain fit for purpose and opportunities to improve the clarity and consistency of settings in the FOS for credible events.**
    - No change in the contingency bands that apply for non-credible generation, load, and network contingency events in the FOS.
- **The inclusion in the FOS of limits for the maximum size of credible contingency events for the Tasmanian region. This includes advice on:**
  - **Whether the existing limit of 144 megawatts (MW) for the largest allowable generation event in the Tasmanian region and system remains appropriate. This includes an assessment of the system security and operational implications of raising this limit to 155 MW, as proposed by Woolnorth Renewables.**
    - Retain the inclusion in the FOS of a maximum generation contingency limit of 144 MW for the Tasmanian region.
  - **Whether the generation limit in Tasmania should be extended to apply to network and load events. In its submission to the issues paper, TasNetworks expressed support for the application of a similar limit for the largest load event in Tasmania.**
    - A limit of 144 MW apply to all generation, load, network and separation events as defined in the FOS for Tasmania, unless a specific control scheme is in place that is able to operate effectively to manage the

contingency risk and implemented by the Tasmania network service provider (NSP) with the approval of AEMO.

- **Whether the FOS should include a limit on the maximum credible contingency event for the mainland system and whether such a limit should apply for generation, load and/or network events.**
    - The FOS should not include a limit on the maximum credible contingency event for the mainland system.

The limit for accumulated time error in the NEM

The Reliability Panel requested that AEMO provide advice on:

- **The security and operational impacts and other related learnings since the Panel's 2017 determination to increase the limit on accumulated time error in the mainland NEM from 5 seconds to 15 seconds.**
  - There are no security or operational impacts related to an increase in the FOS limit from 5 to 15 seconds for time error in the NEM mainland or on Tasmania.
- **AEMO's view on further potential reforms to the limit on accumulated time error, including consideration of potential options including:**
  - **Maintenance of the current limit on accumulated time error.**
  - **Removal of the limit on accumulated time error.**
  - **That the limit on accumulated time error apply over a period of time, rather than being an absolute limit. AEMO's advice is sought on how such a time-based limit on accumulated time error may be set. This may be informed by analysis of the rate of accumulation of time error over time in the NEM and what rate of accumulation is considered to be 'good operating practice'.**
    - AEMO's advice is that the Reliability Panel consider removing a time error limit from the FOS, recognising AEMO will still monitor and control time error as necessary.
    - AEMO is to be transparent and report to the market through the quarterly frequency reports when time error has been reset.

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1 Introduction

The frequency operating standard (FOS) for the National Electricity Market (NEM) is determined and reviewed by the Reliability Panel under the National Electricity Rules (NER). It specifies the allowable range for power system frequency and time error for the NEM mainland regions and for Tasmania. AEMO must endeavour to operate the power system so that it remains within the FOS limits.

AEMO is pleased to provide this advice to support the Reliability Panel's 2022 review of the FOS.

1.1 AEMO advice for the Reliability Panel's 2022 review

AEMO's advice is based on the system security and operational implications of potential FOS changes, with consideration given to market outcomes and the national electricity objective. AEMO has provided advice on each of the issues described in this section, as identified in the Reliability Panel's issues paper published on 28 April 2022 and its request for advice dated 12 July 2022.

1.1.1 Frequency performance during normal operation

Recommendation and rationale for:

- The target distribution for frequency during normal operation and how this could be specified in the FOS.
- The system security and operational implications of setting the primary frequency control band at a range of settings between the current 'narrow' setting of 49.985-50.015 hertz (Hz) and a 'wide' setting of 49.5-50.5 Hz.

1.1.2 Limits on rate of change of frequency for the power system

Advice on the system security and operational benefits of setting limit(s) on the rate of change of frequency (RoCoF) following contingency events in the NEM, including:

- The technical capability of current power system plant to withstand different levels of RoCoF following contingency events.
- The expected capabilities and limitations of protection schemes, including automatic under-frequency load-shedding, with respect to RoCoF.
- The role that a RoCoF limit would play in the operation of the power system, including with respect to the provision of very fast FCAS and physical and synthetic inertia.
- How RoCoF limits are specified and the reasoning for these formatting or measurement approaches. For example, the value for RoCoF in Hz/s and the time-period over which this is measured and whether RoCoF limits should be varied for different NEM regions and different operating conditions.

1.1.3 Setting for contingency events

Advice on:

- Whether the existing frequency containment and recovery bands that apply for credible generation, load and network events remain fit for purpose, in particular:
  - Opportunities to improve the clarity and consistency of settings in the FOS for credible events.

  - The appropriate setting for the operational frequency tolerance band that applies during conditions of supply scarcity, noting that stakeholders have suggested that the current setting of 48-52 Hz places an excessive obligation for connecting generators through the application of NER S5.2.5.3.
- Whether the existing frequency containment and recovery bands for non-credible contingency events and protected events remain fit for purpose and opportunities to improve the clarity and consistency of settings in the FOS for credible events.
- The inclusion in the FOS of limits for the maximum size of credible contingency events for the Tasmanian region. This includes advice on:
  - Whether the existing limit of 144 megawatts (MW) for the largest allowable generation event in the Tasmanian region and system remains appropriate. This includes an assessment of the system security and operational implications of raising this limit to 155 MW, as proposed by Woolnorth Renewables.
  - Whether the generation limit in Tasmania should be extended to apply to network and load events. In its submission to the issues paper, TasNetworks expressed support for the application of a similar limit for the largest load event in Tasmania.
- Whether the FOS should include a limit on the maximum credible contingency event for the mainland system and whether such a limit should apply for generation, load and/or network events.

1.1.4 The limit for accumulated time error in the NEM

Advice on:

- The security and operational impacts and other related learnings since the Panel's 2017 determination to increase the limit on accumulated time error in the mainland NEM from 5 seconds to 15 seconds.
- AEMO's view on further potential reforms to the limit on accumulated time error, including consideration of potential options including:
  - Maintenance of the current limit on accumulated time error.
  - Removal of the limit on accumulated time error.
  - That the limit on accumulated time error apply over a period of time, rather than being an absolute limit. AEMO's advice is sought on how such a time-based limit on accumulated time error may be set. This may be informed by analysis of the rate of accumulation of time error over time in the NEM and what rate of accumulation is considered to be 'good operating practice'.

1.2 History of the FOS

In September 2001, a FOS for the mainland NEM was developed in consultation with stakeholders and determined by the National Electricity Code Administrator (NECA) Reliability Panel. The purpose of the FOS was to define allowable frequencies for the mainland NEM electricity power system under different conditions. Generator, network and consumer equipment is required to be capable of safely operating within the allowable frequency ranges as defined in the FOS.

AEMO is responsible for maintaining the frequency within the allowable ranges as defined in the FOS. The history of FOS reviews and the key outcome of each review is summarised in the table below.

Table 1 History of the FOS reviews and the key review outcomes

Year and scope	Key review outcomes
2019 Mainland and Tasmania	• Clarification of the limit on the size of the largest generation event in the Tasmanian power system • No change to FOS settings for contingency events or accumulated time error • Restructure
2017 Mainland and Tasmania	• Inclusion of a standard to apply following protected events • That AEMO use reasonable endeavours to meet the standard relating to non-credible multiple contingency events, that are not protected events. • An increase to the limit for accumulated time error in the mainland from 5 seconds to 15 seconds. • Generation event expanded to include sudden, unexpected change in generation output of 50 MW or more within 30 seconds.
2009 Mainland	• Inclusion of the elements of the FOS that apply for periods of supply scarcity – during restoration following large non-credible events that result in load shedding.
2008 Tasmania	• Revision of the FOS for Tasmania to support the connection of higher efficiency thermal generating units –Tamar valley power station.
2006 Tasmania	• Determination of the initial Tasmanian FOS based on previous standard set by the Tasmania reliability and network planning panel
2001 Mainland	• Comprehensive review and creation of the FOS for the mainland

The FOS is deeply embedded across the NEM with 21 years of application, implementation, and operational experience. The five reviews of the FOS since inception 21 years ago have each focused on improving or creating one or two specific components rather than many changes to the standard at once.

Frequency and voltage are the most critical NEM parameters to keep within limits to avoid risk of failure. As such, the FOS is critical to the ongoing secure operation of the NEM. Any changes must be well considered in their design and proven in their application to mitigate the risk of perverse or unintended consequences.

1.3 Context of the FOS review in the present power system

Australia's NEM is in the relatively early phases of an entire transformation of the physical power system that will change how and where energy is generated and consumed. The largest change to the power system since it was first built will see significant existing thermal generation assets replaced with renewables and energy storage, and reconfiguration of the grid to support two-way energy flow from mostly non-synchronous sources. However, the physics, science and electrical engineering principles underpinning the generation, transportation, storage and use of electricity will remain the same.

Consumers are more active in the power system than ever before, participating in generation and system services such as frequency control ancillary services (FCAS) through distributed solar and batteries in homes and businesses. Technologies continue to integrate transport, industry, offices, factories, communities, and homes into the supply side of the energy markets and power system. In addition, Australia has a fleet of ageing coal and gas thermal generation plants which are forecasting closures sooner than expected due in part to the push for net zero emissions by 2050 and a range of targets over the next 25 years.

The 'Step Change' scenario in AEMO's *Integrated System Plan* (ISP) 2022 projects renewables generating 83% of NEM energy by 2030-31. Governments and investors have focused even more on climate, environmental and social considerations, with New South Wales, Victoria and Queensland recently announcing details for many gigawatts (GW) of renewable energy projects.

This rapid, unprecedented pace of energy system transformation across Australia requires careful consideration and planning of technical standards that will meet requirements of the system as it progresses through transformational change. The technical standards that underpin secure operation of the power system must continue to underpin the ability of the NEM to meet its objective by providing reliable, secure and affordable electricity to consumers.

2 Frequency performance during normal operation

This section provides advice on the settings in the FOS for normal operation, including:

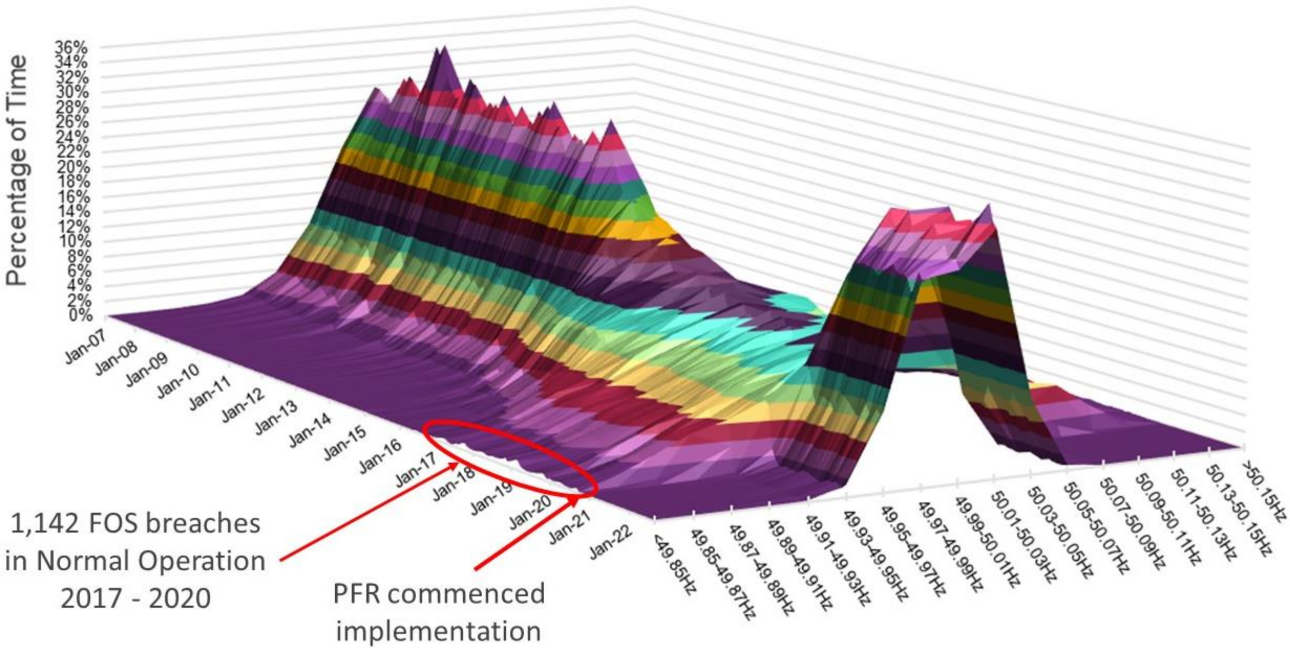
- The target distribution for frequency during normal operation.
- The system security and operational implications of setting the primary frequency control band (PFCB) at a range of settings between the current 'narrow' setting of 49.985-50.015 Hz and a wide setting of 49.5-50.5 Hz.

Relevant factors and operational experience that AEMO has considered in relation to maintaining frequency during normal operation are examined in sections 0 to 2.3. AEMO's advice on these matters is brought together in Section 2.4.

2.1 Historical frequency performance during normal operation

Figure 1 shows the deterioration of frequency in the NEM that commenced in 2014 and continued through to late 2020 when the mandatory primary frequency response (PFR) rule[1] commenced implementation.

Figure 1 Frequency distribution within the NOFB since 2007



Of particular note, evidenced by the definitive pointed peak at exactly 50 Hz between 2007 and 2015, most units on the power system had no deadband. The 'flat top' or twin peaks seen after 2020 are evidence of the +/- 15 millihertz (mHz) deadband.

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[1] National Electricity Amendment (Mandatory primary frequency response) Rule 2020 No. 5. Available on Australian Energy Market Commission (AEMC) website at https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response.

The mandatory PFR rule enabled AEMO to develop a set of PFR requirements (PFRR) for deadband limits, droop control and time constraints to be implemented by non-exempt semi-scheduled and scheduled generators. The progressive implementation of the PFRR has enabled AEMO to re-establish primary control of frequency in the NEM.

In 2019, AEMO commenced increasing the base volume of secondary control (regulation FCAS) to attempt better control of frequency within the normal operating frequency band (NOFB). While the increases slightly reduced the number of breaches of the FOS, latency issues inherent to secondary control systems, proved centralised secondary control was unsuitable as the sole mechanism for correcting ongoing rapid movements in frequency within the NOFB.

In the period leading up to PFR implementation, AEMO had no effective tools under the NER to successfully control frequency within the NOFB. Although some stakeholders suggested that the FOS required review before any improvements could be made, the real issue was an absence of frequency control due to the gradual erosion and removal of generator control settings from around 2014. Frequency control had to be re-instated without delay as the NEM was the least resilient it had ever been. Between 2014 and 2020 the number of events leading to load shedding was well above average, and there was an unprecedented number of breaches of the FOS in the mainland and Tasmania, particularly from 2017.

AEMO sought the advice of international power system control expert John Undrill, who stated in his report[2]:

> *"The present unsatisfactory behaviour of the NEM frequency is very likely not explained by deficiency in the design or tuning of the AGC system or by the absence of required primary control equipment at the power plants. Rather, it seems to be due to the ill-advised application of power plant primary controls that could readily execute the required control actions if properly applied and adjusted."*

AEMO and Dr. Peter Sokolowski proposed separate rule changes to improve the control of frequency in the NEM. The mandatory PFR rule was completed by the Australian Energy Market Commission (AEMC) in March 2020, and AEMO released the PFRR and commenced work with generators to implement changes to control settings from June 2020. The re-establishment of primary control is evidenced by the improvement in frequency seen in Figure 1 from late 2020.

Prior to the implementation of PFR, there was no control of frequency within the NOFB. Following the broad, though not yet completed, implementation of narrow band PFR, AEMO has seen a restoration of frequency control to the power system with a dramatic change in frequency performance enabling the following benefits:

- Improved resilience to non-credible events as evidenced by an AEMO loss of SCADA event, QNI separation, SA separation and many smaller events that have previously had a larger impact on the system.
- Contingency FCAS is no longer utilised in normal operation.
- Redundancy in the event of a central control failure
- Supports more accurate system modelling, allowing accurate design of specialist protection and control schemes.
- Allows for refinement and improvement of secondary frequency control through the AEMO automatic generation control (AGC).

[2] See https://www.aemc.gov.au/sites/default/files/2019-08/International%20Expert%20Advice%20-%20Notes%20on%20frequency%20control.pdf.

- Has enabled the aggregate frequency responsiveness[3] in MW/Hz across the NEM, that prevents rapid changes in frequency and therefore mitigates the primary control duty that each unit needs to provide.

The re-introduction of PFR control into the power system has enabled a resilient, predictable, and controllable system. This will enable a more secure transition to higher penetrations of variable renewable energy. To securely enable a power system in transition and the power system of the future, a mandatory approach to system control of frequency was required. Proportional response from the generation source whereby every unit does its share, including inverter based renewable generation will enable tight primary frequency control during the power system transition and well into the future.

2.1.1 Compliance with the FOS

Table 2 shows the number of FOS breaches in each calendar year from 2017 to 2021.

Table 2 Number of breaches of the FOS 2017-2021

Year	Mainland	Tasmania
2017	66	194
2018	49	322
2019	30	180
2020	26	170
2021	0	105
Total	**171**	**971**

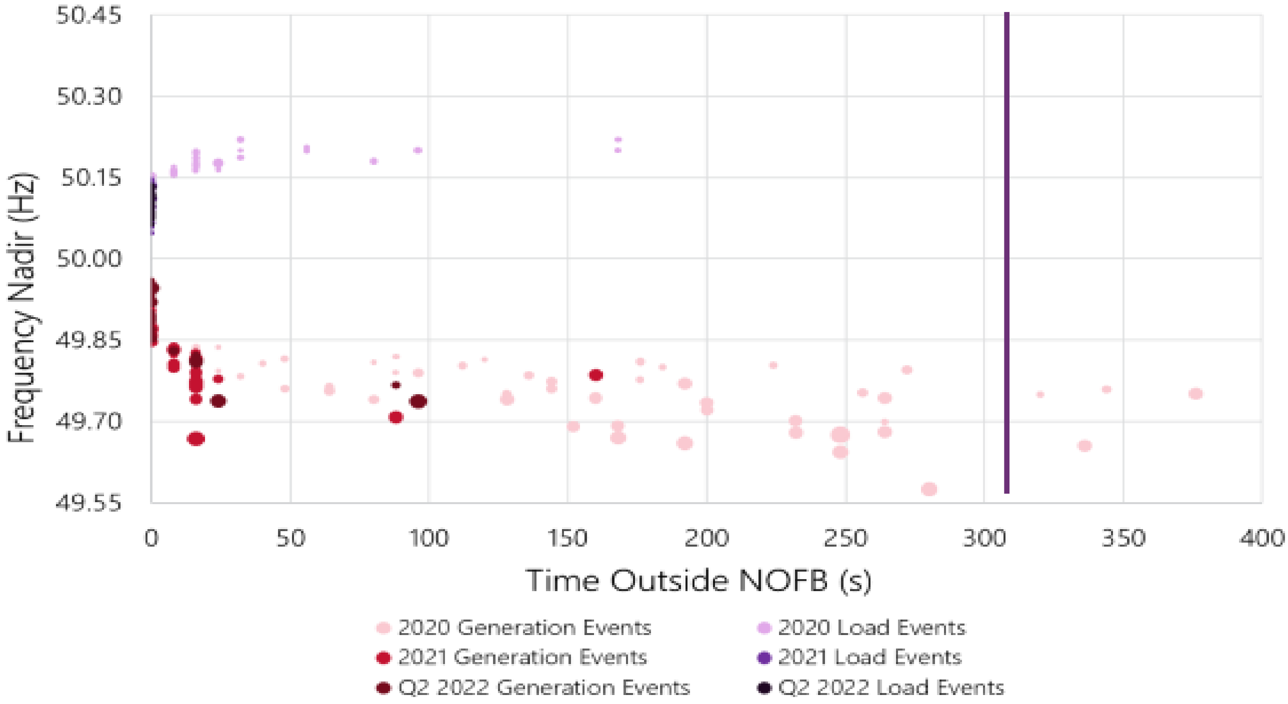
From 2017 through to 2021, the FOS was breached 171 times on the mainland and 971 times in Tasmania.

Since commencing the implementation of the PFR improvements to generator control system settings, no breaches of the FOS have occurred on the mainland and a significant reduction of FOS breaches has been observed in Tasmania. AEMO continues to work with generators and equipment manufacturers to assist and co-ordinate changes to improve control system settings across the NEM semi-scheduled and scheduled fleet of resources.

Figure 2 shows the improvement of frequency between 2020 and 2022. The light pink dots of 2020 (in the bottom right of the chart) show breaches of the FOS outside the 300 second (5-minute) mark. There is a marked transition for 2021 and 2022, which shows frequency progressively closer to 50 Hz and spending less time outside the NOFB as more units are enabled with suitable control settings.

[3] Aggregate frequency responsiveness is the combined MW/Hz response across all generators in the NEM.

Figure 2 Time spent outside of the FOS NOFB 2020-2022



Note: Size of contingency event is represented by bubble size.

2.2 AEMO implementation of the FOS for normal operation

AEMO operates the NEM to enable the power system to meet the FOS based on the following critical parameters:

- The frequency **target** is 50 Hz.
- The NOFB is the **allowable range of movement** away from the 50 Hz target during normal operation and is between 49.85 Hz and 50.15 Hz.
- The FOS provides the **allowable range of movement** for several scenarios and conditions on the power system outside of normal operation.

Maintaining frequency as close as possible to the frequency target of 50 Hz is required so that:

- The power system is always prepared for load or generator events and not biased in either direction that may cause undesirable frequency deterioration.
- The power system is designed based on a 50 Hz frequency with consideration to the allowable range of movement for margins of safety due to natural variation.
- Consumer equipment is not damaged. Consumer equipment is designed based on a constant reliable near 50 Hz frequency.

AEMO emphasises that the FOS frequency target is 50 Hz with allowable movement for expected deviations. For example, AEMO does not (and indeed cannot) aim to achieve 49.5 Hz for every generator trip, or 50.5 Hz for every potline trip. AEMO aims for a specific number (the 50 Hz target) and not a range of numbers in the design of control and protection systems, utilising an allowable movement range as a tolerance to manage rounding error, natural deviations and a variety of risks.

2.2.1 Tools available to AEMO to control frequency

The continuous balancing of supply and demand in the NEM, including the implementation of guardrails for when contingencies occur, comprises an integrated, large, distributed control system. Each component of the FOS results in a network system of equipment parameters and settings based on various engineering calculations, data feeds, real time automated analysis and feedback loops. These parameters are designed based on the FOS and implemented to maintain power system control to retain, recover, then restore frequency to the target of 50 Hz following disturbances.

Table 3 summarises each part of the frequency control chain in terms of the underlying function, the source of frequency variation it is intended to address, and how it is implemented in the NEM.

Table 3 Frequency control in the NEM

Stage	Role	Control action	NEM Mechanism	Typical response	Variability addressed
Inertia	Inherently acts to slow frequency change	No control action. Physical power system response.	Minimum inertia requirements.	Instantaneous response through conversion of kinetic energy to changes in frequency, acting all the time.	Reduces rate of change of frequency following a disturbance.
Primary control	Dynamic active power response to frequency change	Automatic proportional or triggered response. Strictly locally detected.	Currently MPFR for scheduled and semi-scheduled generators for frequency deviations commencing at 50 ± 0.015 Hz	Fast, *automatic* active power response through proportional frequency-droop response.	Small deviations caused by small imbalances in generation and load.
			Contingency FCAS reserves for frequency deviations outside the NOFB (50 ± 0.15 Hz) Enabled through dispatch instructions, for 1s (from October 2023), 6s, 5min & 60min services.	Fast, *triggered* response of reserves via either proportional frequency-droop or switched response controls.	Large sudden frequency deviations due to contingency events.
Secondary control	Supervises and acts to restore units to set point within the dispatch interval	Automatic; proportional and integral response to frequency, time error and variation from basepoint. Remotely co-ordinated.	Regulation FCAS reserves for frequency deviations within the NOFB. AGC signals sent through supervisory control and data acquisition (SCADA) to all enabled plant every four seconds, acting over tens of seconds to minutes.	Slower response with detection and feedback loop between unit and dispatch to adjust unit set point controllers.	Forecast error, frequency and time error due to system supply-demand variations within the dispatch interval.
Tertiary control	Supervises and restores reserves from one dispatch interval to the next	Allocated by system operator. Regional dispatch and inter-area flows	Central energy dispatch and FCAS reserve enablement through NEMDE.	Rebalancing at each dispatch interval.	Generation and load variability from one dispatch interval to the next.

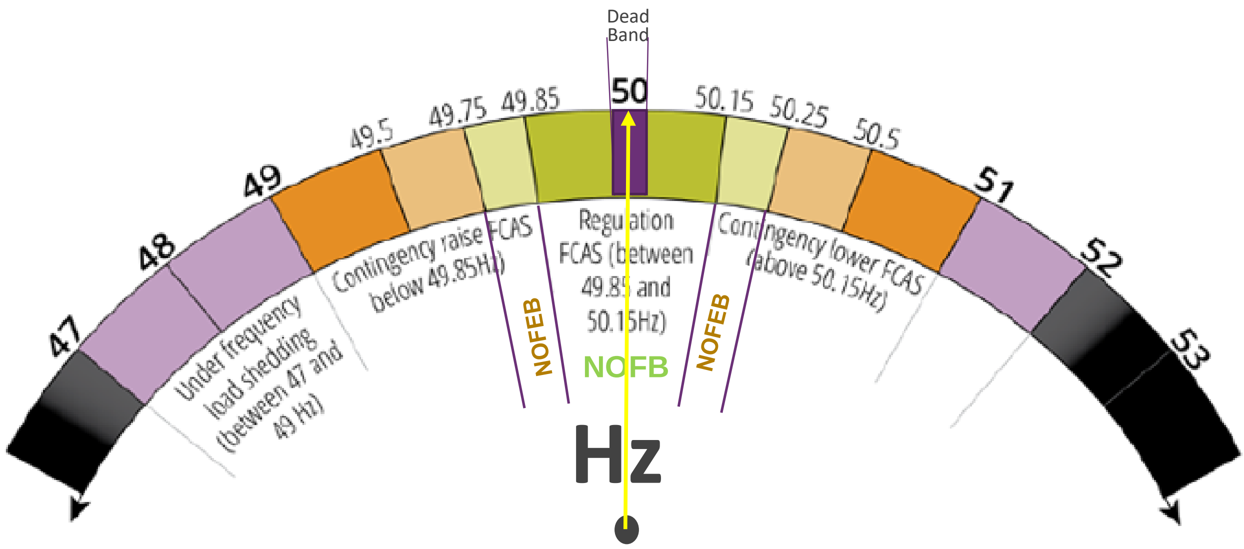
Stage	Role	Control action	NEM Mechanism	Typical response	Variability addressed
Emergency control	Arrest severe, rapid frequency changes, reducing risk of further cascading faults	Automatic, triggered shedding of load or generation. Local detection and response.	Emergency frequency control schemes to manage large, uncontrolled frequency changes resulting from non-credible loss of generation or load.	Controlled shedding of load, generation or storage response through frequency-sensitive relays to rebalance load and generation.	Sudden, rapid frequency changes due to major non-credible MW changes.

The NEM has re-established a foundation to control frequency performance under normal conditions. PFR has played an important role to re-establish primary and secondary control within the NOFB, enabling a resilient platform as the NEM transitions to more variable resources with very different operating characteristics.

As variable renewable energy (VRE) sources increase penetration across the power system, proper control of frequency within the NOFB must be strongly maintained. Between 2014 and late 2020, AEMO did not have an effective control mechanism to successfully control frequency within the NOFB.

Figure 3 below shows the various frequency bands outlined in the FOS, identifying the 50 Hz target, the deadband where there is no control, the NOFB, and the normal operating frequency excursion band (NOFEB). Primary control response within the NOFB commences at the edges of the PFCB at 49.985 Hz and 50.015 Hz.

Figure 3 Frequency control bands in the NEM – normal operation band



2.3 Primary Frequency Response Control Band

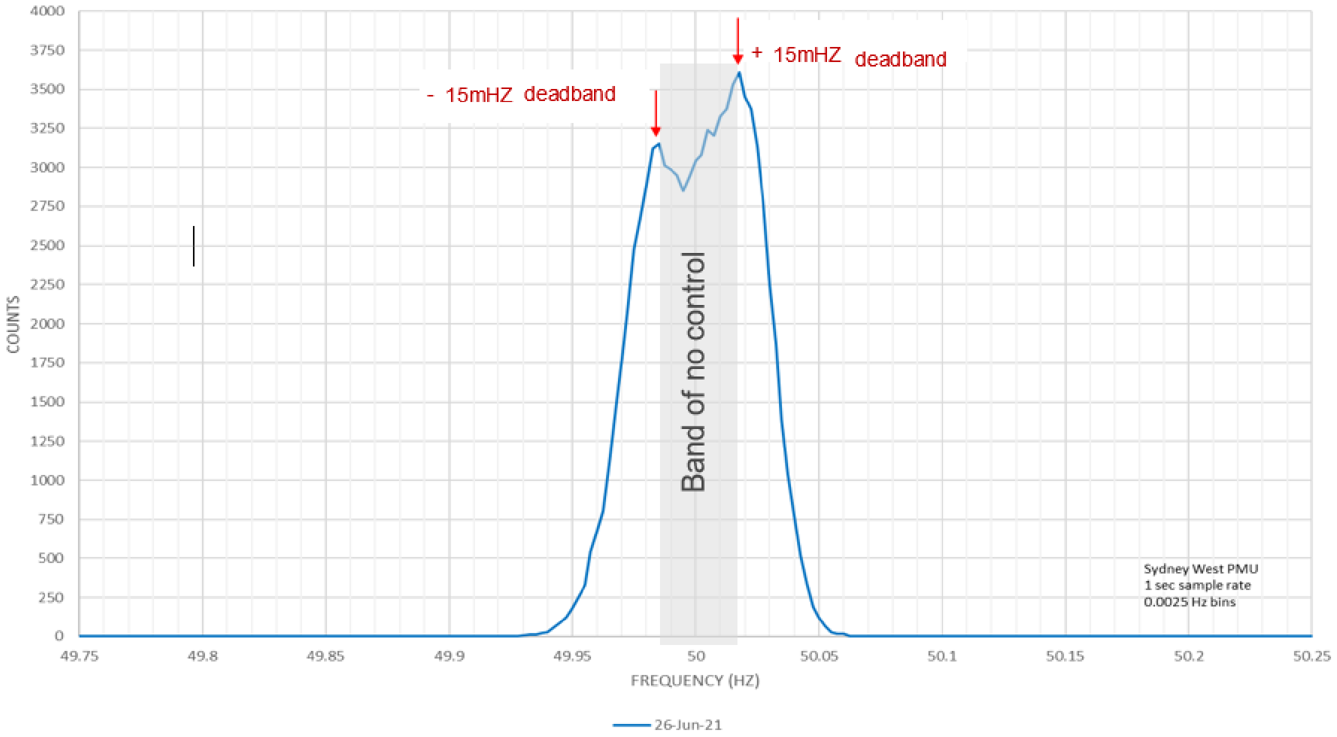
PFR is based on the local detection and response of plant control systems to changes in power system frequency. This provides a dynamic active power response, typically in proportion to the frequency deviation. Effective PFR establishes a strong control base, supporting the action of slower-designed controls and enabling optimised outcomes across the frequency control system. Primary and secondary controls do not act independently or in sequence; rather they are continuously active, complementing each other to provide effective control of frequency.

Within the NOFB, PFR commences at the edges of the PFCB deadband.

2.3.1 Deadband

The deadband specifies an operating zone around the nominal 50 Hz frequency where the generator will not adjust its power in response to frequency deviations. The mandatory PFR rule established a deadband of ± 0.015 Hz[4] for generators, introducing a new PFCB of 49.985 Hz to 50.015 Hz. Note that the rule allows for some variation in deadband for those plants not able to meet this specification for technical reasons only.

Figure 4 The effect of introducing deadbands into primary frequency controllers



As can be seen in Figure 4, frequency is mostly at the edges of the deadband. As such, a wider deadband will result in less control and less system resilience.

2.3.2 Role of inertial response

The inertial response of a power system is instantaneous and assists in limiting the RoCoF during large disturbances so that control systems have time to respond. Inertial response is an inherent physical characteristic of rotating synchronous machines provided through acceleration or deceleration in response to frequency changes. Inertia can in theory be substituted to some degree, but not entirely by very fast injections or absorptions of energy from inverter-based resources (IBR). A 1-second fast frequency response (FFR) mechanism (very fast FCAS) will be implemented in the NEM by October 2023. The level of inertia in the power system determines how fast the power system frequency will change in the first few seconds of a frequency disturbance.

Section 4 of this document reviews requirements for the implementation of a RoCoF standard in the FOS.

[4] In some jurisdictions this is referred to as a 30 mHz deadband.

2.3.3 Role of primary frequency control

PFR (within seconds and up to 30 seconds) is a response to locally measured frequency not subject to centralised control, communications delays and time synchronisation issues. Being primary at the source, it is a fast-acting response to frequency change. A response typically starts immediately and is an automatic response to adjust generation output to arrest and stabilise (but not necessarily restore) frequency, typically in proportion to the frequency deviation. This takes place through the local detection of frequency deviations from the nominal 50 Hz (Δf) initiating an automatic internal control signal to the generating unit (ΔPp or up) for an active power response.

Historically in the NEM, only synchronous generating systems provided PFR. It is now also being provided by wind, batteries and photovoltaic (PV) generation. As these technologies will form an increasingly large proportion of the supply mix in the future, it is important that any PFR arrangements consider the capabilities and performance of these newer technologies adequately. For this reason, AEMO proposed a mandatory PFR rule so that the expectation was set for all VRE and IBR technologies to be frequency responsive, enabling further penetration of new technologies as synchronous thermal units retire.

Over the last two years, primary control of frequency has been re-established in the NEM based on a proportional droop response when frequency leaves a ±0.015 Hz deadband around 50 Hz.

In addition, contingency FCAS via proportional controls, or increasingly via switched controllers, are also a form of primary control, though they are only required when the frequency deviation is beyond the NOFB. Contingency FCAS is not designed to control, or capable of controlling, frequency to a 50 Hz setpoint.

2.3.4 Role of secondary control (regulation FCAS)

The secondary control loop complements the primary control, acting over slower timeframes (tens of seconds to minutes) to correct more sustained sources of variability or error accumulating over time, which primary controllers have initially responded to. This is achieved through addition of a centralised control signal (ΔPs or us) fed back to plant-level primary controllers as a change in dispatch setpoints. Secondary control is specifically designed to act over slower timeframes than ongoing frequency changes, to complement the primary control – not act as a replacement for it.

This centralised control uses an error signal known as the area control error (ACE) representing the imbalance between generation and load, which is proportional to frequency deviations from the nominal 50 Hz (Δf). As primary control responds to frequency deviations on a proportional basis, it may not be able to achieve the reference values alone. Some offset may still exist due to energy dispatch forecast error, frequency and time error. This means secondary control must also include a level of integral control, reflecting how long and how far frequency has been from its nominal value over a period of time. Secondary control can also take into account how units have moved from their nominal basepoints as a result of primary control action.

In the NEM, secondary control is implemented through central control of regulation FCAS reserves via AGC commands sent through the NEM SCADA system. This acts to fine-tune controller set points to slowly correct deviations in frequency and help return units to their basepoints. In March 2019, AEMO commenced increasing base volumes of regulation FCAS procured for the mainland. Regulation FCAS was, at the time, the only tool available to AEMO to control frequency under normal operating conditions and increasing regulation FCAS was an attempt to improve frequency control to the point where AEMO could meet the minimal requirements of the FOS under normal operating conditions.

The design of AGC restricts its ability to actively manage frequency successfully on its own. AGC is used to manage forecast errors, control time error, and provide a slow correction of power system frequency. It is not suitable as the sole mechanism for correcting ongoing rapid movements in frequency within the NOFB.

Prior to March 2019, the base volumes of regulation FCAS procured were 130 MW regulation raise and 120 regulation lower.

Table 4 shows the increases to the base regulation FCAS volumes made by AEMO from March 2019.

Table 4 Increases in base regulation FCAS volume from March 2019

Date	Increase	Total base volume
22 March 2019	50 MW	Regulation raise 180 MW, regulation lower 170 MW
23 April 2019	20 MW	Regulation raise 200 MW, regulation lower 190 MW

The increase in secondary control reserves did not narrow the distribution of frequency or improve the stability of control of frequency within the NOFB. At best, power system frequency was not exiting the NOFB as frequently or remaining outside the NOFB as long. An aggregate increase of 70 MW of base regulation FCAS volume did not address the decline in the stability of frequency control close to 50 Hz.

Presently, the regulation FCAS requirement can be up to 250 MW. AEMO will review this volume as more variability of generation is observed with increasing renewable energy capacities. PFR keeps frequency close to 50 Hz by resisting movements outside of a deadband. Secondary control points frequency back to 50 Hz by accounting for and correcting errors in forecast and dispatch. Both primary and secondary control are required to work together for effective power system frequency control.

2.3.5 Role of tertiary control (central dispatch)

Tertiary control acts to restore the primary and secondary control reserves and assist the return of frequency to nominal values if secondary reserves are not sufficient. In the NEM, tertiary control is effectively achieved through the central energy re-dispatch process, rebalancing the system and allocating and restoring FCAS reserves at each five-minute dispatch interval.

2.3.6 Role of emergency controls

Emergency controls serve as the 'last line of defence' in the event of high impact, low probability contingency events that might otherwise result in widespread and prolonged outages if not stopped. In the NEM emergency frequency control schemes (such as under frequency load shedding [UFLS] and over frequency generation shedding [OFGS]) are designed to rapidly rebalance the system upon detection of a severe, rapid frequency deviation. Emergency level active power controls implemented by facility owners (such as specialised wideband frequency response controls) could also fall into this category.

2.4 AEMO advice for frequency performance during normal operation

2.4.1 Normal operation NOFB and NOFEB on the mainland and Tasmania

AEMO advises there should be <u>no change</u> to the parameters in the FOS for normal operation on the mainland.

This is based on the following key considerations:

- The NEM power system is in the early stages of a complete transformation of generation, transmission, distribution and consumer load technologies and operation. However, the physics, science and electrical engineering principles remain the same.
- Frequency is a critical technical property for the stability of the power system. Frequency control principles have not changed.
- Mandatory narrow band PFR enabled successful control of the NEM to be reinstated after a period of unacceptable poor control of frequency.
- The NEM power system is now in a strong position to enable a transition to renewable energy sources with a firm basis of known frequency control practices.
- Given the extreme volume of work to be completed by the energy industry to facilitate the transformation, amending the normal operation parameters of the FOS are not a priority at this point in time and changes could present unknown risks.
- AEMO notes that investigations into the NOFEB requirements and capabilities in Tasmania are ongoing and AEMO may propose a modification via a submission at a later date.

2.4.2 PFCB on mainland and Tasmania

AEMO advises there should be no change to the PFCB of +/- 0.015Hz for the mainland and Tasmania.

This is based on:

- The introduction of a 30 mHz deadband primary response has re-established control of frequency in the NEM and enabled many benefits including resilience to significant contingencies and predictable frequency responses.
- The frequency control improvements delivered by mandatory 'narrow band' PFR are undeniable. AEMO is not aware of any evidence of tangible benefits from reducing frequency control on the power system, particularly when the largest transformation ever experienced by the energy industry is just commencing.
- A PFR incentives rule[5] has recently been finalised to incentivise generators and loads to provide capacity for primary response. As an industry, AEMO suggests this should be implemented and given time to observe its operation for a period before considering any modification of the PFCB.
- The considerable effort and costs to AEMO and the industry to change the PFR settings should not be underestimated or dismissed.

2.4.3 Frequency target of 50 Hz

AEMO recommends, to remove all doubt, the FOS clearly states the target frequency for the NEM is 50 Hz.

This is based on:

- All calculations for frequency management, protection schemes, deviations etc. require a specific number not a range. All existing calculations use 50 Hz.

[5] National Electricity Amendment (Primary frequency response incentive arrangements) Rule 2022 No. 8. Available on the AEMC website at https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements.

- It has always been accepted and understood that the NEM frequency target is 50 Hz, though this is not explicitly stated in regulatory instruments.

3 Limits on rate of change of frequency for the power system

This section provides AEMO's advice on the system security and operational benefits of setting limit(s) on RoCoF following contingency events in the NEM, considering:

- The technical capability of current power system plant to withstand different levels of RoCoF following contingency events.
- The expected capabilities and limitations of protection schemes, including automatic UFLS, with respect to RoCoF.
- The role that a RoCoF limit would play in the operation of the power system, including with respect to the provision of very fast FCAS and physical and synthetic inertia.
- How RoCoF limits are specified and the reasoning for these formatting or measurement approaches. For example, the value for RoCoF in Hz/s and the time-period over which this is measured and whether RoCoF limits should be varied for different NEM regions and different operating conditions.

Relevant factors and operational experience that AEMO has considered in relation to RoCoF limits are examined in sections 3.1 to 3.5. AEMO's advice on these matters is brought together in Section 3.5.

3.1 RoCoF withstand capabilities

RoCoF withstand reflects the technical capability of power system plant to withstand different levels of RoCoF following contingency events.

This has been a key area of study and interest globally, though remains uncertain. In Ireland, market operator Eirgrid performed on-line tests to research this topic. AEMO has been investigating withstand capabilities of generators in the NEM for many years.

3.1.1 Review of RoCoF vulnerabilities

AEMO conducted a review in 2017 exploring the RoCoF ride-through capabilities and vulnerabilities of generating units and other power system elements. This included:

- Commissioning a review on international findings of RoCoF vulnerabilities[6].
- Engaging GE to provide a review of all power system elements in the South Australian grid, and identify any potential areas of risk[7].
- An AEMO representative visiting Ireland and engaging in a series of detailed interviews with EirGrid (the power system operator in Ireland), who was in the process of an extensive process to test RoCoF ride-through capabilities of all individual generating units in their power system.

[6] DGA Consulting (October 2016) International Review of Frequency Control Adaptation, Section 3 – Experiences with high RoCoF, at chttps://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2016/FPSS-International-Review-of-Frequency-Control.pdf.

[7] GE Energy Consulting 2017, *Advisory on Equipment Limits associated with High RoCoF*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/20170904-GE-RoCoF-Advisory.

- Engaging consultants to conduct modelling of the behaviour of specific synchronous generating units in South Australia to understand risks of pole slipping (losing synchronism) under high RoCoF. The approach applied was considered unsuitable for assessment of individual unit limits due to limitations in the accuracy of the generator models applied (models may not be a complete reflection of those specific generators). However, it may provide guidance on general trends in the elements that affect RoCoF vulnerability.

3.1.2 Findings from review of RoCoF vulnerabilities

Despite considerable efforts, there remains significant uncertainty over the RoCoF ride-through capabilities of power system equipment, and significant gaps in AEMO's knowledge and understanding of behaviour of the power system under high RoCoF conditions remain. However, findings from these studies and reviews include those summarised below.

Inverter-based generation

- Can generally be expected to ride through high RoCoF (up to 3-4 Hz/s), as long as there is no specific RoCoF-based protection applied, or mis-operation of protection schemes.

Synchronous generating units

- Can generally be anticipated to successfully ride-through disturbances up to 1 Hz/s (with some exceptions), but many demonstrate a range of issues for disturbances in the vicinity of 2 Hz/s or higher.
- Significant risks were identified of:
  - Gas-fired generation tripping due to lean blow out (LBO) on high positive RoCoF (rapidly rising frequency). This can occur after loss of an interconnector when exporting from a region, or loss of load. High positive RoCoF can also occur following a severe under-frequency event during the recovery phase (following the nadir), especially if there is excessive load shedding causing frequency rebound and overshoot.
  - Gas-fired generation tripping due to compressor surge on high negative RoCoF (rapidly dropping frequency). This can occur following loss of an interconnector when importing into a region, or loss of generation within an islanded area.
  - For all synchronous units, potential for misbehaviour of power system stabilizers, especially those which calculate accelerating power.
- Vulnerability to RoCoF depends on many factors, including:
  - The nature of the unit. In general, the highest RoCoF vulnerabilities are identified for units with higher inertia, particularly for gas-fired units (large industrial frame gas turbines).
  - Where the unit is connected. Units in electrically remote locations may be more vulnerable to high RoCoF.
  - How the unit is operating. The modelling suggested that RoCoF ride-through capabilities may be reduced when units operate at higher power setpoints, and when operating with an under-excited (leading) power factor.
  - Ambient conditions. RoCoF vulnerability is increased in gas turbines for extremes of ambient temperature.
  - The nature of the disturbance. RoCoF ride-through capability is generally diminished where there are co-incident voltage events.

- The GE report noted that RoCoF levels exceeding ±2 Hz/s are rarely seen in interconnected systems of any kind and GT behaviour is not well understood beyond this range.

Distributed generation

- National Grid (UK) and Eirgrid (Ireland) have experienced and subsequently identified significant challenges associated with loss of mains protection on a large number of distribution-connected generating units which can trip a large proportion of generation under high RoCoF conditions (for example, explicit RoCoF protection or vector-shift protection, which can be triggered in high RoCoF events).
- Loss of mains protection does not appear to be a significant concern in the NEM. A small number of distributed PV inverters have been identified in bench testing studies to disconnect in response to high RoCoF[8], but these specific products do not form a significant proportion of installed capacity in the NEM at present. Of the 29 inverters tested, 25 successfully rode through up to ±4 Hz/s.
- There are not many distributed PV (DPV) inverters on the market with RoCoF vulnerability. Small DPV (<30 kilowatts [kW]) is the largest proportion of the NEM's distributed connected generation by far, so risks are mostly small. Explicit RoCoF ride-through is now required and tested for in Australian Standard AS4777.2:2020.
- For newer inverters, Australian Standard AS/NZS4777.2:2020 (mandatory from December 2021) now requires that distributed inverters maintain continuous operation for frequency excursions with a RoCoF up to ±4 Hz/s for a duration of 0.25 seconds, with a corresponding test procedure required (Test J). However, initial analysis suggested that compliance with this new standard was poor, with only around 35% of new installations between January and March 2022 appearing to have been compliant with the new standard[9]. AEMO has been working with industry bodies to try to improve compliance.
- There is a possibility that any older, larger distribution-connected wind/solar farms can have additional RoCoF or vector-shift protection that may trip when exposed to high RoCoF. AEMO has observed that larger distribution-connected systems are more prone to tripping. AEMO is familiar with one example in Energy Queensland's network with this type of protection. This risk is considered relatively small, given the very small quantity of this type of generation in the NEM at present.
- AEMO has requested all the distribution NSPs (DNSPs) to ensure and confirm that connection requirements do not allow vector-shift or RoCoF protection. It is understood these are generally not used any more, and most DNSPs have updated their connection requirements to not allow this type of protection.

Under-frequency load shedding

- There are limits to the RoCoF levels under which UFLS can function properly, outlined further in Section 3.2.

Other power system elements

- Protective schemes can mis-operate under high RoCoF because of poor settings; that is, the relay behaves as instructed, but has settings incompatible with high RoCoF. This is associated with all generators, as well as

[8] AEMO (May 2021) Behaviour of distributed resources during power system disturbances, Section 3.2.2, at https://aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

[9] AEMO (July 2022), Power System Frequency Risk Review, Section 3.3.1, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review.pdf?la=en.

transmission and distribution network elements. GE recommended that any remaining electro-magnetic relays in critical applications should be tested for RoCoF performance.

3.1.3 Historical events

Historical events can give an indication of the RoCoF ride-through capabilities of generating units in the power system, although the available data is very limited. This is because extreme RoCoF events are relatively rare, units must be operating at the time of the disturbance to give an indication of their capabilities, and as noted above the RoCoF ride-through capability of a unit can depend on factors that vary in different periods (such as how the unit is operating, ambient conditions, and the nature of the disturbance).

As an example, Table 5 lists all significant high RoCoF events recorded in South Australia since 2004. Only two exceeded -1.5 Hz/s (shown in bold). Observations for these two fastest RoCoF events are as follows:

- Ladbroke Power Station tripped in both the 2004 and 2005 events, attributed to the activation of distance protection. The RoCoF was -2.1 Hz/s in the 2004 event and -1.6 Hz/s in the 2005 event. The unit also showed possible signs of pole slipping in the 2004 event. Ladbroke has since undergone an upgrade and changes to control and protection settings which may reduce RoCoF vulnerability. However, this demonstrates that RoCoF vulnerabilities can exist in some units in these ranges.
- Pelican Point gas turbine (and subsequently steam turbine) tripped in the -1.6 Hz/s RoCoF event in 2005, and was not generating during the -2.1 Hz/s event in 2004.
- Torrens B and Osborne Power Stations were online in both high RoCoF events (2004 and 2005) and rode through successfully.

In 2016, there was also a RoCoF event of -1.2 Hz/s following a credible separation. All generators online for this event rode through successfully, including Pelican Point.

Table 5 Historical high RoCoF events

Date	Event	Max RoCoF (500ms avg)	Min SA Freq	Synchronous generator ride through	
				Successful	Unsuccessful
2004-03-08	**Non-credible separation**	**-2.1 Hz/s**	**47.6 Hz**	**Torrens B1, B3, B4** **Osborne GT + ST**	**Ladbroke**
2005-03-14	**Non-credible separation**	**-1.6 Hz/s**	**47.6 Hz**	**Torrens B2, B3, B4** **Osborne GT + ST**	**Pelican Point GT + ST** **Ladbroke**
2012-06-19	Earthquake	-0.42 Hz/s, +0.13 Hz/s	49.2 Hz	Torrens B3, B4 Pelican Point GT + ST	Torrens A4
2016-12-01	Credible separation	-1.2 Hz/s	48.2 Hz	Torrens B2, B3, B4 Pelican Point GT + ST Quarantine	-
2018-08-25	Non-credible separation	+0.65 Hz/s	49.15 Hz	Torrens A3, B1, B2, B3, B4 Osborne GT + ST Pelican Point GT + ST	-
2019-11-16	Non-credible separation	+1.2 Hz/s	49.8 Hz	Torrens B3, B4 Osborne GT + ST Pelican Point GT + ST	-
2020-01-31	Non-credible separation	+0.8 Hz/s	50 Hz	Torrens A1, A2, A4, B1, B2, B3 Osborne GT + ST Pelican Point GT + ST	-

This evidence is incomplete, although generally consistent with findings from AEMO's review indicating that RoCoF ride-through capabilities can vary considerably between units, may be in the range of 1-2 Hz/s for some synchronous units, and may also vary depending on the operating conditions for the unit at the time.

3.1.4 Generator survey

In August 2022, AEMO surveyed selected influential generating units in South Australia, requesting advice on any explicit RoCoF protection or known RoCoF ride-through capabilities/limitations. The main responses by generation category were:

- Synchronous generators.
  - There were no synchronous units identified with explicit protection elements or control schemes that will disconnect the unit due to RoCoF.
  - It is unclear how units will respond to high RoCoF beyond any stated capability in their Generator Performance Standard (GPS). Testing by the original equipment manufacturer (OEM) would be required to investigate any limits under a variety of operating conditions.
  - Generators noted that the complex interactions between turbine and generator make it difficult to estimate the performance of units under high RoCoF and that other conditions such as excitation, loading and ambient conditions can impact the performance or mechanism by which a unit may disconnect.
  - Where minimum RoCoF ranges are specified for continuous operation in a unit's GPS, usually the requirement was placed on the OEM when units were procured, and the generators or operators do not have any additional information on the unit's capability.
  - It is anticipated by respondents that investigation and modelling of a unit's capability by the OEM will involve significant time and costs.
- Wind farms.
  - Some older units were identified to have RoCoF protection elements as low as 1 Hz/s for 1 second in their GPS. AEMO has requested further information to clarify the exact settings on these protection elements.
- Grid-scale batteries.
  - All units surveyed meet the current automatic generator performance standard requirements for continuous uninterrupted operation for RoCoF as per NER section 5.2.5.3, Generating system response to frequency disturbances.
  - No explicit protection or control mechanisms were identified by surveyed units that would disconnect due to RoCoF.
  - Maximum RoCoF withstand limits are unknown as the OEMs have not performed this testing.
- Solar farms.
  - All units surveyed meet the current automatic generator performance standard requirements for continuous uninterrupted operation for RoCoF.
  - No additional information was received from solar farms on RoCoF ride-through capability.

3.2 Automatic under-frequency load shedding

UFLS is a last resort emergency mechanism, intended to manage severe non-credible contingency events that exceed the containment ability of FCAS. UFLS involves the automatic disconnection of load in less than a second to rapidly rebalance the power system.

There are limits to the RoCoF at which a UFLS scheme can function properly. At extreme RoCoF levels, frequency falls so rapidly that it can reach below minimum thresholds before the UFLS relays can trigger load disconnection to arrest the frequency decline. For example, in the 2016 South Australia Black System Event, RoCoF was so fast (in excess of -6 Hz/s[10]) that system frequency collapsed while the region's UFLS relays were still in their pickup time.

In some cases, there may be potential to somewhat shorten UFLS relay time delays/pickup times to improve performance under extreme RoCoF conditions. However, there are limits to how fast relays can operate reliably, explained further below.

3.2.1 UFLS relay operation times

The total time for UFLS relay operation can be broken down into the components summarised in Table 6. Indicative time delays for each component for relays in South Australia have been included as an example, based on advice provided to AEMO by SA Power Networks. The third column indicates the present settings, and the fourth column indicates the fastest possible settings anticipated if relays are replaced with the latest generation of modern electronic relays.

Table 6 Total relay operation time (example for South Australia)

UFLS relay operation component		Indicative time range for component to operate	Fastest possible times[A]
Relay response time	Includes both: • Time taken for relay to process/recognise initiating condition (e.g. frequency <49 Hz). • Time for relay contact to close.	80-120 ms depending on relay	50-120 ms
Deliberate delay / pickup time	Amount of time that initiating condition must be present for before relay decides to operate.	150-300 ms	150 ms
Auxiliary relay operating time (if present)	Time taken for auxiliary relay to operate.	10-60 ms	0 ms (no aux relay present)
Customer interface delay	Processing and sending trip signal due to safety or site-specific requirements. Applies to specific sites only.	0-450 ms	0 ms
Circuit breaker opening time	Time to open the circuit.	20-100 ms depending on breaker	Typically 50 ms
Total operation time		300-700 ms	250-320 ms

A. Based on the latest generation of relays (requires relay replacements).

Relays have a growing risk of mis-operation if pickup times are too short, due to interaction in internal relay elements or filtering methods on input measurements. For example, in AEMO's discussions with other power

[10] AEMO 2017, *Black system South Australia 28 September 2016*, Figure 6, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2017/integrated-final-report-sa-black-system-28-september-2016.pdf?la=en&hash=7C24C97478319A0F21F7B17F470DCA65.

system operators managing smaller grids that experience high RoCoF, UFLS relays set up to trigger on a RoCoF exceeding -2 Hz/s with a 3 cycle (50-60 ms) delay were found to often trip erroneously during faults, particularly multiple phase faults. This leads to undesired customer interruptions.

To allow accurate measurement of power system frequency during real power system disturbances, which often involve “messy” disruption to the voltage waveform, relays typically require at least 5-8 cycles (100-160 ms) as a measurement window. This avoids spurious triggering of relays on short frequency transients and other power system phenomena where the voltage waveform may be disturbed in messy ways and the definition of power system frequency may depend on the nuances of exactly how it is measured over the small number of cycles within the measurement window. NSPs and other power system operators have advised AEMO that the fastest relay pickup time that is feasible and adequately avoids spurious tripping is approximately 100-200 ms, which, when allowing for further delays for communications and to operate breakers, leads to a total operation time of 300-400 ms for typical relays. Due to limitations at some customer locations, some relays have longer minimum operation times in the range of 600-700 ms.

There may be further limitations in the performance of UFLS based on the types of UFLS relays implemented in the network. If the RoCoF is too fast, is it possible that a relay could lose its tracking ability as the frequency decays rapidly. Various relay types may perform differently under these conditions, with most networks in the NEM having a range of types installed at present (including advanced digital relays, basic digital relays, solid state relays and older electromechanical relays). Extensive laboratory testing would be required to determine the likely performance of each relay type, in each region’s network. The behaviour of UFLS relays therefore has some uncertainty under these conditions.

The complexities and difficulties involved in measuring frequency accurately in very short timeframes are further elaborated in GE’s advice to AEMO on Fast Frequency Response[11] (which, like fast UFLS response, similarly requires robust fast measurement of frequency).

3.2.2 RoCoF limits of UFLS – case study

This section provides a case study example exploring the limits of operation of UFLS under extreme RoCoF conditions. A summary from the findings of this study is presented in Section 3.2.7.

Case study assumptions

Contingency event

A model of South Australia is used as an example, exploring outcomes in the South Australian island following a non-credible separation event (double-circuit trip of the Heywood Interconnector) co-incident with the trip of a large inverter-based generating unit of varying sizes, producing various levels of average RoCoF over the 300 ms immediately post separation.

Model limitations

The model applied is a simple multi-mass model in Simulink/Matlab, which does not account for voltage, reactive power or system strength effects. These effects are common in larger disturbances and will likely cause additional complications and mechanisms of failure during extreme RoCoF events, which are not accounted for in this

[11] GE Energy Consulting report to AEMO (9 March 2017) *Technology Capabilities for Fast Frequency Response*, Section 2.2.2 – Response Trigger Options, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/20170310-ge-ffr-advisory-report.pdf?la=en.

analysis. Any cases that reach frequency nadirs below 47 Hz are not expected to recover. Below this threshold, extensive generator disconnection is anticipated (not explicitly included in this model).

UFLS relay settings and block sizes

The present South Australian UFLS relay operation times, UFLS block sizes and UFLS frequency settings have been applied. As noted in Table 6, there is some potential to shorten relay operation times with replacement of relays to modern electronic relays. The possible benefits of this are explored further in a sensitivity below.

Acceptance criteria

In cases where RoCoF is too fast for UFLS to function successfully to arrest the frequency decline, the frequency nadir typically falls below necessary thresholds before the UFLS blocks have time to trip, and excessive load tripping (exceeding the contingency size) can occur, leading to frequency overshoot. To identify cases where this is occurring, the following acceptance criteria have been applied to determine whether UFLS is operating successfully to meet desired frequency outcomes:

- Frequency nadir is contained above 47.6 Hz (this allows an uncertainty margin above the 47 Hz threshold defined in the Frequency Operating Standard and avoids tripping of the most sensitive “last resort” loads included in the final UFLS bands at 47.5 Hz and 47.6 Hz).
- No frequency overshoot is observed (frequency zenith is less than 50 Hz).
- The amount of net UFLS load tripped does not significantly exceed the initial contingency size.

Case study assumptions

The case study period selected is a typical half-hourly overnight period with 0 MW DPV generation, typical UFLS load, typical inertia levels and moderate Heywood Interconnector (HIC) import levels, as summarised in Table 7. This case study period is based on a projected period modelled in 2023 in the AEMO 2022 ISP forecasts for the Step Change scenario. An overnight period has been selected to avoid the complicating factor of distributed PV generation impacting UFLS functionality. The IBR trip size was increased to achieve contingencies of varying instantaneous RoCoF levels.

Table 7 Pre-disturbance case study parameters

Parameter	Value
Distributed PV generating	0 MW
Net UFLS available	1,333 MW (1,312 MW on short delay bands, excluding 30s delay band)
Operational demand	1,552 MW
HIC imports into SA	165 MW
System inertia	5,861 megawatt seconds (MWs)
Non-credible contingency	• Double-circuit loss of the Heywood Interconnector (HIC), separating South Australia from the rest of the NEM, co-incident with trip of an IBR station. IBR trip does not result in any loss of power system inertia. • The IBR trip size was increased to achieve contingencies of varying instantaneous RoCoF levels. The modelled contingencies range from RoCoF of -1 Hz/s to -5 Hz/s, measured as an average over the 300 ms following the separation. • HIC separates and IBR station both trip simultaneously at time (t) = 0s in the model.

Several new loads added to the South Australia UFLS during 2019 to 2021 have been included in this analysis, such that almost all load in South Australia is now included in the UFLS scheme.

FFR delivered as a droop response by battery energy storage systems in South Australia with total combined headroom of 150 MW has also been included in the model, based on the median FFR raise response from Hornsdale battery.

Case study results

Figure 5 below shows outcomes for contingencies with varying RoCoF levels (with average RoCoF measured over the first 300 ms following the contingency event). The top panel shows the power system frequency in South Australia, and the bottom panel shows the net UFLS load tripped over time. The 4 Hz/s case shows extreme frequency overshoot, and in both the 4 Hz/s and 5 Hz/s cases all the net UFLS load in short delay frequency bands is tripped[12], exceeding the initial contingency size.

Figure 5 Outcomes for varying RoCoF levels

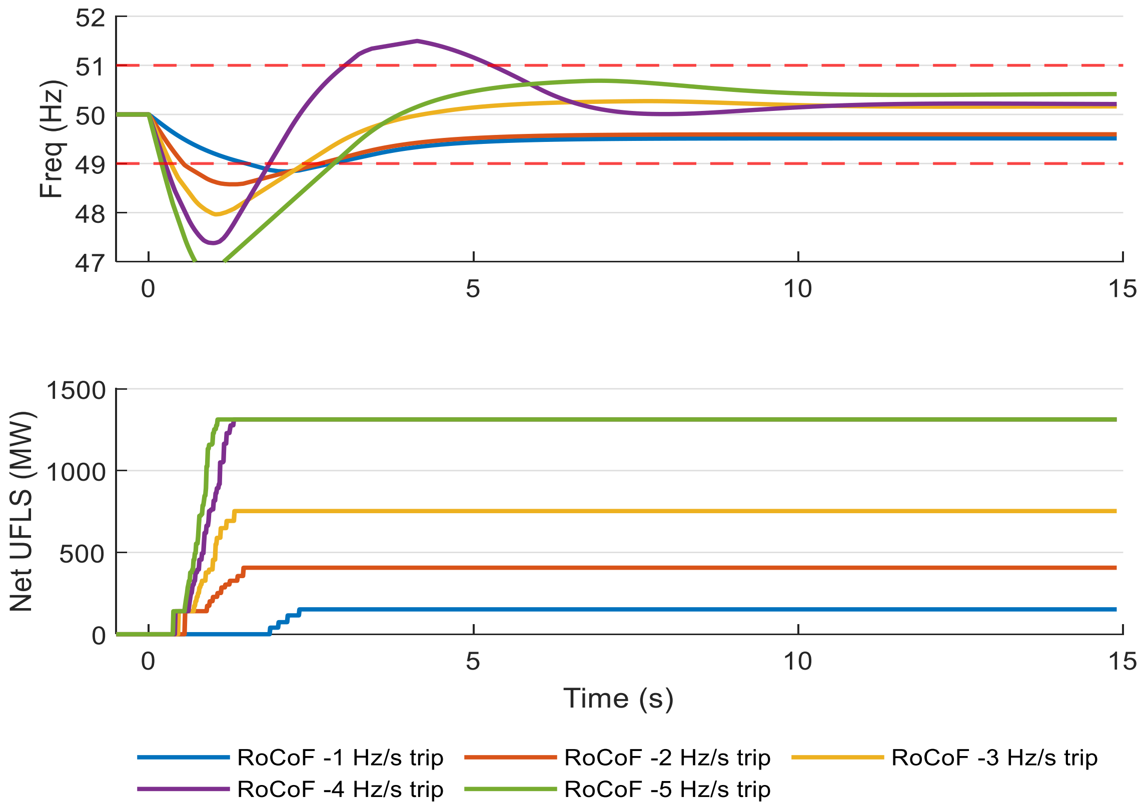


Table 8 summarises the outcomes for each of the modelled scenarios. Larger non-credible events leading to post contingent RoCoF at 4 Hz/s and 5 Hz/s both fail the acceptance criteria (frequency nadir is below 47.6 Hz, frequency overshoot is present, and the total amount of net UFLS load tripped exceeds the contingency size). For both cases, total cascading failure is considered likely. The case with RoCoF at 3 Hz/s also demonstrates some frequency overshoot and excessive load tripping, although the frequency is successfully arrested just below 48 Hz.

[12] There is a long time delay band (30s delay) which aims to assist frequency recovery. This is not tripped in the initial frequency arrest in these simulations.

Table 8 Summary of outcomes for varying RoCoF levels

Maximum RoCoF (moving average measured over a 300 ms window)	**-1 Hz/s**	**-2 Hz/s**	**-3 Hz/s**	**-4 Hz/s**	**-5 Hz/s**
Contingency size (HIC imports + IBR station trip)	235 MW	475 MW	705 MW	940 MW	1,185 MW
Frequency nadir	48.8 Hz	48.6 Hz	47.96 Hz	47.4 Hz	46.8 Hz*
Frequency zenith post contingency	49.8 Hz	49.6 Hz	50.3 Hz	51.5 Hz	50.7 Hz
Frequency of lowest UFLS block triggered	48.85 HZ	48.6 Hz	48 Hz	47.5 Hz	47.5 Hz
Net UFLS load tripped	152 MW	406 MW	753 MW	1,312 MW	1,312 MW
Net UFLS tripped as a percentage of contingency size	65%	85%	107%	140%	111%

*A frequency nadir below 47 Hz would likely result in cascading failures to a system black

3.2.3 Sensitivity to upgraded relay configurations

SA Power Networks has indicated that after upgrades to a portion of its UFLS relay fleet, the total time for those relays to respond to under-frequency will be reduced as summarised above in Table 6. The previous case study was remodelled with the improved timing of new relay configurations applied to all relays in South Australia (note that SA Power Networks' planned works will only upgrade a proportion of these relays, so this represents a "best case" beyond planned works).

The results are shown in Figure 6 and summarised in Table 9, and indicate there is a potential improvement in UFLS function. By reducing the response time of the relays, the performance of the UFLS scheme is improved at 3 Hz/s (no overshoot and no excessive load tripping observed). For the 4 Hz/s case, the frequency nadir still falls below acceptance criteria (indicating a fail scenario), but overshoot and excessive tripping are not observed.

Figure 6 Outcomes for varying RoCoF levels with upgraded relay capability

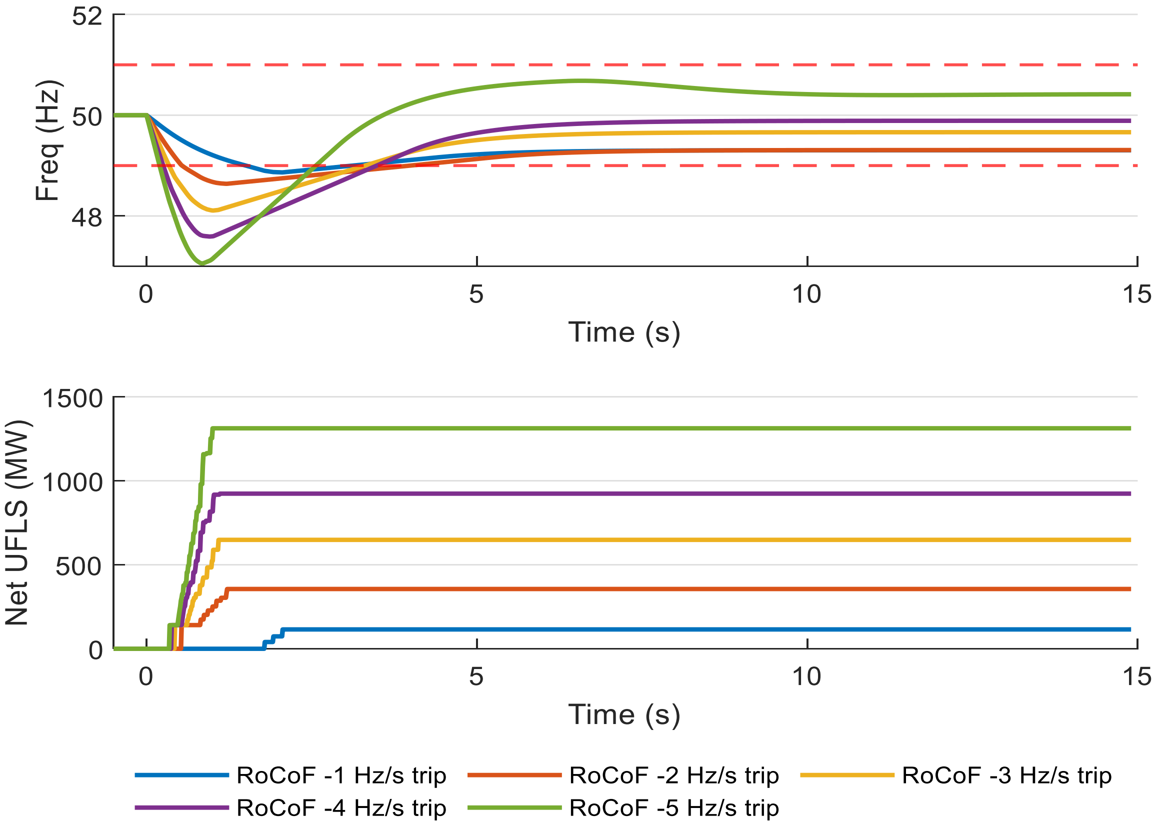


Table 9 Summary of outcomes for varying RoCoF levels with upgraded relay capability

Maximum RoCoF (moving average measured over a 300ms window)	-1 Hz/s	-2 Hz/s	-3 Hz/s	-4 Hz/s	-5 Hz/s
Contingency size (HIC imports + IBR station trip)	235 MW	475 MW	705 MW	940 MW	1,185 MW
Frequency nadir	48.9 Hz	48.6 Hz	48.1 Hz	47.6 Hz	47.1 Hz
Frequency zenith post contingency	49.3 Hz	49.3 Hz	49.7 Hz	49.9 Hz	50.7 Hz
Frequency of lowest UFLS block triggered	48.9 Hz	48.7 Hz	48.2 Hz	47.7 Hz	47.5 Hz
Net UFLS load tripped	115 MW	356 MW	648 MW	923 MW	1,312 MW
Net UFLS tripped as a percentage of contingency size	49%	75%	91%	98%	111%

3.2.4 Sensitivity to no battery droop response headroom

The case study was run again with the available droop response headroom reduced from 150 MW to 0 MW in the South Australian island to investigate the impact of battery droop response on the UFLS performance. The droop response footroom was kept at 120 MW. The results presented in Figure 7 and summarised in Table 10 indicate that the droop response has a significant influence by both improving the frequency nadir and assisting in the management of overshoot following recovery.

All cases run without any droop response resulted in a lower frequency nadir and increased overshoot following recovery exceeding 50.5 Hz in all cases. The droop response is sufficiently fast to assist with the initial frequency arrest. In addition, the droop response assists in managing positive RoCoF as the frequency recovers toward

50 Hz resulting in less overshoot. This proves that an energy injection from a fast battery droop response can assist in resisting the RoCoF and better manage overshoot.

Figure 7 Outcomes for varying RoCoF levels with no battery headroom

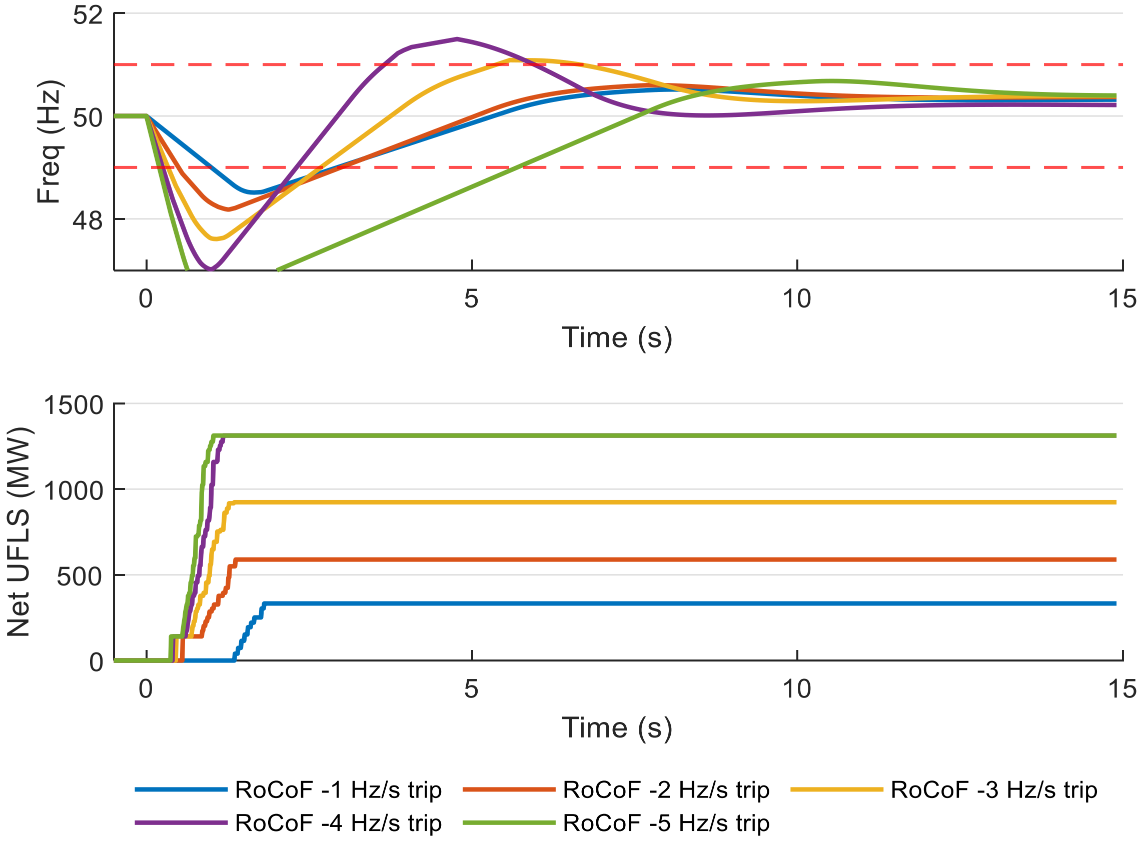


Table 10 Summary of outcomes for varying RoCoF levels with zero battery headroom

Maximum RoCoF (moving average measured over a 300ms window)	**-1 Hz/s**	**-2 Hz/s**	**-3 Hz/s**	**-4 Hz/s**	**-5 Hz/s**
Contingency size (HIC imports + IBR station trip)	235 MW	475 MW	705 MW	940 MW	1,185 MW
Frequency nadir	48.5 Hz	48.2 Hz	47.6 Hz	47.0 Hz*	46.4 Hz*
Frequency zenith post contingency	50.5 Hz	50.6 Hz	51.1 Hz	51.5 Hz	50.7 Hz
Frequency of lowest UFLS block triggered	48.6 Hz	48.3 Hz	47.7 Hz	47.5 Hz	47.5 Hz
Net UFLS load tripped	333 MW	589 MW	923 MW	1,312 MW	1,312 MW
Net UFLS tripped as a percentage of contingency size	142%	124%	131%	140%	111%

*A frequency nadir below 47 Hz would likely result in cascading failures to a system black

3.2.5 Sensitivity to varied UFLS load availability

Load varies from period to period, which means that the amount of net load on UFLS circuits varies from period to period. UFLS schemes must be designed with settings on these circuits to arrest frequency and avoid overshoot appropriately under a wide range of possible system load conditions.

To investigate the impact of varying levels of net UFLS load availability on performance, two additional case studies were run. Periods were chosen with higher and lower levels of UFLS load availability (compared with the base case above). Both cases have no distributed PV generation, and similar synchronous unit dispatch to allow for a meaningful comparison. Details are summarised in Table 11. The different operational demand levels result in different amounts of load on each UFLS frequency band.

Table 11 Pre-disturbance case study parameters

Parameter	Lower UFLS availability	Higher UFLS availability
Distributed PV generating	0 MW	0 MW
Net UFLS available	1,060 MW	1,661 MW
Operational demand	1,211 MW	1,971 MW
FFR Available (headroom/footroom)	150/120 MW	150/120 MW
HIC imports into SA	260 MW	260 MW
System inertia	5,861 MWs	5,861 MWs
Relay timing	Current capability	Current capability

The results from the two cases are presented in Figure 8 and summarised in Table 12. Periods with lower UFLS availability resulted in a lower frequency nadir in all cases, but reduced frequency overshoot was observed. Conversely, in high UFLS availability periods, a higher frequency nadir was maintained in all cases but the larger UFLS block sizes caused excessive UFLS load to be shed in more cases resulting in poorer overshoot outcomes. These results suggest that for RoCoF of -3 Hz/s the outcome is heavily dependent on the amount of UFLS load available.

Figure 8 Outcomes for varying RoCoF levels with lower and higher UFLS availability

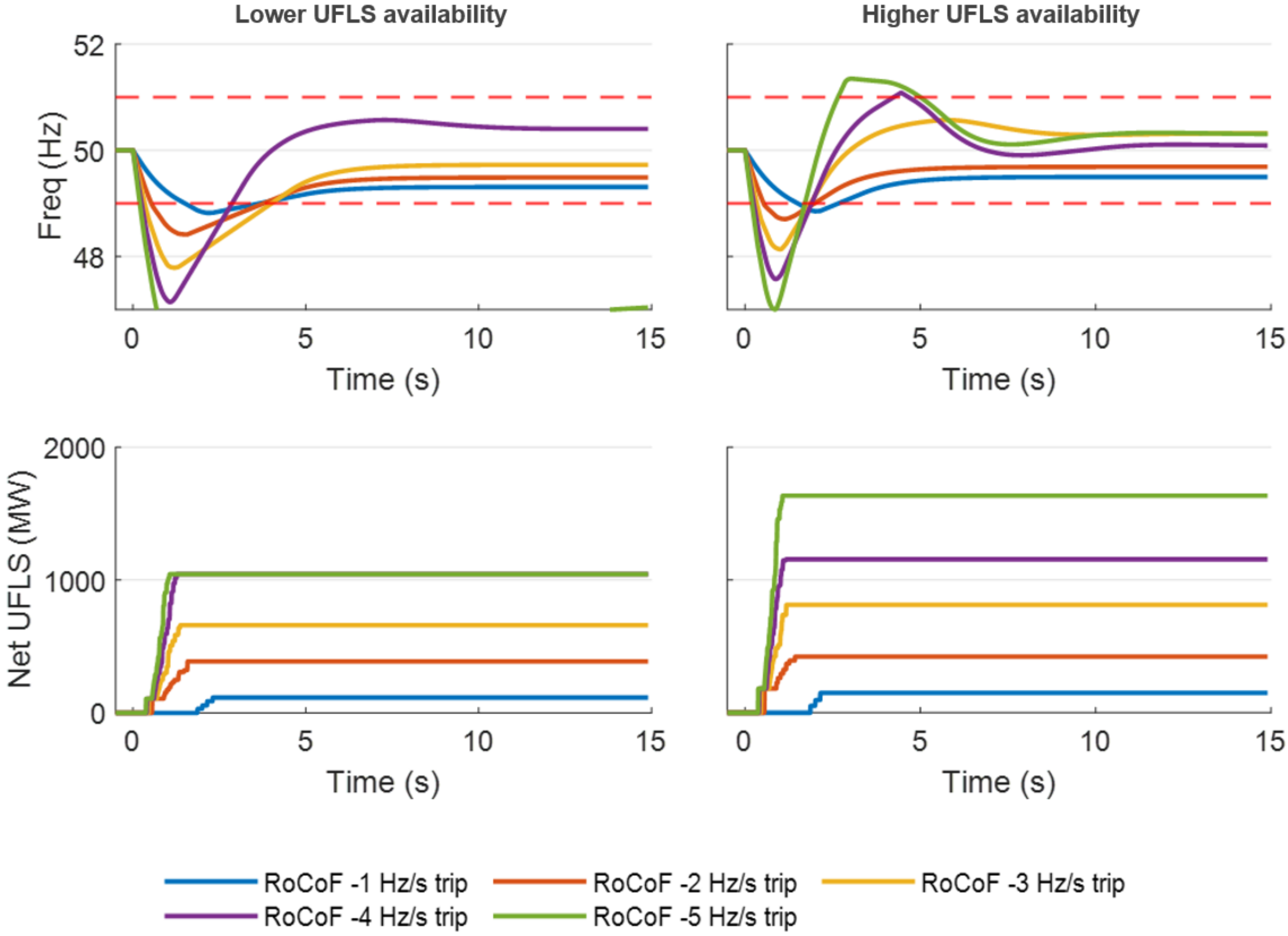


Table 12 Summary of outcomes for varying RoCoF levels with low and high UFLS availability

Maximum RoCoF (moving average measured over a 300ms window)	-1 Hz/s		-2 Hz/s		-3 Hz/s		-4 Hz/s		-5 Hz/s	
Contingency size (HIC imports + IBR station trip)	**235 MW**		**475 MW**		**705 MW**		**940 MW**		**1,185 MW**	
UFLS availability	Low	High	Low	High	Low	High	Low	High	Low	High
Frequency nadir (Hz)	48.8	48.9	48.4	48.7	47.8	48.1	47.1	47.6	46.5*	47.0*
Frequency zenith post contingency (Hz)	49.3	49.5	49.5	49.7	49.7	50.6	50.6	51.2	47.0*	51.3
Frequency of lowest UFLS block triggered (Hz)	48.8	48.9	48.5	48.7 5	47.9	48.2	47.5	47.7	47.5	47.5
Net UFLS load tripped (MW)	116	149	387	422	659	813	1,044	1,155	1,044	1,633
Net UFLS tripped as a percentage of contingency size	49%	63%	81%	89%	93%	115%	111%	122%	88%	138%

*A frequency nadir below 47 Hz would likely result in cascading failures to a system black

3.2.6 Sensitivity to pre-contingency inertia

Power system inertia can also affect UFLS performance. To explore this, a sensitivity was run with synchronous dispatch resulting in almost twice the level of inertia as the base case above. Other parameters were maintained at similar levels (shown in Table 13) to allow direct comparison. The contingency size in each case was increased to achieve the same level of RoCoF for comparison purposes. Due to the higher inertia, achieving a RoCoF of -4 Hz/s or larger would require a total contingency size greater than 100% of demand which is not feasible so these cases have been excluded.

Large contingencies in high inertia periods may also include loss of system inertia (due to trip of a synchronous generating unit), however, for this study inertia has been kept constant to assess its impact.

Table 13 Pre-disturbance case study parameters for high inertia case

Parameter	Value
Distributed PV generating	0 MW
Net UFLS available	1,311 MW
Operational demand	1,512 MW
HIC imports into SA	130 MW
System inertia	10,337 MWs
FFR available (headroom/footroom)	150 / 120 MW

The results are presented in Figure 9 and summarised in Table 14. The 1 Hz/s and 2 Hz/s cases meet the acceptance criteria, but the 3 Hz/s case shows frequency falling below the minimum threshold (likely a failure case).

Figure 9 Outcomes for varying RoCoF levels with higher system inertia

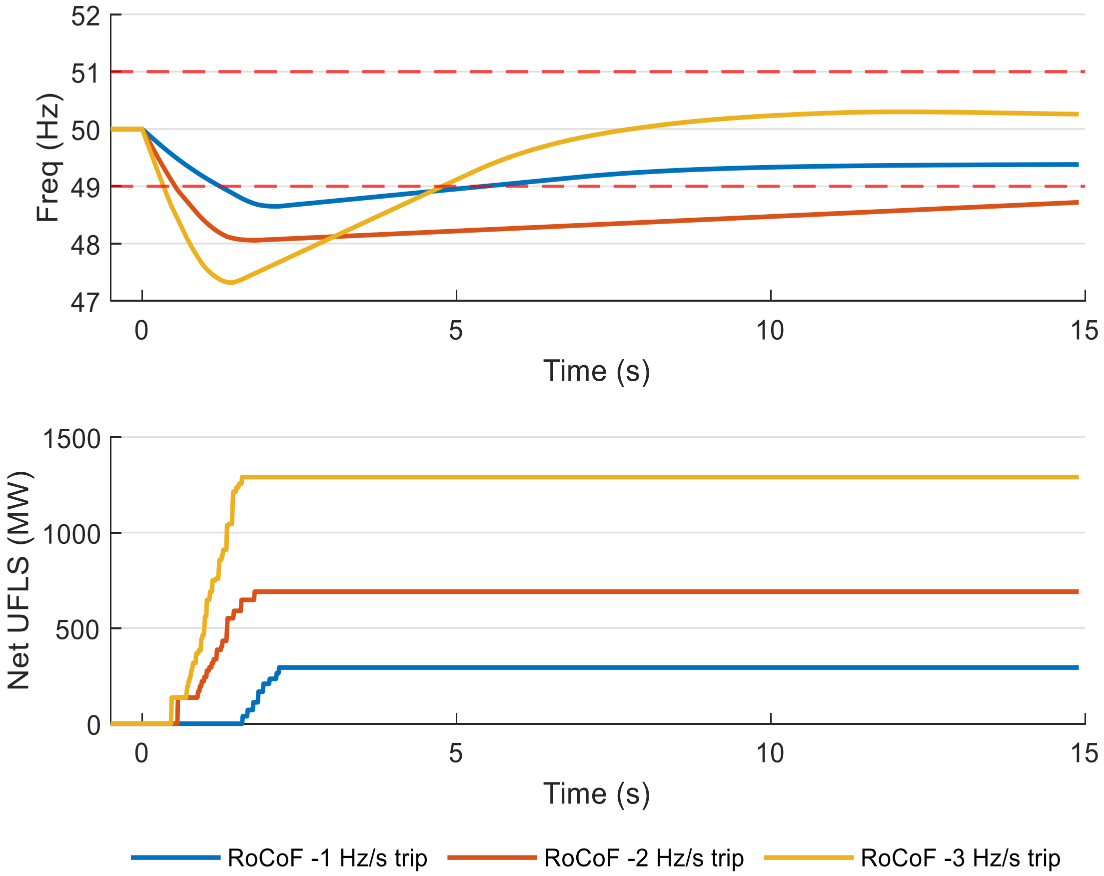


Table 14 Summary of outcomes for varying RoCoF levels with higher system inertia

Maximum RoCoF (moving average measured over a 300ms window)		**-2 Hz/s**	**-3 Hz/s**
Contingency size (HIC imports + IBR station trip)	400 MW	820 MW	1,230 MW
Frequency nadir	48.6 Hz	48.0 Hz	47.3 Hz
Frequency zenith post contingency	49.4 Hz	48.7 Hz	50.3 Hz
Net UFLS load tripped	294 MW	691 MW	1,291 MW
Net UFLS tripped as a percentage of contingency size	74%	84%	105%

3.2.7 Summary of findings

This study suggests that UFLS schemes:

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

It is noted that the model applied for these studies is a simple multi-mass model, which does not account for voltage and reactive power effects or system strength effects, and that these are likely to be significant in the kinds of major power system disturbances that would lead to extreme RoCoF levels in this range.

When RoCoF exceeds 2 to 3 Hz/s, a number of other factors heavily influence the adequacy of the scheme including UFLS availability, battery droop headroom and the level of system inertia. Pre contingent inertia combined with a post contingent energy injection from a fast battery droop response can assist in resisting the RoCoF and better managing overshoot. To this point, a RoCoF standard could be used to determine Inertia and very fast FCAS volumes in each region and across the NEM.

Improved timing capability of UFLS relay configurations may provide a slight improvement in the scheme's performance under high RoCoF, but generally requires replacement of relays.

The case study represented here is focused on a non-credible separation of South Australia leading to electrical islanding of South Australia. Exact time delays and relay settings are different in each NEM region, though in a similar range. If similar levels of RoCoF are experienced in other NEM island regions or in the interconnected NEM (noting this would require very low inertia levels and a large contingency size) then it is reasonable to expect that similar technical limitations and trends would likely apply.

Although not explicitly investigated in this analysis, it is expected that similar limitations are likely to apply to OFGS schemes under high RoCoF conditions during over frequency events. The limitations of disconnection times and coordination of settings becomes challenging at high RoCoF with high potential for over action resulting in overshoot or insufficient time to arrest frequency within acceptable limits.

3.3 Measurement of RoCoF

3.3.1 Measuring RoCoF

Specifying the measurement window over which RoCoF is measured is important. AEMO generally applies measurement windows in the range 100 ms to 500 ms (often using 300 ms for analysis of larger non-credible events that can lead to extreme RoCoF).

The measurement window that is appropriate depends on the intended purpose. Very short measurement windows will tend to capture the effects of very short duration frequency transients which can potentially result in very high RoCoF measurements. This should be avoided when defining minimum measurement windows for protection and UFLS/OFGS relays (to avoid spurious tripping).

Shorter measurement windows may be more appropriate when considering larger (non-credible) contingency events with higher RoCoF, due to the following factors:

- Some relevant events (such as operation of various control or protection schemes affecting system frequency) occur in very short timeframes, necessitating a shorter measurement window to meaningfully capture the effects of these control schemes. For example, for analysing or designing the behaviour of a control scheme operating in a total timeframe of 200 ms during extreme RoCoF events, measuring average frequency over a 300 ms rolling window would not provide an accurate or useful average.
- During a slower RoCoF event, units may need to ride-through a longer duration of frequency change, whereas in a higher RoCoF event, frequency will reach low thresholds much more rapidly, so the ride-through duration requirement is shorter.

For example, when requesting information from generating units on RoCoF withstand capabilities, AEMO suggested targeting analysis around the indicative ride-through durations summarised in Table 15.

Table 15 Indicative durations for understanding RoCoF withstand of generating units

Rate of change of frequency	Durations
>4 Hz/s	>0.1 s
	>0.25 s
>3 Hz/s	>0.25 s
	>0.5 s
	>1 s
>2 Hz/s	>0.25 s
	>0.5 s
	>1 s
>1 Hz/s	>1 s
	>2 s

The most appropriate measurement window could also vary during an event; for example, a short window may be more suited to measuring RoCoF during the initial inertial response, and wider windows could be applied in the recovery phase as proposed by ENTSO-E in its January 2018 Rate of Change of Frequency (RoCoF) withstand capability paper[13].

The RoCoF experienced at different locations in the network may also vary in the immediate period following a large contingency event. In defining RoCoF ride-through requirements for generating units, this needs to be defined based on the local frequency conditions a generating unit may experience at the generator terminals, including possible effects of frequency transients that can be experienced differently at different locations in the network.

Protection and control schemes must use appropriate measurement windows to avoid incorrect operation due to localised short duration frequency transients. The importance of allowing a sufficient sampling window time to account for this, and the risks of erroneous RoCoF measurements over short time durations are summarised in detail in GE's advice to AEMO[14].

3.4 Role of RoCoF limits in the operation of the power system

3.4.1 Credible contingency events

RoCoF limitations for credible contingency events need to consider the upcoming introduction of FFR markets, comprising very fast raise and very fast lower FCAS. AEMO has completed a review and consultation on proposed amendments to the market ancillary services specification (MASS) to include the new services. The MASS amendments, after market consultation, were published on 7 October 2022[15] and will take effect from 9 October 2023 when the new services commence operation. The new very fast FCAS is to be defined as the response to a frequency change at a ramp rate of 1 Hz/s.

[13] At https://docstore.entsoe.eu/Documents/Network%20codes%20documents/NC%20RfG/IGD_RoCoF_withstand_capability_final.pdf.

[14] GE Energy Consulting report to AEMO (9 March 2017) Technology Capabilities for Fast Frequency Response, Section 2.2.2.2 – RoCoF detection, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/reports/2017/20170310-ge-ffr-advisory-report.pdf?la=en.

[15] See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/amendment-of-the-mass/final-determination/final-determination.pdf?la=en.

It should be noted that for contingency events with extreme RoCoF, dispatching greater quantities of very fast raise or very fast lower services will not necessarily result in better frequency performance. All FCAS are designed to deal with particular frequency behaviours and will be ineffective for dealing with conditions too far outside those behaviours.

The presence of a RoCoF standard for credible contingency events will enable a pre contingent volume of inertia and post contingent volume of very fast FCAS to be determined. AEMO continues to research the application and benefits of physical and synthetic inertia and further work is required on this subject. Studies in Section 3.2.4 (Sensitivities to RoCoF with no Battery droop response headroom) showed that an injection of energy post the event can contribute to reducing the RoCoF.

3.4.2 Non-credible contingency events

The analysis in Section 3.2 suggests that emergency frequency control schemes such as UFLS will not operate successfully to arrest a frequency decline for extreme RoCoF levels (indicatively beyond 2-3 Hz/s).

Under the present FOS and NER framework, AEMO does not typically take actions to manage non-credible contingency events unless they are a protected event. However, there may be value in the transparency offered by defining "reasonable endeavours" RoCoF limits which recognise the limits of emergency frequency control schemes beyond 2-3 Hz/s.

3.4.3 Protected events

AEMO cautions against specifying a prescribed RoCoF limit for all protected events. This might overly prescribe the limit that must be adhered to, even where available evidence suggests that a faster RoCoF threshold may suitably manage risk under certain conditions. This may make it impossible to design suitable management actions that can demonstrate a positive cost/benefit assessment, because the FOS requires excessive management action that is not justified by the estimated risks. The result would be that a protected event could not be declared, and no management action could be taken, even where certain actions (requiring less intervention) to mitigate the most significant identified risks may pass a cost/benefit assessment.

3.5 AEMO advice for RoCoF limits on the power system

3.5.1 RoCoF limits for credible contingencies in normal and island operation - Mainland

Studies completed by AEMO in detail over many years indicate that:

- AEMO investigations reveal that there is not much known about the withstand capabilities of some thermal generator technologies beyond 1 Hz/s.
- Experiences in the NEM from actual events where generators successfully ride through RoCoF of up to +/-1.2 Hz/s.
- Distribution-connected inverters have been bench tested with the majority of inverter types in Australia proven not to have any settings that would disconnect the inverter due to RoCoF less than +/-4 Hz/s.
- Investigations reveal that Australian inverter types do not have the loss of mains issue that was found in inverters in the UK and Ireland.

AEMO advises for credible contingencies on the mainland:

The FOS should include a limit for RoCoF of 1 Hz per second, measured as up to 0.5 Hz change over any 500 ms period (1Hz/s).

3.5.2 RoCoF Limits for Tasmania

The Tasmanian power system differs from the mainland in many aspects, introducing its own frequency control complexities. This often results in separate, independent FOS requirements applicable to Tasmania's unique scenario. Specific characteristics of the Tasmanian power system impacting frequency control and RoCoF are:

- Basslink can be a high percentage of the Tasmanian load / generation mix. Imports and exports on Basslink can be up to 480 MW and 500 MW respectively (the original interconnector design allowed for up to 630 MW export to the mainland), with a typical Tasmanian minimum load of 900 MW (56%) and maximum load of 1,790 MW (28%).
- The geographically compact nature of the Tasmanian power system means that fault events are observable right across the transmission network. This increases the likelihood that a high percentage of IBR, including wind and solar generation, will simultaneously enter fault ride-through (FRT) thereby contributing to increased RoCoF experienced during under frequency events.
- Loss of Basslink is always a credible contingency event, which for many system operating conditions, can impact on the Tasmanian network with a RoCoF greater than 1 Hz per second following an unplanned disconnection from Victoria.
- The simultaneous loss of a Tasmanian generator in conjunction with Basslink is currently reclassified as a credible contingency event whenever Basslink is importing to Tasmania. This means that Tasmania must currently source its own FCAS during periods of import. This situation will remain until the technical issues justifying the reclassification can be satisfactorily resolved.
- Tasmania is predominately hydro powered. Hydro units can typically withstand higher RoCoF and are generally less susceptible to mechanical fatigue and potential damage compared to thermal generators. However many units have relatively slow (speed) governing responses, due primarily to hydraulic limitations, which limit their initial ability to control frequency excursions following contingency events. As a result of hydro governing characteristics, Tasmania was the first NEM region to have FCAS requirements calculated as a function of available inertia.
- Raise and lower FCAS availability can be scarce in Tasmania, especially for the fast (6-second) and slow (60-second) services. Often during high wind periods that correspond with Basslink import, hydro plants are run on minimum generation to provide raise services, but are unable to further reduce their output to provide lower FCAS.
- There are many bespoke frequency control and protection schemes in place in Tasmania to manage generation and transmission contingencies, including the credible loss of Basslink. These schemes operate outside of the NEM's FCAS markets to satisfy the FOS.
- Tasmania has complicated, well designed emergency frequency control (EFC) protection schemes for the management of both severe under and over frequency events. The discrimination logic in both the UFLS scheme and OFGS scheme use a combination of RoCoF and absolute frequency triggers which are designed to specifically manage high RoCoF events.
- TasNetworks presently implements RoCoF constraints in the Tasmanian power system to maintain system security following credible contingency events. The design of the UFLS and OFGS schemes have also taken

into consideration specific non-credible contingency events, many of which are required to be assessed to satisfy Tasmanian legislative requirements[16]. The unique characteristics of the Tasmanian power system as outlined above, have all been considered in the RoCoF solutions which have been deployed by TasNetworks thus far.

Specifically, the context is:

- The Tasmanian UFLS is normally expected to disconnect load between 47 Hz and 48 Hz which align with the extreme frequency excursion tolerance limits. However, to help manage high RoCoF events that would otherwise result in a loss of UFLS discrimination, pre-emptive load shedding can also occur between 48 Hz and 49 Hz when the RoCoF is sufficiently high. EFC load shedding can therefore occur within the operational frequency tolerance band.
- To avoid the unwanted disconnection of consumers for credible events such as the loss of Basslink, it therefore becomes necessary to ensure that RoCoF is managed below the UFLS trigger settings for normal system operation. The activation of EFC schemes is not an acceptable outcome for credible contingency events. This is achieved via dispatch constraints which are a function of Tasmanian inertia and contingency size (including transient FRT contributions from IBR equipment).
- A similar concept has been applied in the design of the Tasmanian OFGS scheme. However, there has not been a need to implement RoCoF based generator tripping within the operational frequency tolerance band given the much wider over frequency limits available for emergency control purposes (52.0 Hz to 55.0 Hz).
- Even with this complexity, there are still some non-credible contingencies that will result in high RoCoF and/or voltage collapse that will likely result in a black system. It is not practical or efficient to design EFC schemes to control the outcomes of all possible non-credible contingencies which could occur under any system operating condition.
- A number of special control schemes are used to reduce contingency sizes to help manage FCAS requirements in Tasmania. The Basslink Frequency Control System Protection Scheme (FCSPS) is specifically designed to manage the credible loss of Basslink (both for import and export conditions), while two Generator Contingency Schemes (GCS) have so far been implemented to satisfy the 144 MW generator contingency limit defined in the FOS.
- RoCoF in Tasmania has traditionally been managed to a limit of 3 Hz per second, originally corresponding to the setting of early wind farm anti-islanding schemes. In more recent years, the 3 Hz per second threshold has been widely provided to developers of distributed energy resources (DER) as the basis for anti-islanding scheme designs, especially for synchronous machine installations including mini-hydro and methane recovery units.

In Tasmania, the present RoCoF management approach is:

- Dispatch constraints are used to limit peak ROCOF to no more than 3 Hz per second following any credible contingency event. The constraints are also designed to prevent operation of the UFLS for contingencies that should be managed via available FCAS, noting that such requirements may change over time as scheme designs evolve.

[16] Specifically the Network Planning Requirements defined in the Electricity Supply Industry Regulations, at www.legislation.tas.gov.au/view/html/inforce/current/sr-2018-002#GS5@EN.

- For such analysis, TasNetworks current approach is to calculate RoCoF using a 250 ms moving average window which has the effect of averaging instantaneous calculations of RoCoF over a 250 ms time period.
- The UFLS scheme uses relays capable of implementing 'frequency supervised average rate of change of frequency' protection which relies on a similar principle to that described above to remove 'inherent noise' in RoCoF measurements. At present, the first two UFLS load blocks use a Df/Dt setting of 0.4 Hz / 340 ms, with threshold settings of 49.0 Hz and 48.6 Hz. The calculation of RoCoF only commences once the threshold setting has been reached, with a relay trip occurring if frequency has fallen by more than 0.4 Hz within the 340 ms measurement window.
- The UFLS scheme also implements 'traditional' definite time under frequency tripping within the range 47.0 Hz and 47.96 Hz, with load distributed across eight setting groups. This allows for a commensurate UFLS response depending on the severity of the network disturbance, with setting discrimination and load block sizes designed to minimise the risk of excessive frequency rebound (above 50 Hz).
- The OFGS scheme uses the same relays as the UFLS with a similar design philosophy. Frequency supervised RoCoF protection is used in parallel with definite time elements to enable better discrimination to be achieved, thus minimising the risk of frequency undershoot following EFC scheme activation.

The processes described above are designed to automatically sense a fast RoCoF event and accelerate mitigating actions to provide the network with the best chance of being controlled and returned to a stable operating condition.

AEMO considers this to be a very successful, proven, well designed and prudent approach to the management of frequency in the Tasmanian system.

AEMO recommends that the Tasmanian RoCoF for credible events be limited to ±3 Hz per second measured as not exceeding a 0.75 Hz deviation over any 250 ms averaging time period.

3.5.3 Non-credible contingencies on the mainland and in Tasmania

Non-credible contingencies have infinite possibilities and by nature cannot all be planned for. The NER allows for the enablement of UFLS and OFGS schemes as a final resistance to rapid imbalance of supply and demand. As such, reasonable endeavours should apply to any requirement specifying the outcome of a non-credible event.

Considering:

- In the mainland, the UFLS commences at 49 Hz, and;
- Studies have shown that UFLS will operate consistently well in RoCoF up to 2 Hz/s and is not reliable beyond 3 Hz/s

Therefore,tTo utilise a reasonable endeavours approach for non-credible contingencies, a RoCoF limit of +/- 3 Hz/s, measured at around 49 Hz, will enable enough time for the UFLS to operate effectively. To measure at approximately 49 Hz, AEMO recommends that RoCoF should not exceed 0.9 Hz over any 300 ms period. It is noted that extreme non-credible events can occur and may not all be manageable.

For Tasmania, a dynamic RoCoF protection response has been implemented to not breach 3Hz/s. As such, it is advised that the same non-credible RoCoF limit for the mainland, based on a reasonable endeavours approach, can also be applied in Tasmania.

AEMO advises that the FOS should include a reasonable endeavours RoCoF limit of 3 Hz/s measured as no more than 0.9Hz over any 300 ms period (3 Hz/s) for non-credible contingency events on <u>both the mainland and Tasmania.</u>

3.5.4 Protected events

AEMO does not recommend a RoCoF limit in the FOS for protected events. Instead, AEMO proposes that RoCoF limits for protected events be applied on a case-by-case basis during the establishment of each protected event.

4 Settings for contingency events

This section provides advice on the settings in the FOS for contingency events and examines:

- Whether the existing frequency containment and recovery bands that apply for credible generation, load and network events remain fit for purpose, in particular:
  - Opportunities to improve the clarity and consistency of settings in the FOS for credible events.
  - The appropriate setting for the operational frequency tolerance band that applies during conditions of supply scarcity, noting that stakeholders have suggested that the current setting of 48-52 Hz places an excessive obligation for connecting generators through the application of NER clause S5.2.5.3.
- Whether the existing frequency containment and recovery bands that apply for non-credible contingency events and protected events remain fit for purpose. AEMO's advice is requested on opportunities to improve the clarity and consistency of settings in the FOS for non-credible events.
- The inclusion in the FOS of limits for the maximum size of credible contingency events for the Tasmanian region. This includes advice on:
  - Whether the existing limit of 144 MW for the largest allowable generation event in the Tasmanian region and system remains appropriate. This includes an assessment of the system security and operational implications of raising this limit to 155MW, as proposed by Woolnorth Renewables.
  - Whether the generation limit in Tasmania should be extended to apply to network and load events. In its submission to the issues paper, TasNetworks expresses support for the application of a similar limit for the largest load event in Tasmania.
- Whether the FOS should include a limit on the maximum credible contingency event for the mainland system and whether such a limit should apply for generation, load and/or network events.

Relevant factors and operational experience that AEMO has considered in relation to contingency event settings are examined in section 4.1. AEMO's advice on these matters is brought together in Section 03.5.

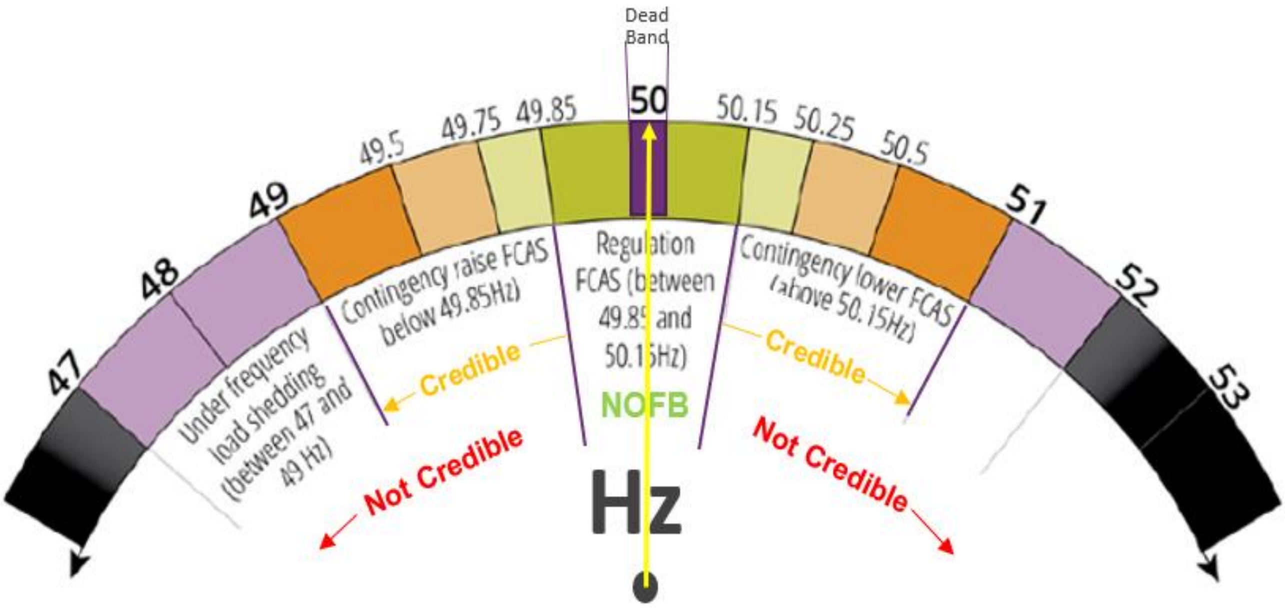
4.1 AEMO implementation of the FOS for contingency events

The NER separate contingency events into credible, non-credible and, under some conditions, protected. The FOS specifies minimum acceptable power system frequency outcomes for each type of event. The parameters specified in the FOS for the contingency band are referenced in the MASS which outlines the specification for the provision of FCAS. All FCAS providers register in the FCAS markets with settings in accordance with the MASS, determined from the FOS.

Modifying the FOS would not, by itself, either increase power system resilience or increase the effective control of power system frequency under normal conditions. Changes to all ancillary service registrations would be required and thousands of constraints would need to be updated to implement any FOS changes in the NEM and unit settings would be required to be completed in a co-ordinated manner for physical implementation on the power system.

AEMO does not see any need for change, particularly when in context of the considerable undertaking and volume of work a change would create for the industry.

Figure 10 Frequency control bands in the NEM – contingency bands



4.1.1 Credible contingency events

Credible contingency events are managed by contingency FCAS reserves for frequency deviations outside the NOFB. Proportional or switched controllers respond when frequency reaches the edge of the NOFB at 49.85 Hz or 50.15 Hz. Contingency FCAS is designed to re-balance the supply and demand rather than actively controlling frequency back to 50 Hz.

Contingency FCAS is enabled through dispatch instructions, allocating headroom and foot room to cover credible contingencies. Raise and lower services which act over very fast (1 second)[17], fast (6 seconds), slow (60 seconds) and delayed (5 minutes) timeframes.

AEMO's advice in Section 3 of this document recommends the introduction of a RoCoF limit in the FOS. AEMO considers that the introduction of a RoCoF limit be given time to settle into the NEM and integrated operationally before also changing other critical settings used to oppose frequency changes following disturbances.

Management of contingency events has been integrated into FCAS provider registrations and unit parameters over many years, with no current or anticipated issues. AEMO therefore sees no need for changes to the FOS for management of contingency events on the mainland or in Tasmania in this review.

4.1.2 Non-credible contingency events

In addition to contingency FCAS for credible events, emergency control settings act as a backstop for more severe, non-credible events. The emergency frequency control schemes in the NEM are UFLS and OFGS, in addition to emergency controls that may be installed by network service providers under NER S5.1.8. Emergency frequency control schemes are intended to minimise the risk of cascading failure associated with significant multiple contingencies, but do not guarantee that a cascading event will be stopped in any given conditions.

It is expected that UFLS and OFGS will not be triggered for credible contingency events. To be certain of this, AEMO must have confidence that all controls in place with a role in power system frequency control are

[17] FFR implementation due October 2023.

co-ordinated, tuned and designed to operate correctly. As such, any modification to the contingency bands in the FOS must be designed amongst all parameters across the range of NEM frequencies.

AEMO has not identified a need to change the FOS settings for management of non-credible contingency events on the mainland or in Tasmania in this review, and recommends that sufficient time is allowed to assess the impact of any RoCoF limit (if implemented) before reconsidering the need for any further settings changes.

4.1.3 Credible contingency events during supply scarcity conditions

'Supply scarcity' is defined in the FOS as the condition where load has been disconnected either manually or automatically, other than in accordance with dispatch instructions or service provision, and not yet restored to supply.

Settings for credible contingency events that occur during 'supply scarcity' were initiated from the system separation and load shedding event in Victoria on 16 January 2007. During this event, NEMMCO delayed restoring load until FCAS was available from generators within Victoria to maintain the FOS for a credible event. At this time FCAS support was not available from neighbouring regions and UFLS load was already shed.

The Australian Energy Regulator (AER) investigation recommended NEMMCO refer clarification of the FOS for periods of "Supply Scarcity" to the Reliability Panel. This formed part of the 2009 FOS review.

The NEMMCO incident report, AEMC Reliability Panel 2009 FOS review Final determination report[18] and the AER investigation report [19]were all reviewed to establish the context.

In the 2009 FOS review, the Reliability Panel, on the advice of NEMMCO reviewed the application of FOS for events during load restoration following a contingency event. The context of the FOS review of 'supply scarcity' throughout the 2009 Reliability Panel review is explained as 'a generation event, load event or separation event during load restoration following a contingency event'.

The technical requirements for the 'supply scarcity' frequency band are sound and required. That is, during load restoration following a contingency event, meaning:

1. A significant contingency event has occurred. FOS applied to the event, applicable for the event.
2. There was considerable load shedding as a result of the contingency event.
3. The event has passed and AEMO is restoring the power system so load can be re-connected and the 'supply scarcity' FOS applies from this point, until the system is restored.

Essentially the 'supply scarcity' frequency band applies during a restoration of the system. During this time a contingency event can occur, though AEMO may not have all desired FCAS and UFLS / OFGS capability available, hence a wider band is required to account for the conditions and scenario during a system restoration.

Table A5 in the FOS (Summary of mainland system frequency outcomes during supply scarcity) reflects the parameters that apply after an event that has led to load shedding, until all load is restored. These settings allow for wider frequency bands during reconnection of load and generation to the system, mindful that the system must remain secure during the process. During a system restoration, the power system is very fragile. AEMO requires that all plant connected to the power system be able to withstand wider than normal operating frequency bands to

[18] See https://www.aemc.gov.au/sites/default/files/content/Frequency-Operating-Standards-%28Mainland%29.PDF.

[19] See https://www.aer.gov.au/system/files/AER%20Investigation%20report%20-%20events%20of%2016%20January%202007%20-%20September%202007.pdf.

avoid disconnection of plant during the restoration. When restoring the system, AEMO operators need to know that plant has been designed to withstand frequency within 48 Hz and 52 Hz in Queensland and South Australia and 48.5 Hz and 52 Hz in New South Wales and Victoria.

AEMO confirms the values for supply scarcity and advises no change to the settings for the operational frequency tolerance band that applies during conditions of supply scarcity.

AEMO observes that there is confusion among industry participants about the application of the supply scarcity FOS settings. AEMO believes this is most likely caused by the term ‘supply scarcity’ which, in the specific definition in the FOS, has a different meaning to both the ordinary English language meaning of the term and the conditions described in NER 3.8.14 for the supply scarcity mechanism. AEMO recommends that the Reliability Panel consider replacing the term “supply scarcity” in the FOS to better reflect the purpose of the settings, namely, to apply during the process of “system restoration”.

As an example, AEMO has been asked why the ‘supply scarcity’ FOS wasn’t being applied during the market suspension period of June 2022 when there was reduced availability of wind, solar, coal, gas and hydro units in the NEM (that is, scarce supply). It has also been pointed out to AEMO on many occasions that it is not possible to have a frequency of 52 Hz (an oversupply) if supply is scarce. AEMO believes that renaming the term ‘supply scarcity’ in the FOS to what it is intended for – “system restoration” – will avoid much confusion.

AEMO recommends renaming ‘supply scarcity’ in the FOS to ‘system restoration’.

4.1.4 Limits on maximum credible generation contingency size in Tasmania

Section 3.5 explained there are unique differences in the Tasmanian power system compared with the mainland. Tasmania requires different FOS parameters to the mainland as they are two very different power systems. Tasmania has a different mix of energy sources, a comparatively very small system size and a proportionally large DC inverter-based interconnection, Basslink.

The Tasmanian power system has specific limitations for contingency FCAS volume. Contingency size is limited by the ability to manage frequency during credible events. AEMO notes that TasNetworks has recently commissioned a second generator contingency scheme to allow all generators in Tasmania to operate unconstrained when there is sufficient load tripping available. Similar schemes and arrangements have been in place for the Tamar Valley 208 MW combined cycle gas turbine for over ten years.

However, when there is not sufficient load available through special contingency schemes, increasing or removing the limit would expose Tasmania to operational risks that cannot be adequately managed at this time. The presence of a contingency size limit in the FOS reflects the direct relationship between contingency size and frequency control in Tasmania.

Tasmania has specific requirements that are not common with the mainland, due to;

- the specific difficulty in managing contingencies in Tasmania,
- scarcity of FCAS volume in Tasmania, and
- presence of a generator contingency scheme which allows constraints to be lifted when contingency FCAS is available

AEMO recommends the contingency limit of 144 MW generation in Tasmania be retained.

4.1.5 Limits on maximum credible load contingency size in Tasmania

The scarcity of resources to actively manage large generation contingencies in Tasmania is also true for large load contingencies. Unlike generation, load size is very difficult to constrain down to reduce contingency risk exposure. Typically loads are on or off. The largest present load in Tasmania managed via FCAS is 120 MW and TasNetworks has advised that a limit of 144 MW to match the generator contingency limit would be manageable.

Contingency events can involve the disconnection of network elements, load or generation. TasNetworks and AEMO must secure the system for all credible contingency events. The loss of the largest single network element, load or generator is credible. AEMO has observed situations in Tasmania where there are restrictions on the ability to provide fast lower FCAS. Future load sizes greater than the present resources can manage would create operational risks that may not be able to be managed prior to the contingency event.

AEMO considers that a limit in the FOS for single credible load and network contingency sizes to match the single credible generation size is appropriate in Tasmania. This will not, of course, limit or prevent load intensive industries from connecting large plants in Tasmania, but the plant design may need to account for separate circuits within the plant to avoid a single point of failure greater than 144 MW from both a load and a network perspective. Alternatively, generator fast inter-tripping schemes could be established, similar to those already used to cater for loss of Basslink during periods of high export from Tasmania towards Victoria.

In considering the load contingency size as it applies in the FOS, AEMO also recommend this applies to network events. In reality, this will apply to all credible contingency events in Tasmania which includes generation events, load events, network events and separation events (as all defined in the FOS).

AEMO advises that a limit of 144 MW apply to all generation, load, network and separation events as defined in the FOS for Tasmania, unless a specific control scheme is in place and implemented by the Tasmanian NSP with the approval of AEMO.

4.1.6 Limits on maximum credible contingency size on the mainland

This section provides advice on whether the FOS should include a limit on the maximum credible contingency event for the mainland system.

As the system transforms, many proponents and developers are seeking to deploy new VRE generators, battery energy storage systems (BESS) and other equipment on the power system including large loads. The mainland power system is different to the Tasmania power system due to its large geographical size and diversity of resources and locational specific parameters across the regions and within regions. AEMO met with TNSPs and observed present processes for determining the limiting contingency sizes during new applications for connection. Discussions revealed that:

- Limiting factors were not always frequency related. Localised sub-regional restrictions were often limited by voltage related matters and there were also thermal limitations in many areas, which would be dealt with using constraints on the dispatch of the plant.
- There is a limit to the capability of FCAS reserves to manage larger contingency events. Large MW contingencies can affect a range of other network operating limits beyond frequency, often in non-linear ways. Such limitations do not readily lend themselves to co-optimisation in dispatch.
- Large generator contingency MW sizes can increase reserve requirements for reliability assessments. This can't be managed in dispatch.

- Use of runback schemes to disconnect VRE to reduce contingency sizes is no longer available in some regions, as the transmission NSPs (TNSPs) have so many runback schemes they are not introducing any more.
- Any contingency size limits due to network hosting capacity will need to be region-specific. A value for South Australia would not be the same as Queensland. Connection size limits due to localised network hosting limitations may also be needed sub-regionally. For example, a contingency limit in outback New South Wales will be different to a contingency limit for Newcastle.
- Contingency limits are not solely based on generation, but also on other aspects including network equipment, and these contingency limits can change as the system changes. For example, in South Australia, DPV disconnection in response to voltage disturbances increases the contingency size in metro areas.
- Contingency limits can also change depending on the part of the network, for example in the above point on South Australian DPV shake off, metro generators may have lower connection point limits than regional South Australia connections.
- For large contingency sizes, sufficient head room needs to be maintained on the interconnectors for the cross regional delivery of FCAS. An alternative to interconnector head room is that generators can be curtailed to reduce contingency sizes.
- Contingency limits and connection point sizes could also vary based on the connection point design, for example a very long line over hundreds of kilometres may have a different cost and risk profile than a 1 km connection.
- The ability for areas of the network to manage large contingencies could change in the future as the NEM becomes more interconnected meaning connection point sizes could be increased on a case by case basis depending on the planned date of connection/commission.

These findings show that it may be difficult for the specification of a limit in the FOS to adequately reflect the geographical variation of the network hosting capacity and how this may change over time. AEMO's view is that it may be more appropriate for operational issues related to the connection of large generators and loads to be managed by AEMO and TNSP directly.

AEMO's NEM dispatch engine is capable of co-optimising energy procurement and FCAS, inherently balancing the contingency size trade off when required. This is often used during network outages, particularly those involving interconnectors, and also for efficiently managing MW contingency risks arising from the action of some generator runback schemes.

In consideration of the points raised by TNSPs, AEMO recognises:

- Each TNSP is best placed to review network hosting limits and contingency sizes in line with each application on a case by case basis.
- A transparent MW credible contingency size limit for the mainland will be of value to guide new project sizing, particularly in the connection process. It is recommended that AEMO and NSPs create transparency through a guideline for connecting participants that outlines network hosting and contingency size limits.

4.2 AEMO advice on settings for contingency events

AEMO's advice for contingency event settings in the FOS is as follows:

- **No change in the contingency bands that apply for credible generation, load, and network events in the FOS.**
- **AEMO confirms that the full range of 48 Hz to 52 Hz in Queensland and South Australia and 48.5 Hz to 52 Hz in Victoria and NEW South Wales is required during system restoration due to the wide range of expected frequency. AEMO also confirms that this range flow through to the standards for connecting generators. As such, AEMO advises no change to the settings for the operational frequency tolerance band that applies during conditions of supply scarcity.**
- **AEMO recommends that the term "supply scarcity" be renamed "system restoration" to reduce confusion about the application of these settings.**
- **No change in the contingency bands that apply for non-credible generation, load, and network contingency events in the FOS.**
- **A limit of 144 MW apply to all generation, load, network and separation events as defined in the FOS and should not exceed 144 MW in Tasmania, unless a specific control scheme is in place and implemented by the Tasmania NSP with the approval of AEMO.**
- **The FOS should not include a limit on the maximum credible contingency event for the mainland system**.

5 Limit for accumulated time error in the NEM

This section provides advice on the FOS limit for accumulated time error across the NEM. The Panel requested that AEMO advise on:

- The security and operational impacts and other related learnings following the Panel's 2017 determination to increase the limit on accumulated time error in the mainland NEM from 5 seconds to 15 seconds.
- AEMO's view on further potential reforms to the limit on accumulated time error, including consideration of potential options including:
  - Maintenance of the current limit on accumulated time error.
  - Removal of the limit on accumulated time error.
  - That the limit on accumulated time error apply over a period of time, rather than being an absolute limit. AEMO's advice is sought on how such a time-based limit on accumulated time error may be set. This may be informed by analysis of the rate of accumulation of time error over time in the NEM and what rate of accumulation is considered to be 'good operating practice'.

Stage One of the 2017 FOS Review examined the time error standard and contemplated relaxing or removing the requirements. That review concluded that the mainland time error requirement would be relaxed from ±5 seconds to the current ±15 second requirement, while the requirement for Tasmania was left unchanged. It was intended that this relaxation would be a checkpoint to gauge impacts, while a subsequent review would review the matter again to see if further change was justified.

Relevant factors and operational experience that AEMO has considered in relation to accumulated time error limits are examined in sections 5.13.1 to 5.8. AEMO's advice on these matters is brought together in Section 5.9.

5.1 Control of time error in the NEM

Time error is used by AEMO in the following ways:

- In the NEM Dispatch Engine (NEMDE) dynamic regulation FCAS constraints[20], where time error is an input to the calculation of the volume of regulation FCAS procured in the mainland[21].
- In AGC, where time error is an input to calculation of an automatic offset from AGC's target frequency. For example, the normal 50 Hz target might be adjusted to 50.02 Hz to correct negative accumulated time error.
- In real time operations, where accumulated time error can result in the following manual actions:
  - The application of a manual offset to AGC's target frequency.
  - A manual reset of time error to zero.
  - Directions to help improve time error (a very rare action).

[20] F_MAIN+NIL_DYN_RREG & F_MAIN+NIL_DYN_LREG

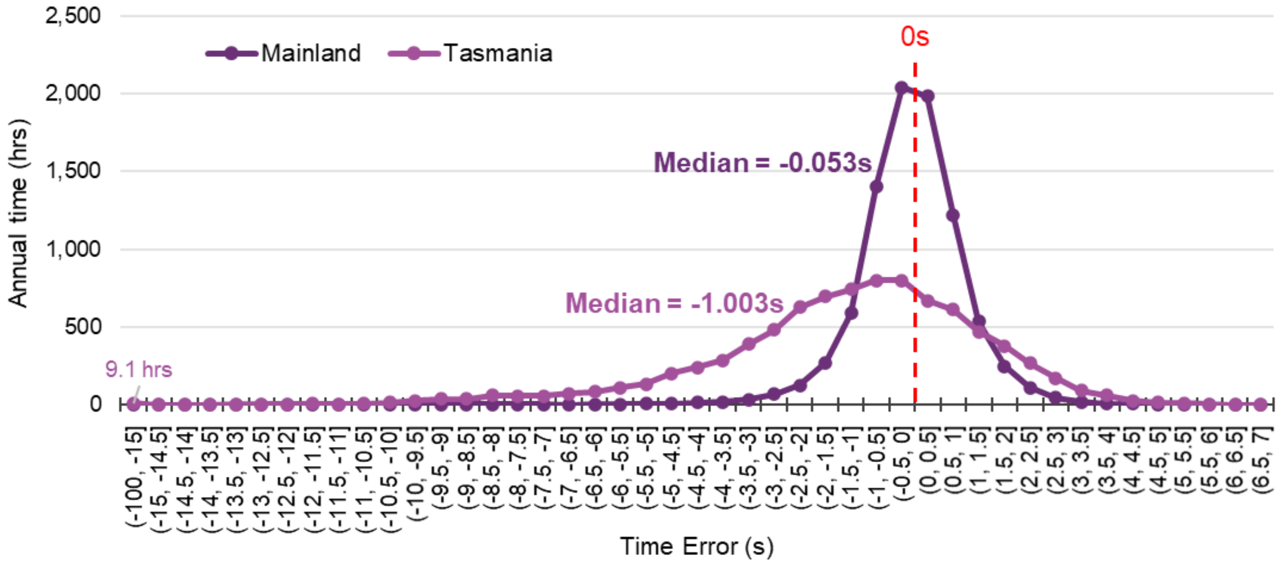
[21] Note that AEMO does not currently link Tasmanian time error to dynamic regulation FCAS procurement.

AEMO observes that time error has remained within the FOS requirement of ±15 seconds in the mainland for FY2022, as seen in the figure below, with the above combination of mechanisms to control time error appearing adequate. Minimal manual intervention was required in FY2022 to manage time error in the NEM mainland.

The distribution of time error in Tasmania is wider than the mainland. Accumulated time exceeded the FOS requirement of ±15 seconds for approximately 9.1 hours in FY2022. AEMO reset the Tasmanian time error to zero on three occasions in FY2022.

There is slight bias towards negative time error in the mainland. This bias is more pronounced in Tasmania.

Figure 11 Time error distribution in FY2022



5.2 Costs associated with time error control in the NEM

Maintenance of time error in the NEM may incur costs through the operation of the previously identified mechanisms. However, it is important not to equate the cost of dynamic regulation procurement with the cost of time error control. Time error control is only one of the reasons for dynamic regulation procurement. AEMO has provided a non-exhaustive examination of the costs of dynamic regulation in this section, noting that it is not feasible to separate the cost of time error control from dynamic regulation procurement.

AEMO does not believe the automatic offset to system base frequency in AGC incurs significant quantifiable costs. This mechanism only increases or decreases the usage of previously procured sources of regulation FCAS, meaning the same cost would be incurred whether or not AEMO makes use of these resources. Furthermore, the manual interventions available to AEMO are used rarely and in limited circumstances which provides confidence that they are unlikely to incur significant additional costs.

AEMO has estimated the cost incurred to procure dynamic regulation FCAS from FY2017 to FY2022 in Table 16[22]. Quarterly total costs and quarterly average costs are also provided in Figures 12-15.

Table 16 Estimated cost of dynamic regulation FCAS procurement FY2017 to FY2022

Financial Year	Estimated cost of dynamic raise regulation	Estimated cost of dynamic lower regulation
FY2017	$1,895,743.11	$870,399.36
FY2018	$2,193,850.23	$775,857.96
FY2019	$15,398,998.67	$1,678,378.36
FY2020	$20,060,711.41	$569,999.89
FY2021	$5,448,405.10	$264,274.62
FY2022	$1,413,946.05	$444,696.20

In AEMO's 2017 advice to the Reliability Panel, this cost was estimated to be 'approximately $1 million per annum'. Since that time, dynamic regulation FCAS costs have increased significantly, particularly in FY2019 and FY2020 where there was markedly poorer frequency performance. This caused higher time error which increased dynamic regulation procurement volumes. Over the same period, regulation FCAS prices were largely constant. Note that over the course of 2019, AEMO increased base regulation volumes significantly (e.g. from 110 MW of Raise Regulation to 210 MW), where they now remain. The costs summarised in the table above do not include the cost of the 'base' volumes.

Estimated costs for FY2022 of approximately $1.9 million per annum are below the FY2017 estimated cost of approximately $2.8 million[23]. AEMO observes that the lower costs reflect better frequency control performance associated with the implementation of mandatory PFR and the significant increase in base regulation volumes, the ongoing cost of dynamic regulation procurement is likely to reflect recent performance.

[22] AEMO estimated this cost in this advice by calculating the RHS of F_MAIN+NIL_DYN_RREG & F_MAIN+NIL_DYN_LREG constraints × average regulation price of mainland regions for each trading interval in each financial year. AEMO has not estimated the increased cost of procuring the base quantity of regulation FCAS due to the merit order price effect of the additional dynamic regulation volume causing a higher regulation price to be applied to the base quantity of regulation FCAS but acknowledges this would lead to a higher estimate.

[23] AEMO used a different calculation method in its advice in 2017, hence the changes in estimate for the same period.

Figure 12 Quarterly dynamic raise regulation procurement enabled amount and estimated cost

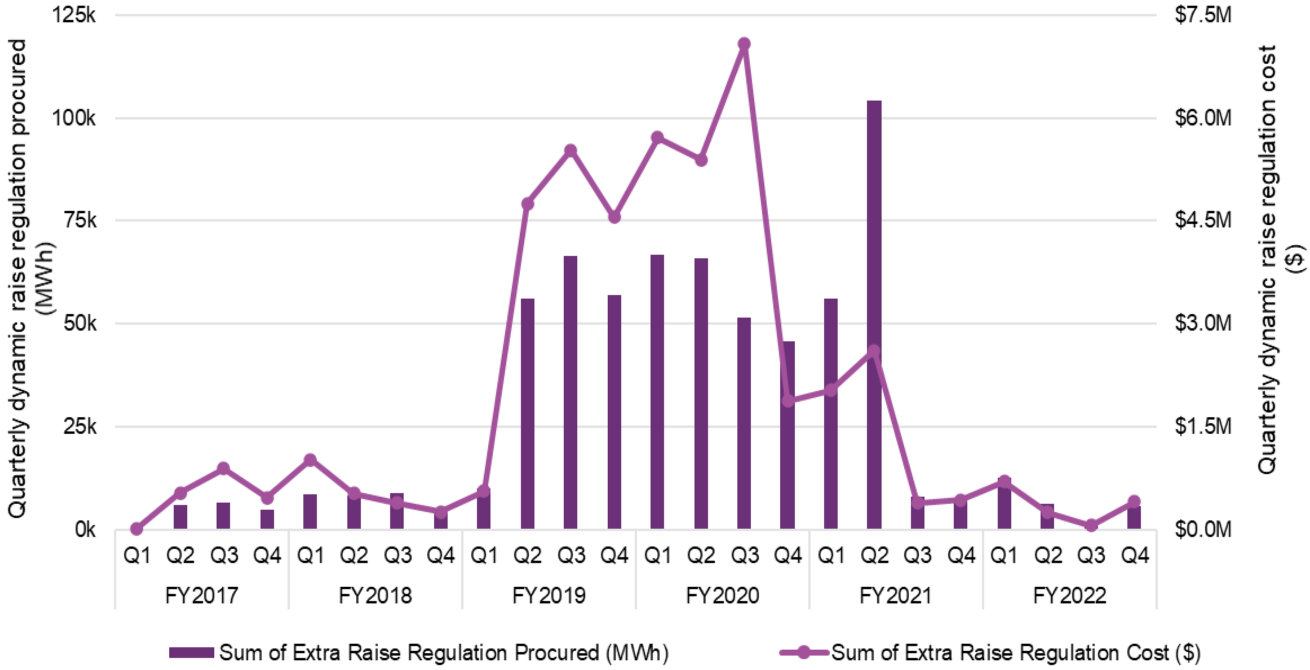


Figure 13 Quarterly dynamic raise regulation average procurement and average estimated cost per trading interval

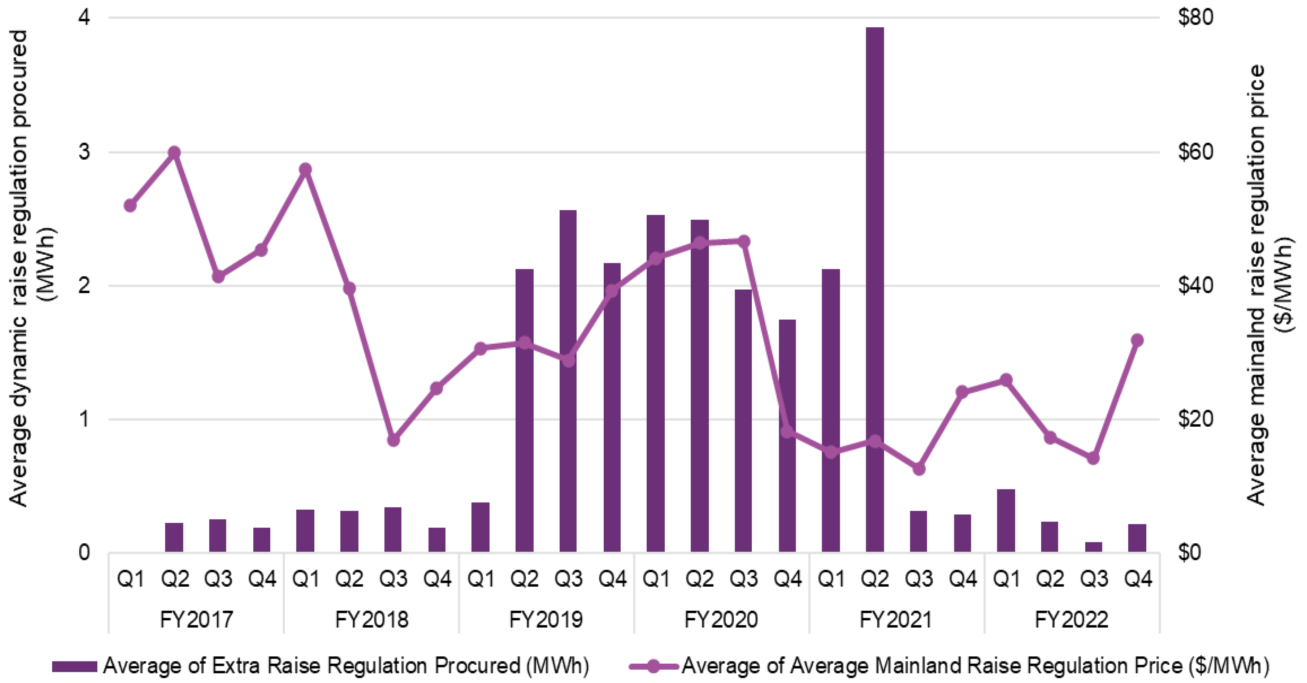


Figure 14 Quarterly dynamic lower regulation total procurement and total estimated cost

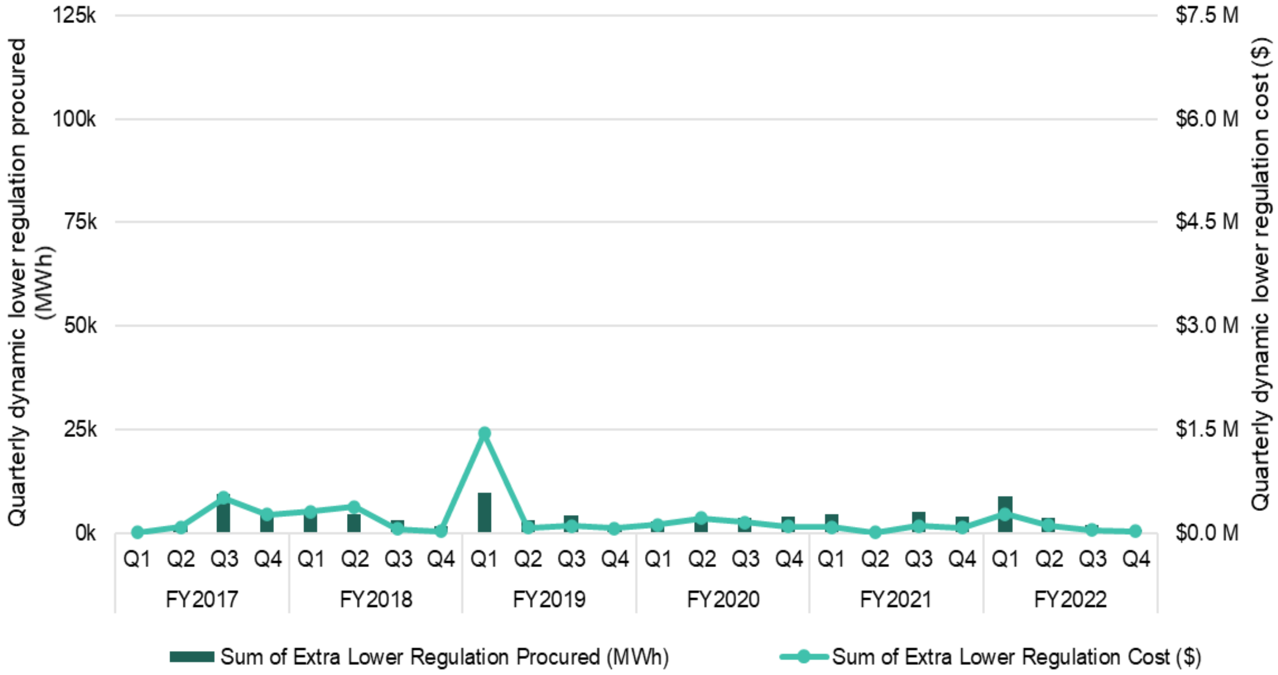
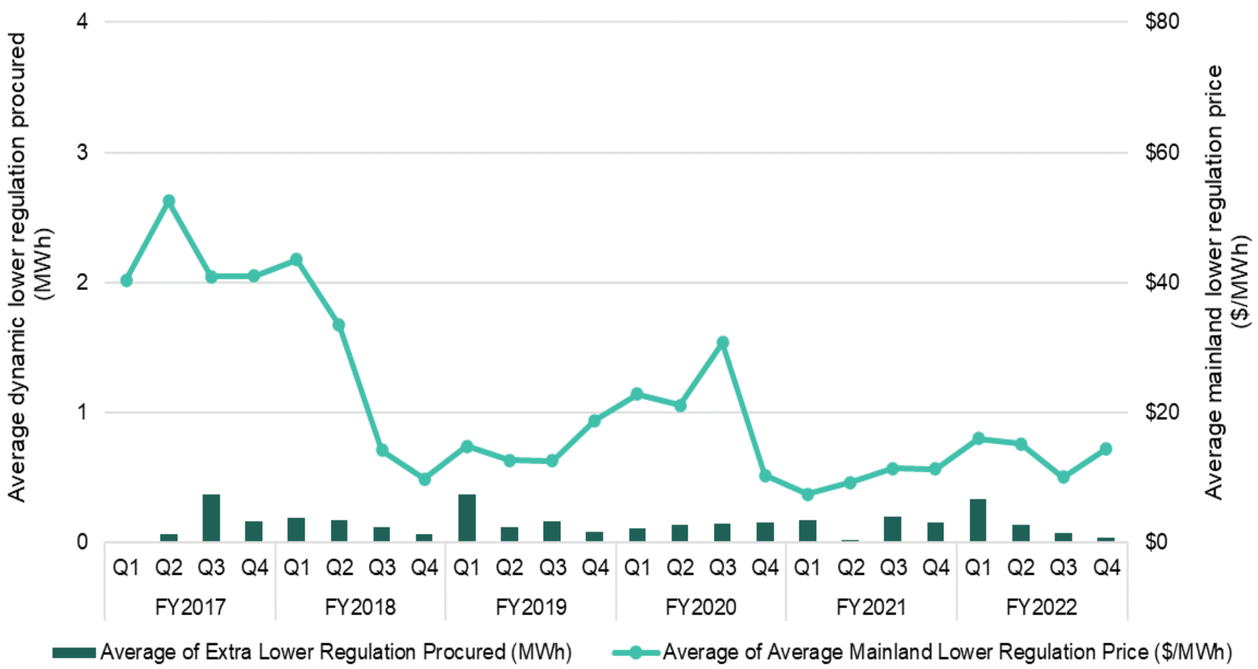


Figure 15 Quarterly dynamic lower regulation average procurement and average estimated cost per trading interval



5.3 Benefits and costs of retaining the time error standard

It may be considered that a time error standard provides an assurance that over the long term, the NEM maintains an average frequency of 50 Hz. The theoretical and practical planning and operation of the NEM has always assumed that frequency is 50 Hz on average. It is unclear what NEM processes may be inconvenienced by long-term under- or over-frequency bias in the NEM that could result from ceasing time error control, but candidates include forecasting, dispatch, utilisation of FCAS resources, causer pays, metering and settlements. AEMO notes that such processes are often inter-dependent and changes in one process can have downstream impacts that are difficult to predict and challenging to mitigate. For these reasons, it is likely that AEMO would maintain time error control mechanisms even in the absence of a FOS time error standard, to avoid the need to make wider system changes.

As outlined in the previous section, the costs of dynamic regulation procurement have been relatively low in most years compared to the overall cost of ancillary services (which in turn are only a small fraction of the energy market turnover) and the costs are expected to remain low if frequency performance continues at the levels observed in 2022. Furthermore, the administrative burden of managing time error in real time is generally considered to be minor.

AEMO views the option of maintaining a time error standard in the mainland as offering continuity in market operations while imposing minimal costs. AEMO discusses its advice as it applies to Tasmania in Section 5.6.

5.4 Technical implications of removing the time error standard

AEMO's advice to stage one of the 2017 FOS Review stated that AEMO considered that there were no system security (or reliability) implications specific to conducting time error correction. AEMO remains of this view. Since that review, no new evidence has emerged regarding such implications. If there remain some consumers dependent on an accurate grid time-keeping service in AEMO's view this would be better characterised as a power quality matter rather than a security or reliability matter. Note that AEMO has no evidence of any significant process that currently relies on grid-time or records of any complaints received regarding AEMO's time error management.

Without the mechanisms in place to control time error, it is plausible that raw accumulated time error could grow to quite large quantities. To prevent perverse outcomes, AEMO would be required to identify and update the systems and procedures that rely on time error measurements, such as in procurement of dynamic regulation and automatic offset of the target frequency in AGC. This undertaking is unlikely to be disruptive to NEM participants but would require a process of understanding any implications in full, obtaining the relevant technical resources required to implement the changes and monitor the outcomes. This work represents an opportunity cost when such scarce resources could be dedicated to questions that are more pressing in AEMO's view.

In summary, AEMO views the option of removing the time error standard as manageable in cost and impact, however AEMO wishes to be clear that regardless of the FOS, time error will still be monitored and controlled as necessary.

5.5 Consideration of an alternative mainland time error standard

AEMO does not consider there to be merit in evaluating the impact of different time error limits. For example, AEMO sees no reasons to suggest that a setting of ±10 seconds or ±30 seconds would make any material difference. AEMO's view is that if a FOS setting is required, the current setting of ±15 seconds appears to be reasonable, and not onerous to manage. A reasonable alternative rather than a different value, would be to not have a time error standard in the FOS, leaving AEMO to monitor time error and correct as necessary.

5.6 Time error management in Tasmania

Time error, like frequency itself, is generally less controlled in Tasmania than in the mainland for a variety of reasons, including the smaller system size, the predominance of hydro generating facilities, large load facilities and the role of the Basslink frequency controller. The increasing role of significant variations in wind power production is also being observed to produce large changes in frequency and therefore time error.

In FY2022, AEMO observed 9.1 hours when accumulated Tasmanian time error remained outside the time error standard of -15 seconds. This period was notable for the extended operation of Basslink near its import limit (and thus providing only unidirectional frequency control) over several days in December 2021[24]. In these circumstances, AEMO's options to return time error to within the standard are limited when the accumulation is primarily due to outcomes of market dispatch. Typically, these tend to change and balance out over time, but in this case the biased situation remained in place for several days. In response, AEMO reset the time error to zero three times, in effect cancelling approximately 49 seconds of time error[25].

AEMO believes the current time error standard is unrealistic to always achieve in Tasmania, given the configuration of its system and the dominant role of the Basslink frequency controller. There are fewer systems costs incurred by excessive time error in Tasmania as time error is not used to procure dynamic regulation in Tasmania, and the contribution of Tasmania's AGC automatic time error offset to total NEM regulation usage is small.

5.7 Time error control in the absence of a FOS time error standard

AEMO believes it is important for the discussion of time error standards to clearly separate any *FOS obligations* to keep within a certain time error from any actions AEMO may *choose* to do in relation to time error. Suggesting AEMO's control actions and policies must depend on an explicit FOS obligation is an unhelpful conflation.

As an example of this, AEMO notes that some parties have expressed concern that if a time error obligation was removed, or relaxed significantly, this would lead to AEMO not procuring more than the base amount of regulation FCAS. This is not the case; there are many good reasons to have dynamic regulation procurement, including as a substitute for 5-minute contingency FCAS, regardless of the existence of a time error standard. In the absence of a time error standard, it may make sense to link dynamic procurement to a different metric, such as a moving average frequency, or average regulation usage, but the concept of dynamic procurement would remain. In fact, in this example of dynamic regulation procurement, it could be considered that removing the obligation could create more options.

Whether a formal time error obligation exists or not, there remains a strong case for retaining some form of dynamic regulation procurement, and therefore there is unlikely to be a significant cost saving associated with removing the formal obligation.

[24] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/frequency-and-time-error-reports/quarterly-reports/2021/frequency-and-time-error-monitoring-4th-quarter-2021.pdf?la=en.

[25] Note that AEMO is not understood to have reset time error in the mainland system, except for islanding of a region which requires a reset to initially configure the AGC in that region.

5.8 Interaction of time error management and primary frequency control

AEMO's view of the most appropriate time error standard should be regarded as quite separate to how time error correction within AEMO's AGC system is handled. Time error control may be considered one form of integral control, which is an important part of the AGC objective function. It is only loosely linked to the time error standard itself. For example, it is not clear that removal of the time error standard would necessarily mean that the time error correction component in the AGC objective function should be removed.

AGC's time error correction functions can adjust the target AGC frequency to values outside the PFR deadband of ±0.015 Hz. This may seem like it would cause AGC and PFR to conflict, but this is not the case. AGC doesn't set the actual frequency, though it's action can of course influence it. AGC's time error correction flows through to units providing regulation FCAS, raising or lowering their regulation target relative to their base NEMDE trajectory. These units then provide PFR action from that adjusted AGC regulation target. For example, if target AGC frequency is raised to correct a negative time error, to say 50.04 Hz, this may cause AGC to raise the request of a unit providing regulation, to deliver say +4 MW from its NEMDE trajectory. But this is delivered slowly over time, while PFR continues to react to actual frequency. Over time, as frequency fluctuates, the unit output would be higher than its base NEMDE trajectory and contribute to reducing the time error. Note that these behaviours are dependent on the AGC tuning parameters, which are not directly related to the FOS obligations.

5.9 AEMO's advice for time error standards in the FOS

AEMO advice considers the following conclusions:

- Time error is best prevented rather than corrected. Time error accumulation is less with better frequency control closer to 50 Hz.
- AEMO will continue to monitor and correct time error independent of the FOS. A form of obligation in the FOS maintains transparency to the market and consumers of time error and its accumulation.
- The analysis outlined in this document has led AEMO to the view that on balance, the current mainland time error obligations are not onerous, and no clearly superior approach is apparent.
- While removing the time error standard entirely would be unlikely to lead to any direct issues, the standard nonetheless represents a transparency to the market and consumers for ensuring that the total energy delivered into the grid aligns with expectation.
- Removing unnecessary obligations is prudent as it streamlines operating practices, however the cost and effort involved in managing time error in the mainland has been relatively low. Furthermore, there would be some effort involved in removing time error management from all processes and procedures and some risk of impacting other NEM processes.
- There would be little gained by optimising time error settings of the FOS.
- AEMO proposes setting out some guiding principles under which AEMO may choose to reset time error. Principles could include:
  - Where AEMO reasonably determines that the time error cannot be efficiently corrected.
  - When reconnecting islanded areas.
  - Where material errors in scheduling have resulted in a significant accumulation of time error.

AEMO's advice is that the Reliability Panel consider removing a time error limit from the FOS, recognising AEMO will still monitor and control time error as necessary.

AEMO is to be transparent and report to the market through the quarterly frequency reports when time error has been reset.

Table 17 AEMO's recommends removal of the time error limit in FOS Table A.2 for accumulated time error

Present requirement		Mainland	Tasmania
~~1~~	~~Accumulated Time Error Limit~~	~~<15 seconds, except for an island or during supply scarcity~~	~~<15 seconds, except for an island or following a multiple contingency event~~

Abbreviations

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator Limited
AGC	Automatic generation control system
BESS	Battery energy storage system
DNSP	Distribution network service provider
DPV	Distributed photovoltaics
FCAS	Frequency control ancillary service
FOS	Frequency operating standard
FFR	Fast frequency response
FY	Financial year
Hz	Hertz
IBR	Inverter-based resources
ISP	Integrated System Plan
MASS	Market Ancillary Service Specification
mHz	millihertz
ms	milliseconds
MW	Megawatt
NEM	National Electricity Market
NER	National Electricity Rules
NOFB	Normal operating frequency band
NOFEB	Normal operating frequency excursion band
NSP	Network service provider
OFGS	Over-frequency generation shedding
PFCB	Primary frequency control band
PFR	Primary frequency response
PV	Photovoltaics
RoCoF	Rate of change of frequency
SCADA	Supervisory control and data acquisition
TNSP	Transmission network service provider
UFLS	Under-frequency load shedding
VRE	Variable renewable energy