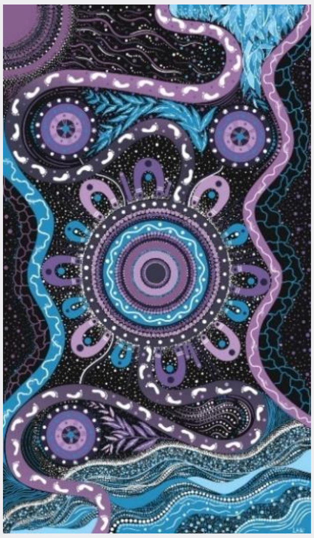
AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Technical Review of the NEM Frequency Control Landscape

July 2025

A report for the National Electricity Market



We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan.

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

The purpose of this publication is to review frequency control performance in the NEM as of July 2025 following implementation of recent NEM reforms and to provide technical insights regarding the frequency control landscape as the NEM transitions to future operational conditions. This report has been prepared as a priority action for FY2025 through AEMO's Engineering Roadmap program.

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Executive summary

Status of NEM frequency

This *Technical Review of the NEM Frequency Control Landscape* provides an overview of the National Electricity Market (NEM) system of frequency control and an assessment of its performance as of July 2025. AEMO considers that:

- The current frequency performance is satisfactory. Frequency is generally well-controlled during contingency events and during normal system operation.
- The existing NEM frequency control arrangements in place are proving sufficient for AEMO to procure the services required to meet its obligation to maintain power system frequency.
- Existing frequency control arrangements are proving to be adaptable as new technologies and risks emerge, as evidenced by AEMO observing operating periods where over 90% of frequency control ancillary services (FCAS) are supplied by non-synchronous resources.

Outlook for NEM frequency

The range of *Integrated System Plan* (ISP) pathways will create new potential challenges for maintaining frequency control but also new opportunities for emerging frequency control technologies. AEMO considers that:

- The required frequency control reserves will likely grow larger as the NEM transitions to more variable renewable energy (VRE) supply.
- The supply of frequency control resources will likely grow faster than the increasing reserve requirements due to the large-scale development of new sources of frequency control, such as utility-scale battery systems. However, there may need to be short-term temporary limits on frequency control capability of plants to ensure system security during this growth period.
- The relevance of system frequency as an indicator of energy supply and demand balance may decline due to increasing aggregate system frequency response capability.
- Maintaining satisfactory frequency performance may require further evolution of the existing NEM frequency control arrangements but AEMO considers that tuning within these existing arrangements will be sufficient to ensure the frequency control capabilities required in the NEM are always available.

What may need to change?

AEMO engages in a broad range of actions to maintain system security throughout the energy transition, outlined in further detail in the *Transition Plan for System Security*[1]. Through this Transition Plan, the Engineering Roadmap, and other secondary work programs, AEMO proposes the following list of priority actions and recommendations for further consideration to mitigate existing or emerging challenges concerning frequency control in the NEM power system.

[1] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/transition-planning/aemo-2024-transition-plan-for-system-security.pdf

Additional information on AEMO's broader outlook for frequency control in the NEM over various time-horizons will be included in the 2025 *Transition Plan for System Security*.

List of priority actions

- AEMO will complete the following actions after financial operation of the Frequency Performance Payments (FPP) reform begins:
  - Trial the implementation of basepoint adjustment in automatic generation control (AGC).
  - Review the use of regulation FCAS in correcting extended periods of under-frequency, including the role of time error in these calculations.
  - Review the interaction of primary frequency response (PFR) and AGC during the frequency response to contingency events.
  - Review the enablement volume of regulation FCAS reserves to determine the appropriate base quantity of regulation FCAS that should be enabled to correct dispatch errors.
  - Review the adequacy of current PFR settings for future system requirements.
- AEMO will work with relevant participants to make appropriate changes to address the observed power system oscillations in Tasmania.
- AEMO will complete a review of under-frequency load shedding (UFLS) in the NEM.
- AEMO will review the aggregate generator frequency response to ensure power system security can be maintained within network limits as inverter-based resources (IBR) with very fast frequency control are connected, and impose limits on frequency response if required.
- AEMO will develop a pathway to finalise the implementation of PFR on semi-scheduled units.
- AEMO will monitor and review:
  - The operation of FCAS control technology types.
  - The regional distribution of FCAS procurement.
  - The distribution of FCAS procurement amongst NEM units.
  - The evidence for the minimum droop setting implemented on IBR units.
  - The aggregate generator frequency response, and consider how this measure can be used in conjunction with system frequency as a control signal.

List of recommendations for further consideration

- The Reliability Panel should, at the next opportunity, consider providing frequency performance expectations during the failure of essential information technology (IT) systems, such as Supervisory Control and Data Acquisition (SCADA), Energy Market System (EMS), or Energy Market Management System (EMMS).
- The Reliability Panel should, at the next opportunity, consider whether the frequency operating standard (FOS) requirements in Tasmania are appropriate and achievable when Basslink is unable to provide frequency control.

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1 Status of NEM Frequency

The NEM operates with a range of frequency control arrangements in place that are delivering satisfactory and resilient frequency performance:

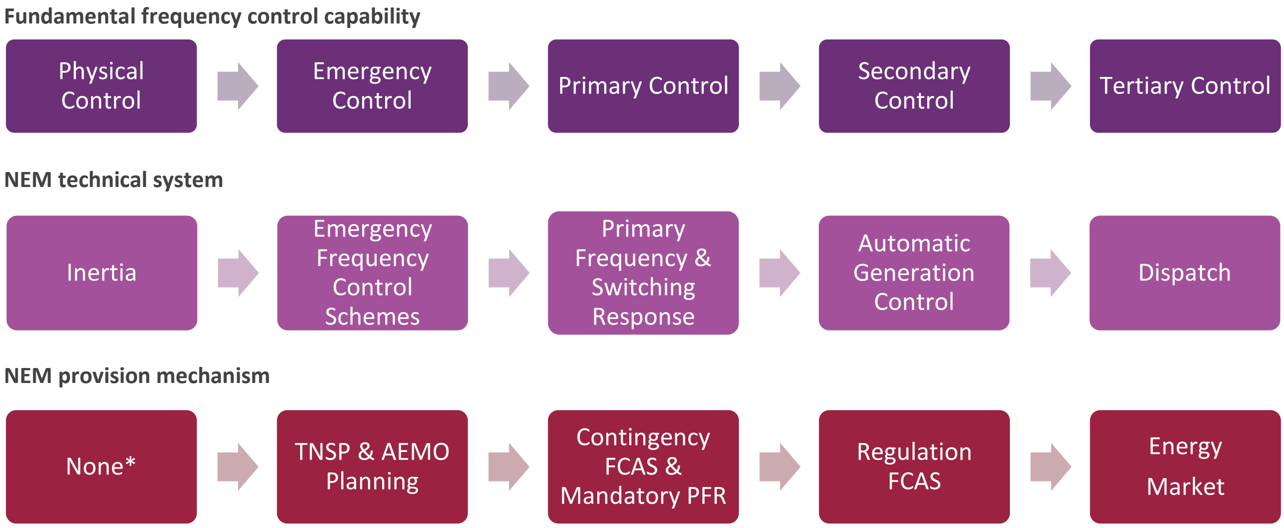
- Good frequency performance is a critical component of power system operation.
- Frequency control in the NEM is procured by competitive markets where practical.
- Ongoing performance will rely on maintaining and evolving these arrangements.

1.1 Introduction to the NEM system of frequency control

AEMO is responsible for frequency control in the NEM as required by clause 4.4.1 of the National Electricity Rules (NER). Satisfactory control of system frequency is a fundamental technical requirement to operate the NEM power system[2]. The energy balance of the NEM is maintained by the NEM system of frequency control, which is a system-of-systems working to return system frequency to 50 hertz (Hz). The Reliability Panel publishes the FOS to provide market expectations of system frequency performance during all power system circumstances[3].

Figure 1 shows the fundamental frequency control capabilities of an alternating current (AC) power system and the related technical systems and provision mechanisms for each capability that comprise the NEM system of frequency control.

Figure 1 The NEM system of frequency control



*Significant changes to inertia management in the NEM are likely from 2025 onwards following the implementation of the Improving Security Frameworks (ISF) for the Energy Transition rule change (see https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition) which requires AEMO to define a NEM-wide inertia floor and enable inertia services to maintain this level.

[2] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

[3] See https://www.aemc.gov.au/sites/default/files/2023-04/FOS%20-%20CLEAN.pdf.

1.2 Recent frequency performance

Frequency performance refers to the ability of the NEM power system to maintain a stable system frequency near 50 Hz, to contain system frequency following a contingency event and to recover system frequency back to 50 Hz in reasonable timeframes. The FOS provides detailed limits on acceptable frequency performance in the NEM. AEMO has reported NEM frequency performance against the FOS requirements since 2020 in accordance with NER 4.8.16, and these weekly and quarterly reports are available on AEMO's website[4]. The analysis presented here takes a long-term view of frequency control performance.

1.2.1 Evaluation of frequency performance

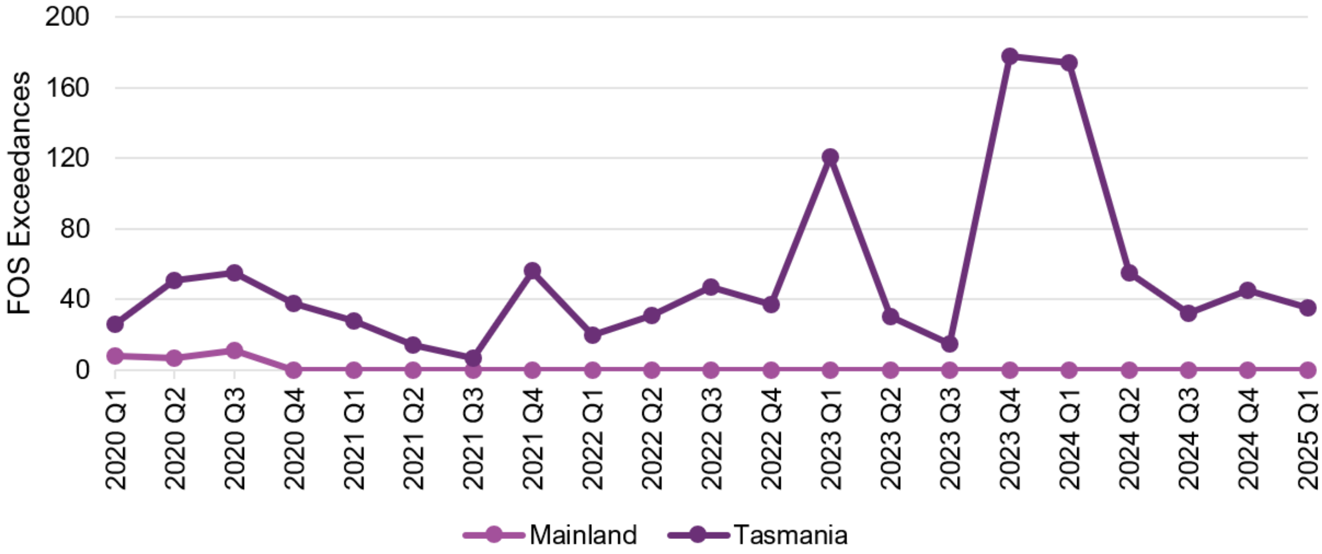
FOS performance

AEMO reviews cases where the FOS has not been met (FOS exceedances) to evaluate whether the NEM system of frequency control is meeting its performance expectations.

Figure 2 shows the number of quarterly FOS exceedances in the mainland and Tasmania since Q1 2020.

Insight: There have been no FOS exceedances in the mainland since Q3 2020, which aligns with the introduction of mandatory PFR in the NEM. However, Tasmania has experienced a much higher number of FOS exceedances since 2020, with evidence of a trend to higher numbers of exceedances in FY23 and FY24. A detailed discussion of the mandatory PFR reform is provided in Section 1.3, and of Tasmania's frequency performance and the underlying reasons for this trend in Section 1.2.1.

Figure 2 Quarterly FOS exceedances, 2020 to 2025



[4] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/frequency-and-time-deviation-monitoring.

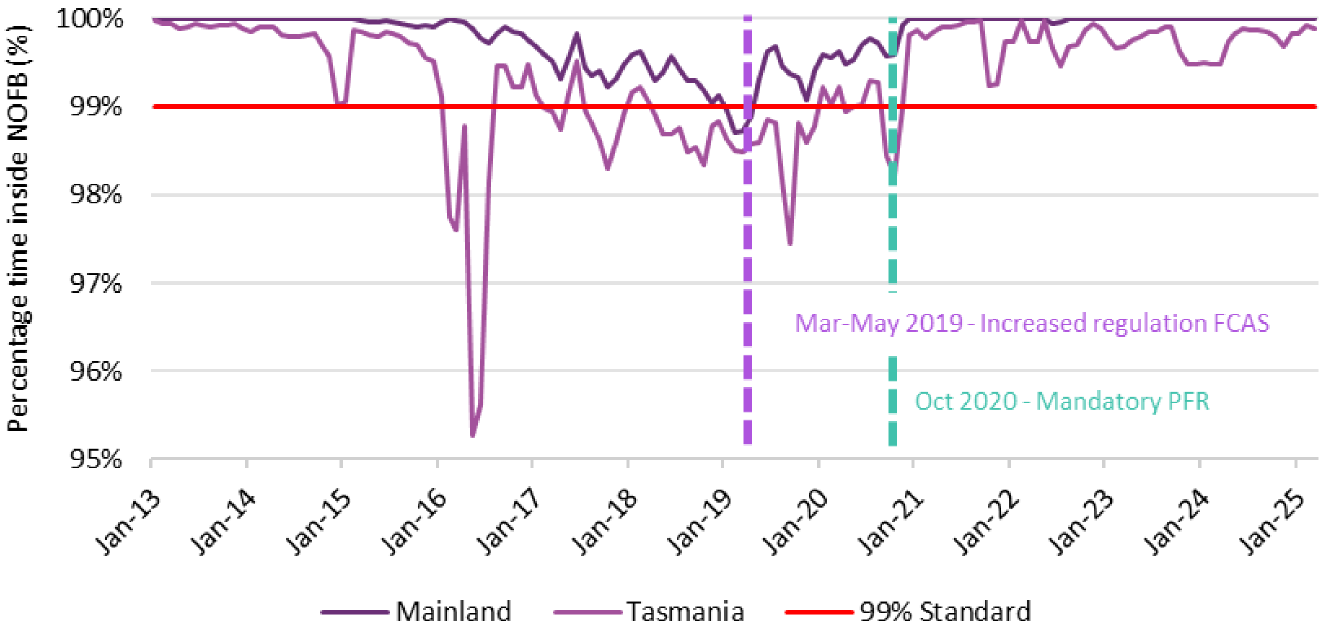
System operation without a contingency event

The ability of the NEM system of frequency control to maintain system frequency near 50 Hz when there is no contingency impacting the power system is a benchmark of frequency control performance. The FOS defines the *normal operating frequency band* (NOFB) of 49.85 Hz to 50.15 Hz as the range in which system frequency should remain 99% of the time when there is no contingency occurring.

Figure 3 shows the minimum daily percentage of time that system frequency remained inside the NOFB each month since 2013 after excluding periods of contingency as required by the FOS.

Insight: The NEM system of frequency control had satisfactory ability to remain within the NOFB for 99% of the time without a contingency each month until approximately 2016. From 2016 to 2020, a performance deterioration was evident, with some months not meeting the FOS. The time that system frequency remained within the NOFB improved from 2019 onwards due to corrective actions in frequency control arrangements, including procuring additional regulation FCAS in 2019 and the initial implementation of the mandatory PFR reform in 2020. Frequency in Tasmania was also outside this standard for many months between 2016 and 2020 but has returned to meeting this requirement of the FOS since late 2020.

Figure 3 Monthly minimum daily percentage of time frequency remained inside the NOFB, 2013 to 2025

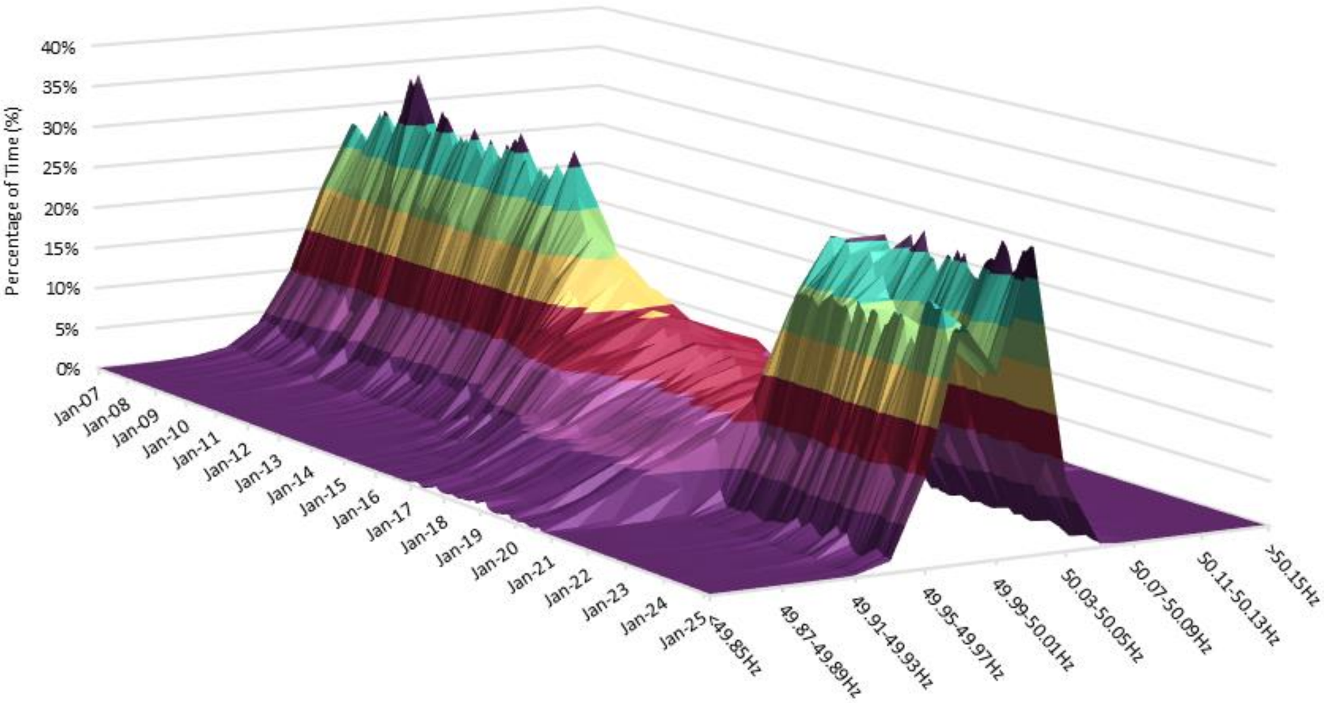


Further analysis of frequency performance inside the NOFB helps explain the observations in Figure 3.

Figure 4 shows the distribution of mainland frequency when inside the NOFB each month since 2007.

Insight: The period from 2016 to 2020 was characterised by system frequency being more widely spread from 50 Hz. Small changes in the supply demand balance could therefore cause NOFB excursions more often when system frequency spent more time closer to the NOFB edge, hence the greater number of NOFB excursions seen in Figure 3 over this period. Since the commencement of mandatory PFR from late 2020, system frequency has remained closer to 50 Hz and sits increasingly on the outside edge of the *primary frequency control band* (PFCB) of 49.985 Hz to 50.015 Hz.

Figure 4 Monthly frequency distribution, 2007 to 2025



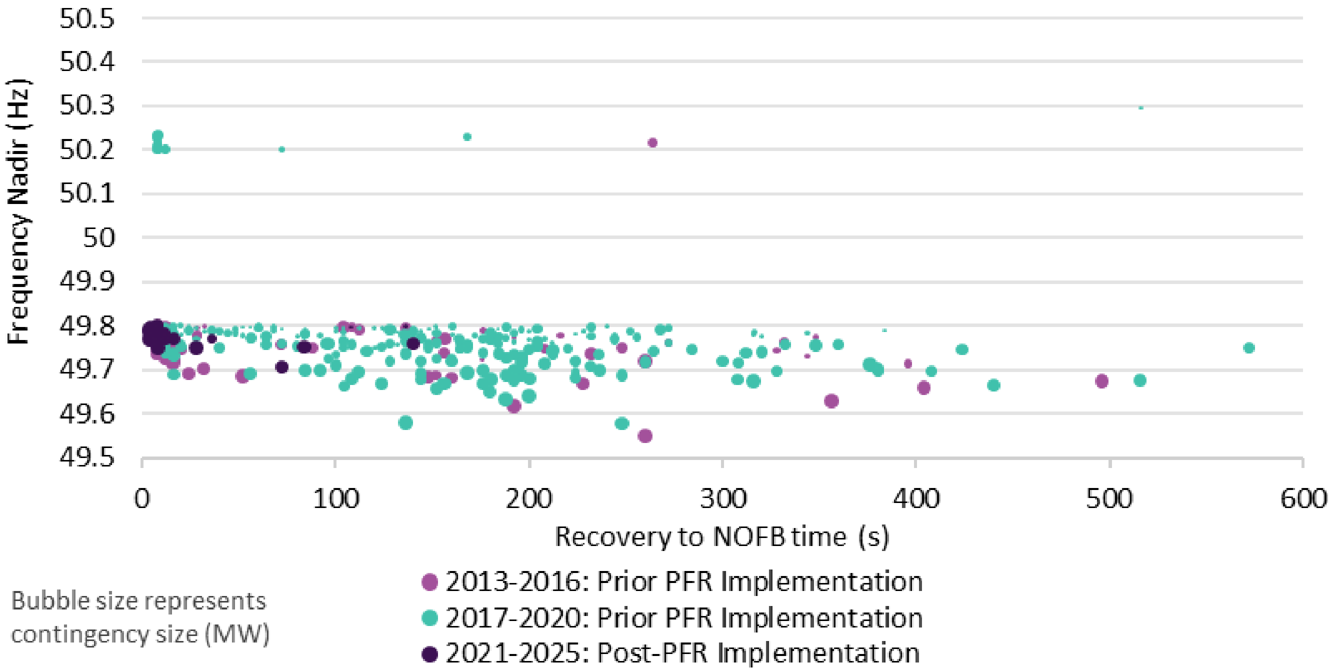
System operation during credible contingency events

The ability of the NEM system of frequency control to contain and recover system frequency in the immediate period following a contingency event is a further benchmark of frequency control performance. The FOS defines the frequency performance required in a credible contingency event.

Figure 5 shows the frequency outcomes of a number of credible generation and load contingencies in the mainland since 2013. In these cases, the required FOS containment band is the *generation and load change band* (GLCB) of 49.5 Hz to 50.5 Hz, and the required FOS recovery time is five minutes, or 300 seconds (s).

Insight: Since 2013 system frequency following credible continency events has been contained within the *generation and load change band,* and returned to within the NOFB in less than the required FOS recovery time following most credible contingency events. Following the implementation of mandatory PFR in late 2020, system frequency has always recovered to near 50 Hz within 300 seconds after credible contingency events.

Figure 5 Frequency outcomes of identified credible generation and load events in the mainland, 2013 to 2025



System operation during non-credible contingency events

Power systems experience a wide range of high impact contingencies which are difficult to anticipate and may occur at irregular intervals. NEM convention generally deems such events to be non-credible contingency events. The FOS defines the frequency containment band, frequency recovery time, and as of October 2023, the rate of change of frequency (RoCoF) limit applicable during a non-credible contingency event. These requirements are less restrictive than those for credible contingencies. The full set of requirements is in the FOS.

Table 1 summarises significant non-credible power system events and frequency outcomes since the start of the NEM.

Insight 1: The NEM power system has demonstrated a resilient ability to maintain system frequency during a wide range of high-impact non-credible contingencies. The NEM experienced five events since 2004 with sudden loss of greater than 1,900 megawatts (MW) in generation. In many of the cases shown in Table 1, UFLS was essential to retain control of system frequency and prevent system collapse.

Insight 2: The one instance of failure to control frequency occurred in South Australia in 2016 and resulted in a state-wide system blackout. This event highlights the importance of resilient frequency control capability in non-credible circumstances and has informed many subsequent frequency control reforms in the NEM.

Table 1 Significant non-credible power systems contingencies in the NEM

Date	Contingency event	System outcome	Estimated generation loss (MW)	Estimated load loss (inc UFLS) (MW)	Frequency nadir (Hz)
13 August 2004[A]	Explosion in Bayswater switchyard	Six large generators tripped	3,100 MW	1,500 MW (UFLS)	48.9 Hz

Date	Contingency event	System outcome	Estimated generation loss (MW)	Estimated load loss (inc UFLS) (MW)	Frequency nadir (Hz)
2 July 2009[B]	Explosion in Bayswater switchyard	Eight large generators tripped	3,205 MW	1,131 MW (UFLS)	49.00 Hz
19 June 2012[C]	Earthquake in La Trobe valley in Victoria	Five large generators tripped	1,955 MW	400 MW total 200 MW (UFLS)	49.20 Hz
28 September 2016[D]	Transmission faults and tower collapse in South Australia due to storm	Black system in South Australia	1,213 MW (all SA Generation)	1,826 MW (all SA demand)	Total system collapse in South Australia
3 March 2017[E]	Explosion in the Torrens Island switchyard	Five generators tripped	610 MW	400 MW (Other)	49.77 Hz
25 August 2018[F]	Lightning strike on QNI interconnector	Separation of Queensland and South Australia	None	997 MW – NSW/VIC (UFLS) 81 MW – TAS (UFLS)	48.95 Hz – NSW/VIC 50.46 Hz – SA 50.90 Hz – QLD
4 January 2020[G]	Bushfire in Snowy Mountains	Separation of New South Wales and Victoria	34 MW	43 MW	49.52 Hz – NSW 50.43 Hz – VIC
31 January 2020[H]	Transmission tower collapse in Victoria due to storm	Separation of South Australia	257 MW (OFGS)		49.66 Hz – NEM 51.11 Hz – SA
25 May 2021[I]	Explosion in Callide turbine hall	Nine large generators tripped and separation of Queensland	2,300 MW	1,308 MW (UFLS) 992 MW (Other)	48.53 Hz – QLD 49.68 Hz – NEM
12 November 2022[J]	Transmission tower collapse in South Australia due to storm	Separation of South Australia	None	None	50.53 Hz – SA
13 February 2024[K]	Transmission tower collapse in Victoria due to storm	Eight generators tripped	2,690 MW	1,000 MW (Other)	49.68 Hz

A. See https://www.aemc.gov.au/sites/default/files/content/5185b9e8-6c98-4078-bf5d-7391224e5be7/NEMMCO-Review-of-13-August-2004-Power-System-Incident.pdf.
B. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/psfrr/2018_power_system_frequency_risk_review.pdf?la=en.
C. See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2012/Victoria_Earthquake_19_June_2012_v3.pdf%20accessed%2027%20Mar%202017.
D. See https://www.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.
E. See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Report-SA-on-3-March-2017.pdf.
F. See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2018/qld---sa-separation-25-august-2018-incident-report.pdf.
G. See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-nsw-and-victoria-separation-event-4-jan-2020.pdf?la=en.
H. See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-vic-sa-separation-31-jan--2020.pdf?la=en.
I. See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/trip-of-multiple-generators-and-lines-in-qld-and-associated-under-frequency-load-shedding.pdf
J. See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/trip-of-south-east-tailem-bend-275-kv-lines-november-2022.pdf.
K. See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/preliminary-report---loss-of-moorabool---sydenham-500-kv-lines-on-13-feb-2024.pdf.

System operation during IT failure events

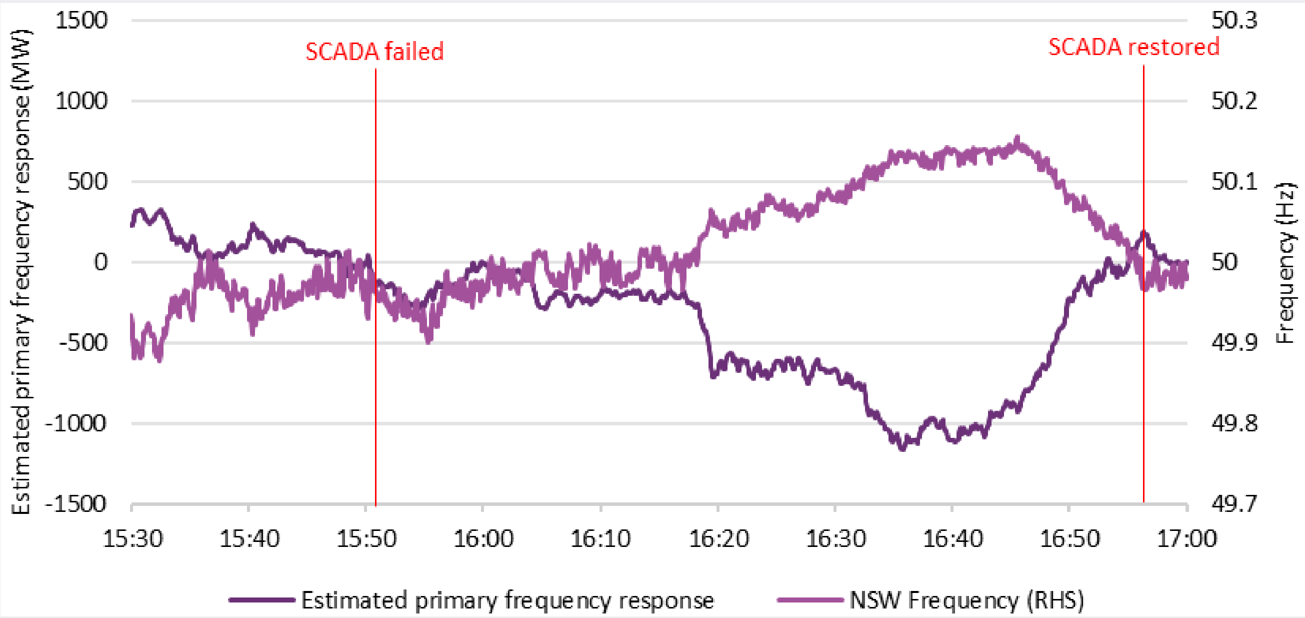
The non-credible events described above in Table 1 relate to contingency events affecting power system equipment, such as generating units and transmission lines in the NEM. AEMO has reported on the occurrence of multiple IT failures affecting SCADA systems in the NEM between 2021 and 2023[5] which can also impact the NEM system of frequency control. Systems responsible for energy dispatch and AGC were impacted as these rely on the continuous functioning of SCADA to provide their services.

Insight: The events of 24 January 2021 provide insight into the dependencies and resilience inherent in the NEM system of frequency control[6]. A chain of events, that began at 1344 hrs with a normal action by a control room operator, culminated at 1546 hrs with a total loss of function in the NEM SCADA system, including backup redundancy systems, for a period of 55 minutes. During this period, the automated NEM system of frequency control reverted to the following:

- Energy dispatch – large generating units were requested to disconnect from AGC and follow their targets manually. (Note that the energy targets provided by the NEM Dispatch Engine [NEMDE] during such an event grow inaccurate because NEMDE reverts to assuming generators met their previous target when SCADA is not available.)
- AGC – no AGC was used during this period.
- PFR – implementation of mandatory PFR in 2020 resulted in a large availability of local and autonomous frequency control which controlled system frequency until the NEM SCADA systems were restored.

Figure 6 shows the estimated PFR response and system frequency during this event.

Figure 6 Estimated primary frequency response during loss of SCADA incident on 24 January 2021



[5] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2023/multiple-incidents-impacting-nem-scada-between-2021-and-2023.pdf

[6] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/final-report-total-loss-of-nem-scada-data.pdf

Recommendation for further consideration

- The Reliability Panel should, at the next opportunity, consider providing frequency performance expectations during the failure of essential IT systems, such as SCADA, EMS, or EMMS.

  System frequency was maintained within the FOS for the duration of each event in the report referenced above, however AEMO considers that maintaining frequency within the current FOS may not be possible when essential IT systems are unavailable or degraded.

System operation in Tasmania

Frequency performance in Tasmania requires a separate assessment to frequency performance in the mainland owing to a number of unique Tasmanian characteristics, including:

- Being a separate AC synchronous island to the mainland.
- Systemic importance of Basslink high voltage direct current (HVDC) interconnector operation for frequency control.
- Large number of hydro generating units.
- Large load and generation contingency sizes relative to system demand.
- Low inertia at times of high IBR supply.

The FOS recognises these unique characteristics by providing separate frequency control requirements in Tasmania. Figure 2 earlier shows that Tasmania routinely sees more FOS exceedances than the mainland. AEMO's monitoring through its Quarterly Frequency Reports helps confirm that most of Tasmania's FOS exceedances occur when no contingency event has occurred in the Tasmanian system and Basslink is unable to provide frequency control. Specifically, there is a history of frequency exceeding the *normal operating frequency excursion band* (NOFEB, 49.75 Hz to 50.25 Hz) for events that do not meet the criteria of a contingency event.

Basslink provides frequency control to the mainland and Tasmania using a frequency differential calculation. Basslink will adjust its DC flow in proportion to the frequency difference between the two islands, in the direction required to support the lower system frequency. The Basslink transfer capacity is approximately half the average system load in Tasmania, and therefore can provide a very large frequency support capability to Tasmania when operating within its limits.

System frequency in Tasmania can be excellent and move in tandem with the mainland when Basslink is in service and its frequency controller is operating to maintain system frequency in both regions. Tasmanian frequency performance can be characterised into the following scenarios:

- When Basslink is in service and operating with headroom and footroom for frequency control.
- When Basslink is in service and operating at an export or import limit.
- When Basslink is out of service.

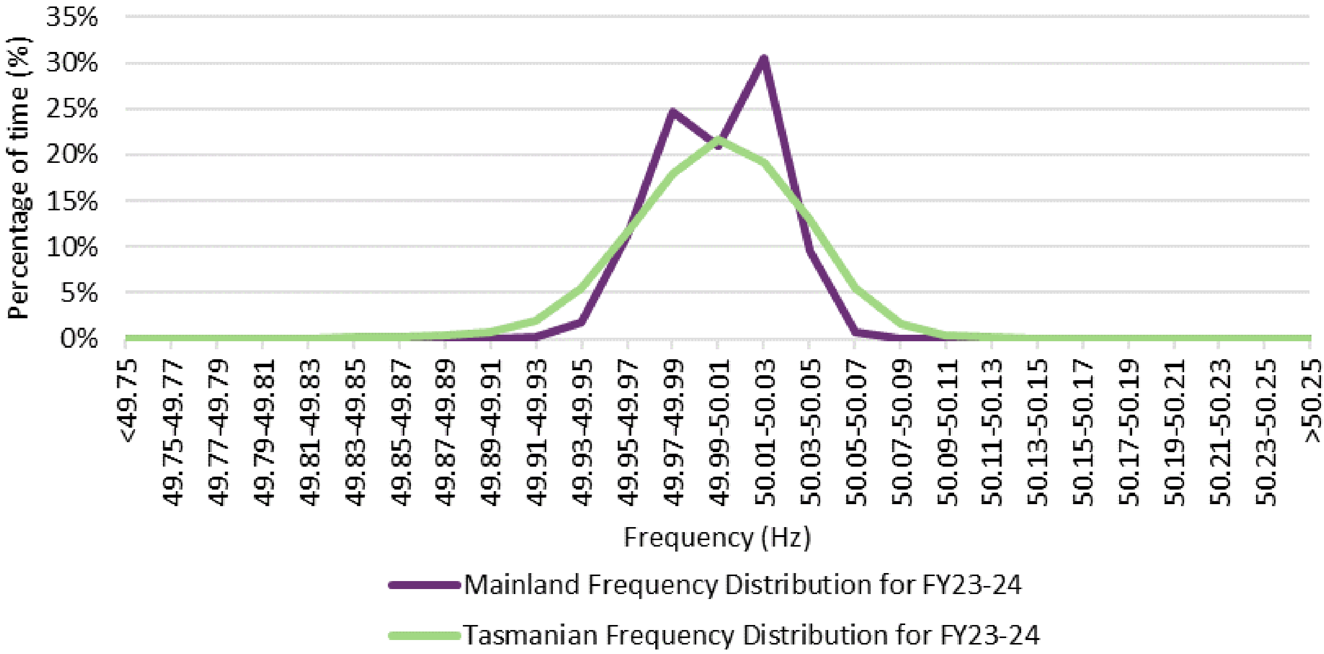
When Basslink is in service and operating with headroom and footroom for frequency control

AEMO estimates Tasmania operated with Basslink in service and with adequate headroom or footroom for frequency control approximately 94% of the time in FY2024. This scenario represents the most common system configuration of Tasmania.

Figure 7 shows the distribution of system frequency in Tasmania and the mainland in FY2024.

Insight: Tasmania's frequency performance around 50 Hz is comparable to but wider than the mainland when Basslink is in service. AEMO is satisfied with frequency performance during normal operation and contingencies during these intervals.

Figure 7 **Mainland and Tasmania frequency distribution for FY2024**



When Basslink is in service and operating at an export or import limit

Frequency performance in Tasmania can be impacted by the operation of Basslink at one of its export or import limits. These limits are full import limit, no-go zone import limit, no-go zone export limit and full export limit. Basslink does not have the same ability as an AC interconnector to sustain short-term flows above limits owing to its design as an HVDC link. This design prevents frequency control from being provided in one direction once a limit is reached, for example:

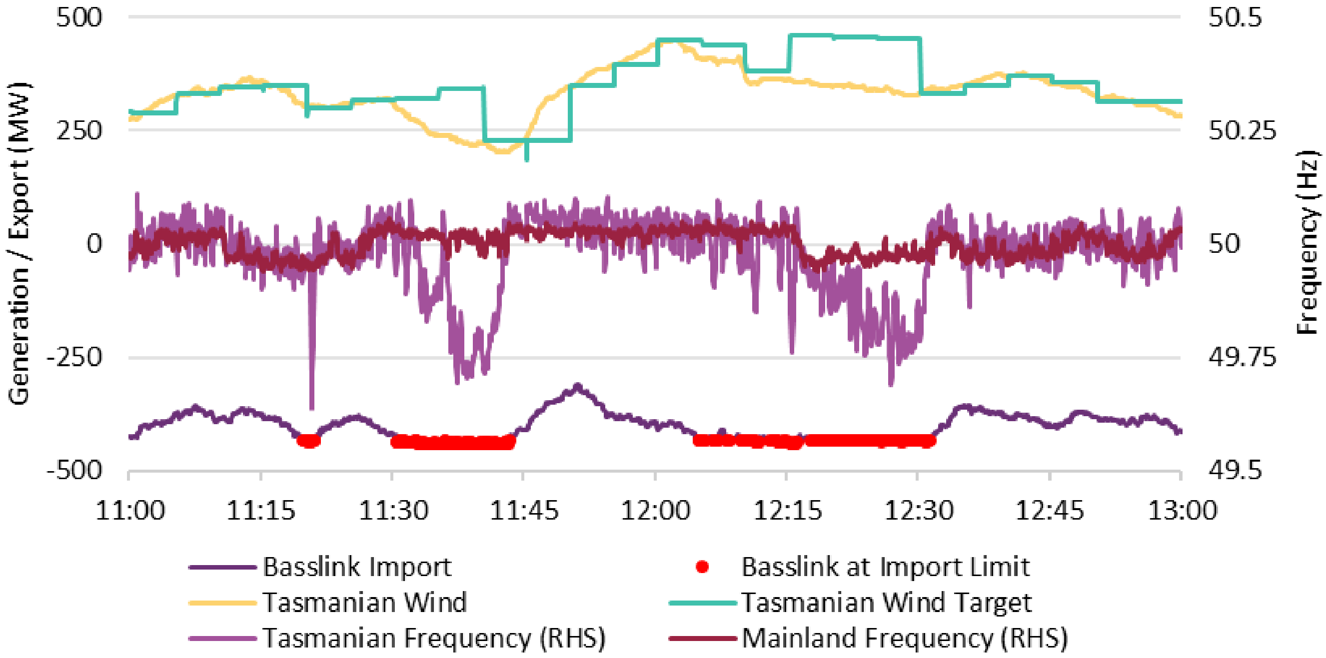
- Preventing further import to Tasmania at full import limit or no-go zone export limit.
- Preventing further export from Tasmania at full export limit or no-go zone import limit.

In practice, these scenarios manifest as 'one-sided' frequency control from Basslink, where frequency support is provided in one direction but not the other. AEMO estimates Basslink operated in a 'one-sided' frequency support role approximately 5% of the time in FY2024.

Figure 8 is an example of such a period where two frequency excursions outside the NOFEB occurred in Tasmania within two hours.

Insight: Under-delivery of energy compared to forecast from the aggregate of Tasmanian wind farms resulted in an energy deficit and a decline in Tasmanian frequency relative to the mainland frequency during these frequency events. Basslink was already near its import limit into Tasmania prior to each frequency excursion and Tasmanian frequency moved outside the NOFEB when Basslink was unable to provide further frequency support. In both cases, the situation was resolved by a reduction of the aggregate wind generation forecast and an increase in scheduled Tasmanian generation in the subsequent trading interval.

Figure 8 Example of Tasmanian frequency during one-sided Basslink period on 31 May 2024



When Basslink is out of service

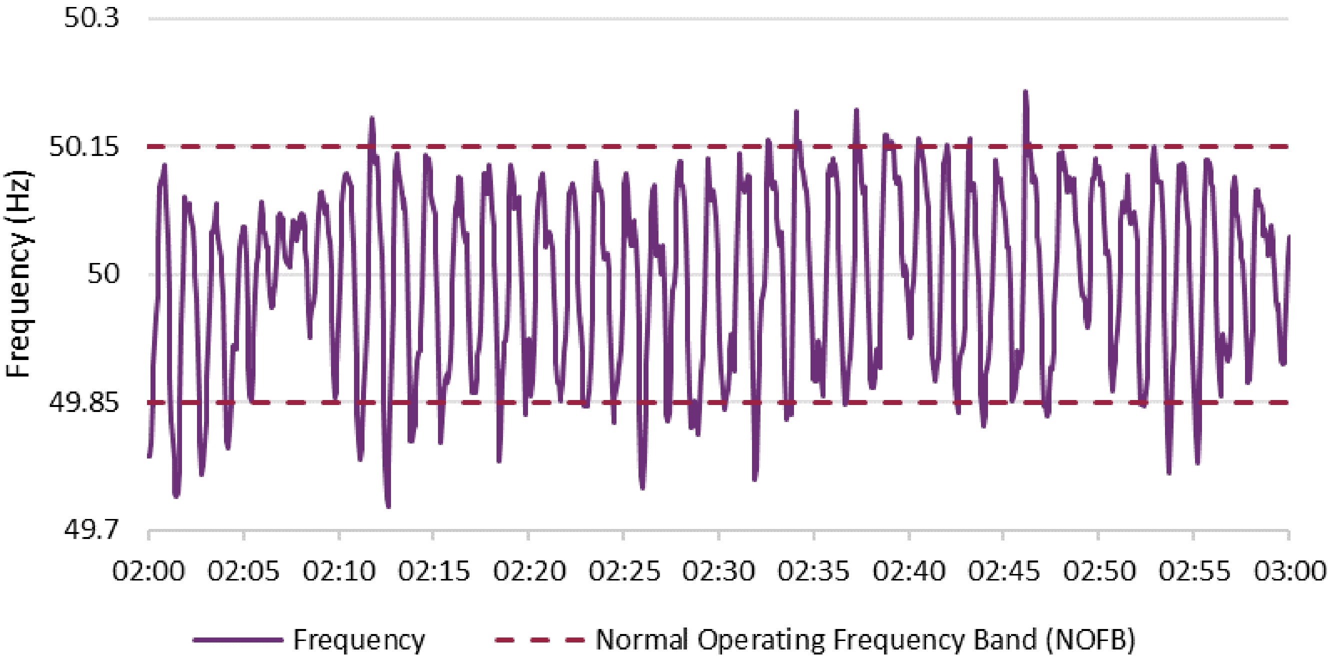
A natural test of Tasmania's local frequency control performance, and the importance of Basslink, is conducted whenever Basslink has an extended outage. In these circumstances Tasmania is required to source and deliver all frequency control from local units. AEMO estimates Basslink was not providing any frequency support approximately 1% of the time in FY2024, although notes Basslink was not necessarily on a declared outage during all these periods.

Figure 9 shows Tasmanian system frequency during a typical one-hour period of operation without Basslink.

Insight 1: Tasmanian system frequency can oscillate between approximately 49.75 Hz and 50.25 Hz when Basslink is out of service, with an oscillation period of approximately one minute. These oscillations can grow and diminish in magnitude but they are nearly always present in some form. Oscillations like these do not necessarily constitute a FOS exceedance as system frequency usually remains within the NOFB for greater than 99% of the time. However, they are unsatisfactory frequency performance owing to the clear indication that the frequency control mechanisms currently available in Tasmania could be tuned to work together better when Basslink is out of service. AEMO currently considers the interaction of PFR and AGC as being the likely source of these oscillations, due to the cycle in time approximately matching the control cycle time of AGC and the known delays in managing Tasmania's hydro generators via AGC.

Insight 2: AEMO has been observing these oscillations for some time and continues to be challenged to resolve them. They do not occur when Basslink is in service so there are limited windows for monitoring, testing and evaluation. These brief periods when Basslink is out of service can constitute a significant number of the total number of FOS exceedances in Tasmania, usually on account of exceeding the NOFEB of 49.75 Hz to 50.25 Hz without a contingency.

Figure 9 Example of Tasmanian frequency during Basslink outage period on 31 October 2023



Priority action

- AEMO will work with relevant participants to make appropriate changes to address the observed power system oscillations in Tasmania.

  AEMO considers it important to establish and resolve the underlying cause of these frequency oscillations to minimise any risks to the Tasmanian power system.

Recommendation for further consideration

- The Reliability Panel should, at the next opportunity, consider whether the FOS requirements in Tasmania are appropriate and achievable when Basslink is unable to provide frequency control.

  The unique characteristics of Tasmania's power systems warrant further consideration as to whether Tasmania should have the same FOS standards as the mainland when no contingency is occurring.

The experience of operating Tasmania is providing a wealth of knowledge about operating power systems at high percentages of IBR supply. Tasmania has experienced intervals where over 90% of its electrical load is supplied from non-synchronous sources. It is likely that the challenges faced in Tasmania will become more apparent in the mainland as the mainland NEM power system transitions to higher levels of instantaneous IBR supply.

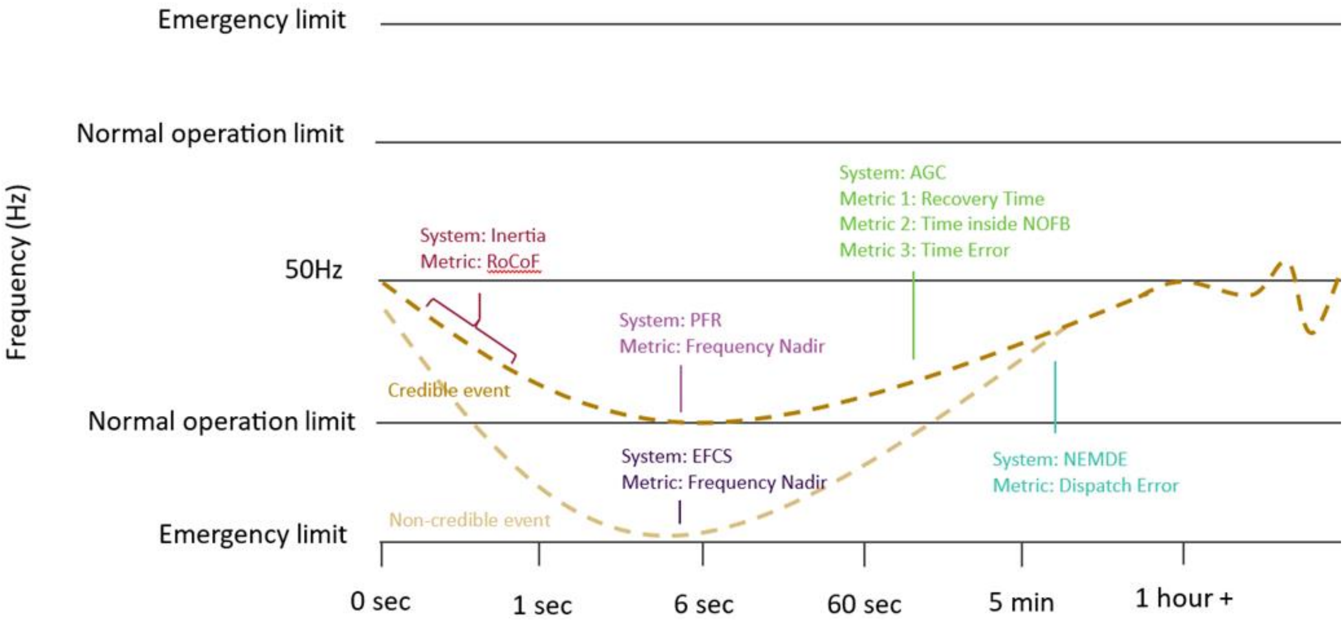
1.2.2 Evaluation of frequency control systems

Performance metrics of frequency control systems

Good frequency performance results from the effective configuration of the frequency control systems that together form the NEM system of frequency control. Each system described earlier in Figure 1 can be considered to have a specific role within the overall goal of maintaining a stable and controlled system frequency.

Figure 10 identifies each frequency control system, its period of greatest relevance during frequency control operations, and key performance metrics used by AEMO to assess its adequacy with respect to frequency control. A detailed examination of each system is provided further below.

Figure 10 NEM system of frequency control performance metrics



Inertia performance

Inertia is fundamental to effective frequency control because inertia slows the rate of change of frequency. Total system inertia is difficult to measure directly but can be estimated from the known inertia constants of generating units online at any one time. Alternative techniques for real-time inertia measurement are being trialled by AEMO and industry[7].

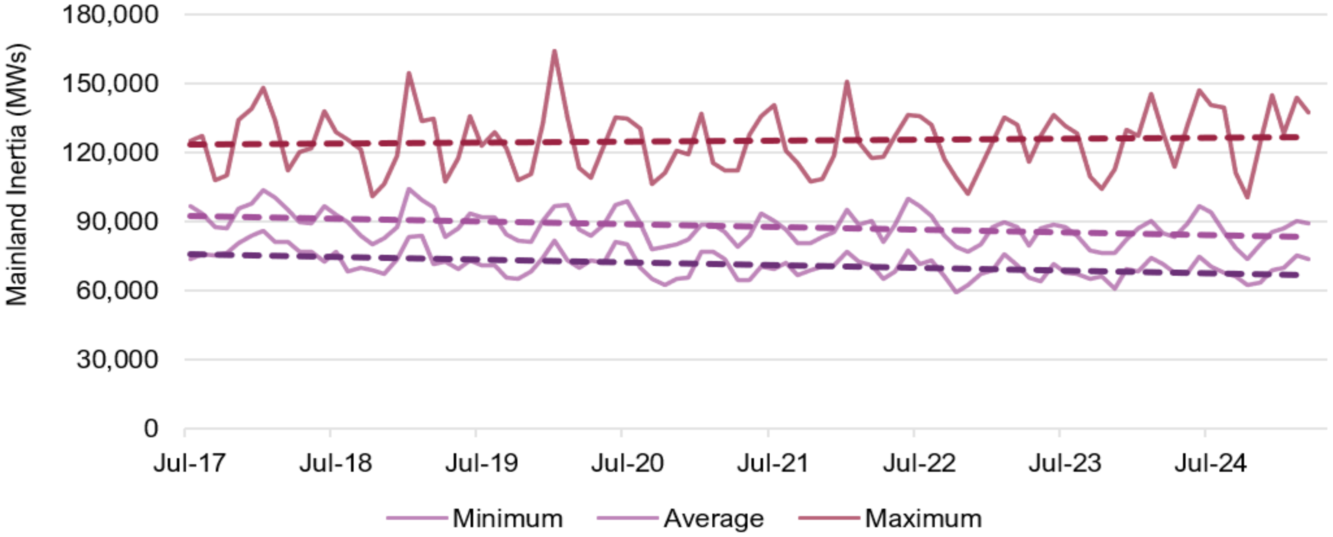
Figure 11 displays estimated monthly minimum, average and maximum inertia in the mainland region since 2017.

Insight: Inertia is declining in the NEM due to the substitution of synchronous generating units with non-synchronous generating units and permanent closure of large synchronous units. Average inertia declined from 93,000 megawatt seconds (MWs) to 84,000 MWs between 2017 and 2025. Minimum observed inertia declined from 73,700 MWs in 2017 to 59,500 MWs in 2022. A strong seasonal pattern is evident, with inertia at lowest levels around October and November each year, which corresponds with high VRE production, low system demand and maintenance of large synchronous units prior to summer. Maximum observed inertia remained high between 2017 and 2025.

[7] See https://aemo.com.au/initiatives/trials-and-initiatives/victorian-inertia-measurement-trial.

Several reforms are currently in implementation to address declining inertia. The Improving Security Frameworks for the Energy Transition rule change requires AEMO to formulate a minimum operating threshold for NEM-wide inertia and to consider the interchangeability of synchronous inertia, synthetic inertia and fast frequency response procured via Very Fast contingency FCAS. Transmission network service providers (TNSPs) in their role as Inertia Service Providers will need to contract inertia services to provide their portion of the NEM-wide inertia level in their region. See Section 1.3.3 for further information.

Figure 11 Monthly minimum, average and maximum mainland inertia, 2017 to 2025



Inertia determines initial RoCoF immediately following contingency events. AEMO reports quarterly on the maximum RoCoF observed in the mainland each month.

Figure 12 shows monthly maximum mainland RoCoF observed since 2020 when regular reporting commenced.

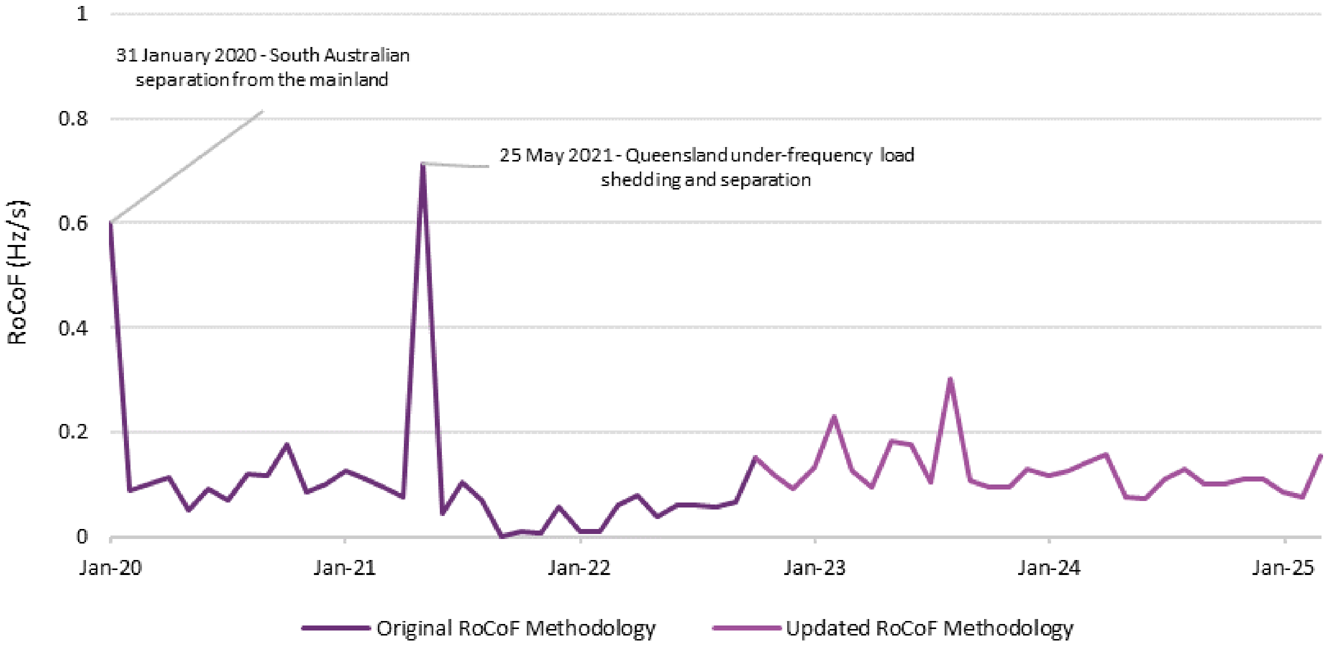
Insight 1: RoCoF has remained stable near 0.1 hertz per second (Hz/s) during the largest credible contingency events between 2020 and 2025. It is likely that the implementation of mandatory PFR from October 2020 has helped maintain RoCoF at that level while underlying inertia has decreased. There is some evidence of a trend to higher RoCoF values from 2023, however AEMO cautions this may be due to the implementation of a more accurate estimation methodology based on actual high-speed (20 millseconds [ms]) Phasor Measurement Unit (PMU) data over a rolling window of 500 ms rather than less granular samples (1-2 s) of the same data used prior to 2023.

Insight 2: RoCoF experienced during non-credible events can be significantly higher due to the potentially much larger instantaneous supply and demand imbalance. Separation of a region can amplify any RoCoF further due to the sudden loss of the stabilising AC connection with the NEM and the requirement to source all subsequent frequency control from within the separated island. Separation events occurred in South Australia and Queensland during both instances reported in Figure 12 when RoCoF exceeded 0.5 Hz/s.

Note that:

- The full methodology for calculation, including updates made in October 2022, is available in AEMO's latest Quarterly Frequency Report[8].
- RoCoF as reported in Figure 12 for January 2020 was measured in South Australia and in Queensland for May 2021.

Figure 12 Monthly maximum mainland RoCoF, 2020 to 2025



Emergency frequency control scheme performance

Emergency frequency control schemes (EFCSs) operate in rapid timeframes to correct large and sudden imbalances between supply and demand in the NEM power system. NER 4.3.1(k) and 4.3.5(a) require that AEMO and industry ensure that significant non-credible events affecting up to 60% of the total power system load can be mitigated using UFLS within the FOS requirements for a non-credible event. AEMO also oversees the operation of regional over-frequency generation schemes (OFGSs) to mitigate system risk during periods when system frequency remains well above 50 Hz, which could otherwise lead to an uncontrolled sequence of generation tripping.

Major non-credible contingency events that trigger operation of EFCSs are rare by nature and have occurred irregularly in the regions of the NEM over time. Table 1 earlier provides an overview of significant NEM non-credible contingencies and whether UFLS was triggered to restore system frequency. AEMO assesses the performance of EFCSs both in the absence of any EFCS activation and with standard incident review protocols following any EFCS activations. A number of publications are available on AEMO's website relating to recent reviews and updates to existing and future UFLS[9] and OFGS[10] systems.

Table 2 shows NEM power system outcomes during significant EFCS events identified in Table 1 since 2004. This summary of EFCS performance during these power system events provides insight into the long-term performance of EFCSs in the NEM.

[8] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/frequency-and-time-error-reports/quarterly-reports/2025/frequency-monitoring-q1-2025.pdf?la=en.

[9] See https://wa.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/managing-distributed-energy-resources-in-operations/adapting-and-managing-under-frequency-load-shedding-at-times-of-low-demand.

[10] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review.

Insight: Significant non-credible contingency events in the NEM power system have necessitated and validated the operation of EFCSs. The power system outcomes experienced during these events provide confidence that EFCSs in the NEM are performing well for their intended purpose.

The interconnected NEM system, or the relevant island within it, remained intact and operable in all cases but one. Frequency nadirs experienced remain well inside the 47-52 Hz thresholds required by the FOS.

The exception to this satisfactory performance occurred in South Australia on 28 September 2016. The power system collapsed in a black system event due in part to the inability of UFLS to operate fast enough for the circumstances of high RoCoF, which was measured at approximately 6 Hz/s[11]. AEMO and industry have implemented a number of recommended actions to minimise the possibility of such an event recurring.

There is a need to continue evaluating and anticipating the likely effectiveness of EFCSs as the underlying power system dynamics of the NEM change due to changing generation mix.

Priority action

- AEMO will complete a review of UFLS in the NEM.

  The importance and effectiveness of UFLS in the NEM is changing and AEMO must ensure the available schemes remain fit-for-purpose.

Table 2 System outcomes during EFCS events, 2002 to 2025

Date	Contingency event	System outcome	Estimated generation loss (MW)	Estimated UFLS loss (MW)	Frequency nadir (Hz)
13 August 2004	Explosion in Bayswater switchyard	Six large generators tripped	3,100 MW	1,500 MW	48.9 Hz
2 July 2009	Explosion in Bayswater switchyard	Eight large generators tripped	3,205 MW	1,131 MW	49.0 Hz
19 June 2012	Earthquake in La Trobe valley	Five large generators tripped	1,955 MW	200 MW	49.2 Hz
28 September 2016	Transmission faults and tower collapse in South Australia due to storm	Black system in South Australia	1,213 MW (all SA Generation)	1,826 MW (all SA demand)	Total system collapse in South Australia
25 August 2018	Lightning strike on QNI interconnector	Separation of Queensland and South Australia	None	997 MW – NSW/VIC	48.95 Hz – NSW/VIC
31 January 2020	Transmission tower collapse in Victoria due to storm	Separation of South Australia	257 MW (OFGS)	None	49.66 Hz – NEM 51.11 Hz – SA
25 May 2021	Explosion in Callide turbine hall	Nine large generators tripped separation of Queensland	2,300 MW	1,308 MW	48.53 Hz – QLD

[11] See https://www.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.

Primary frequency response performance and switched frequency control

PFR provides the first sustained frequency control action from market units following a change in system frequency. Sufficient system inertia will ensure enough time for PFR to engage and deliver its essential contribution to controlling system frequency until secondary control and market dispatch can rebalance supply and demand in the electricity system. The evidence of PFR contribution is seen in the frequency nadir reached during contingency events, as this value typically represents a moment in time where inertia no longer has any influence and secondary control has not yet begun to provide support.

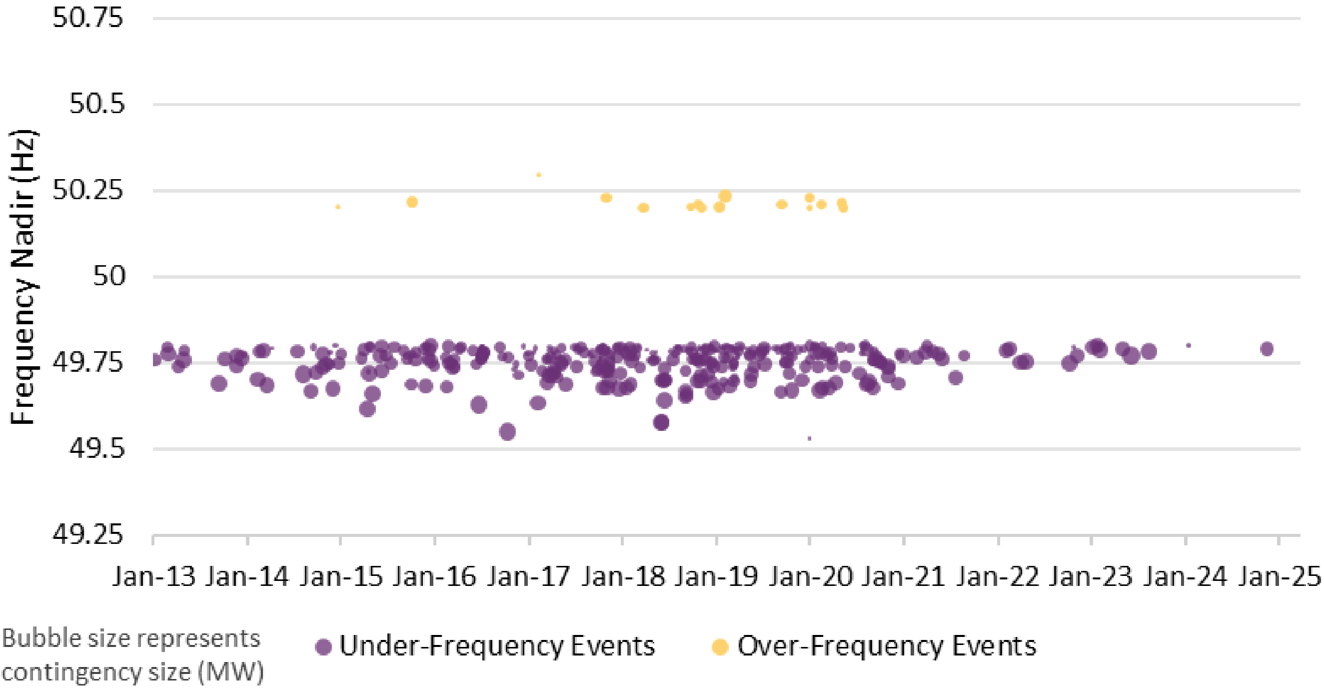
Switched frequency controllers enabled for Very Fast and Fast contingency FCAS, which provide frequency response when frequency exceeds a predefined trigger level, also provide early response to frequency events. To ensure adequate aggregate frequency response from switched controllers, trigger levels need to be prudently spread, and the proportion of switched control to primarily frequency control well maintained to a secure level.

AEMO uses the Very Fast, Fast, and Slow contingency FCAS markets to ensure sufficient primary frequency response and switch frequency control is available to manage power system security.

Figure 13 shows the frequency nadir of credible contingency events in the NEM since 2013.

Insight: Frequency nadir has been well-contained within the FOS requirement between 49.5 Hz and 50.5 Hz since 2013. The ability of the NEM to contain system frequency within this band following a sudden supply and demand imbalance is closely related to the availability of PFR. PFR availability had been declining for many years as evident in the widening of frequency nadirs visible in Figure 13 from approximately 2015 onwards. Rule changes mandating PFR saw this performance restored from 2020 onwards.

Figure 13 Frequency nadir by contingency size, 2013 to 2025



Automatic generation control performance

It is important to consider how the performance of AEMO's AGC system factors into overall NEM frequency behaviour. This is not a straightforward task, because AGC by necessity is tasked with managing several competing objectives simultaneously. The key objectives of the AGC system in the NEM are:

- Ramping scheduled units to their next energy market target every five minutes.
- Returning system frequency to 50 Hz.
- Returning time error to 0 seconds.

AGC is constrained in its ability to meet these objectives by the following:

- Limits on the quantity of regulation FCAS enabled.
- Limits on AGC unit ramp rates.
- Limits on which NEM units are visible to AGC.
- Communication and control delays between AGC and generating units.
- Variability of response from generating units on AGC to received AGC setpoints, including due to PFR.

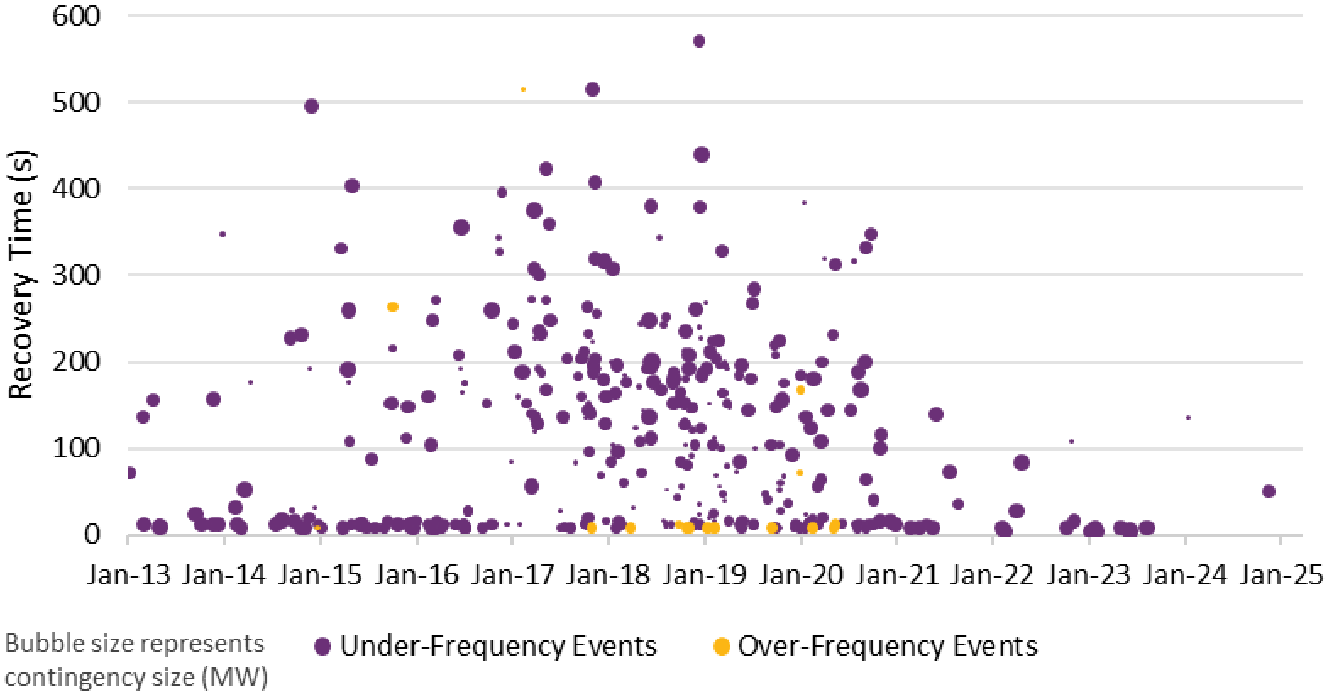
The time taken to recover system frequency following a credible contingency event is a key metric of AGC performance. AEMO uses the regulation FCAS markets to ensure sufficient AGC capability is available to manage power system security.

Figure 14 shows the frequency recovery time of credible contingency events in the NEM since 2013.

Insight 1: The frequency recovery time has remained within the FOS requirement of five minutes for a credible contingency event since 2021. There is evidence that performance against this metric is partly influenced by PFR due to the increase in average recovery times between 2015 and 2020, followed by a decrease following the implementation of mandatory PFR.

Insight 2: System frequency is now recovering to within the NOFB within 10 to 20 seconds for large credible contingency events due to abundant PFR, which is faster than AGC's typical control cycle, meaning AGC plays only a minor role in these shorter frequency deviations.

Figure 14 Frequency recovery time to the NOFB by contingency size, 2013 to 2025



Priority actions

- AEMO will complete the following actions after financial operation of the FPP reform begins:
  - Trial the implementation of basepoint adjustment in AGC.

    Basepoint adjustment in AGC is an additional calculation that can reduce deviations from energy target on generation units providing PFR, and transfer that generation to units providing regulation FCAS. AEMO considers it may offer a practical means to increase the role of regulation FCAS.
  - Review the use of regulation FCAS in correcting extended periods of under-frequency, including the role of time error in these calculations.

    AEMO considers the usage of regulation FCAS following contingencies could be more responsive to system requirements.
  - Review the interaction of PFR and AGC during the frequency response to contingency events.

    While the recent speed of frequency recoveries due to abundant PFR is desirable from a system perspective, there is further room to consider how PFR and AGC could be better used in combination, how AGC could be better tuned to control system frequency, and the adequacy of current PFR settings for future operational conditions.

Dispatch performance, with respect to frequency control

The NEMDE energy market dispatch calculation schedules generation supply to meet expected system demand at the end of each five-minute trading interval. Mismatches between forecast supply and forecast demand lead to frequency deviations that are corrected during the trading interval by the primary and secondary control systems discussed above.

These frequency control systems need to have sufficient reserves to correct the potential error that eventuates during the energy market dispatch.

Figure 15 and Figure 16 show the quarterly trend in average and maximum aggregate dispatch error since 2006 for semi-scheduled and scheduled units respectively, when their unit dispatch error was not assisting frequency to return to 50 Hz and their dispatch error was not due to tripping.

Insight 1: The underlying aggregate dispatch error of semi-scheduled units has been growing since 2007 in approximate parallel to the increasing connection and dispatch of VRE units. The average dispatch errors observed in FY2024 of approximately ±100 MW were partly due to the large number of VRE units which act to offset each other's individual dispatch errors and minimise the average error in aggregate. AEMO notes that the maximum dispatch errors observed in FY2024 were between approximately ±750 MW and ±1000 MW each quarter. Large dispatch errors typically occur on rare occasions when a number of VRE units have large coincident individual dispatch errors.

Insight 2: The underlying dispatch error of scheduled units has not increased since 2006, with some evidence of a trend towards decreasing quantities of underlying dispatch errors. The average dispatch errors observed in FY2024 are between approximately ±25 MW and ±75 MW. The maximum dispatch errors observed in FY2024 are between approximately ±250 MW and ±750 MW.

Insight 3: The base volume of procured regulation FCAS is 220 MW for Raise regulation FCAS and 210 MW for Lower regulation FCAS. These quantities appear to reflect a volume that is above the combined average dispatch error of the scheduled and semi-scheduled units in the NEM but well below the maximum observed dispatch error. It is likely mandatory PFR is providing significant support to system frequency during the trading intervals when large aggregate dispatch errors occur.

Note that this analysis:

- Removes any frequency correction provided by units providing primary control and secondary control frequency response which acts to mask the size of the underlying dispatch error.
- Removes tripped units, as these contingency events trigger a short-term response from contingency FCAS providers. Contingency FCAS is unlikely to be used when frequency remains within the NOFB as occurs when the NEM has a high aggregate dispatch error.

Figure 15 Quarterly average and maximum dispatch error of semi-scheduled units not assisting frequency, 2006 to 2025

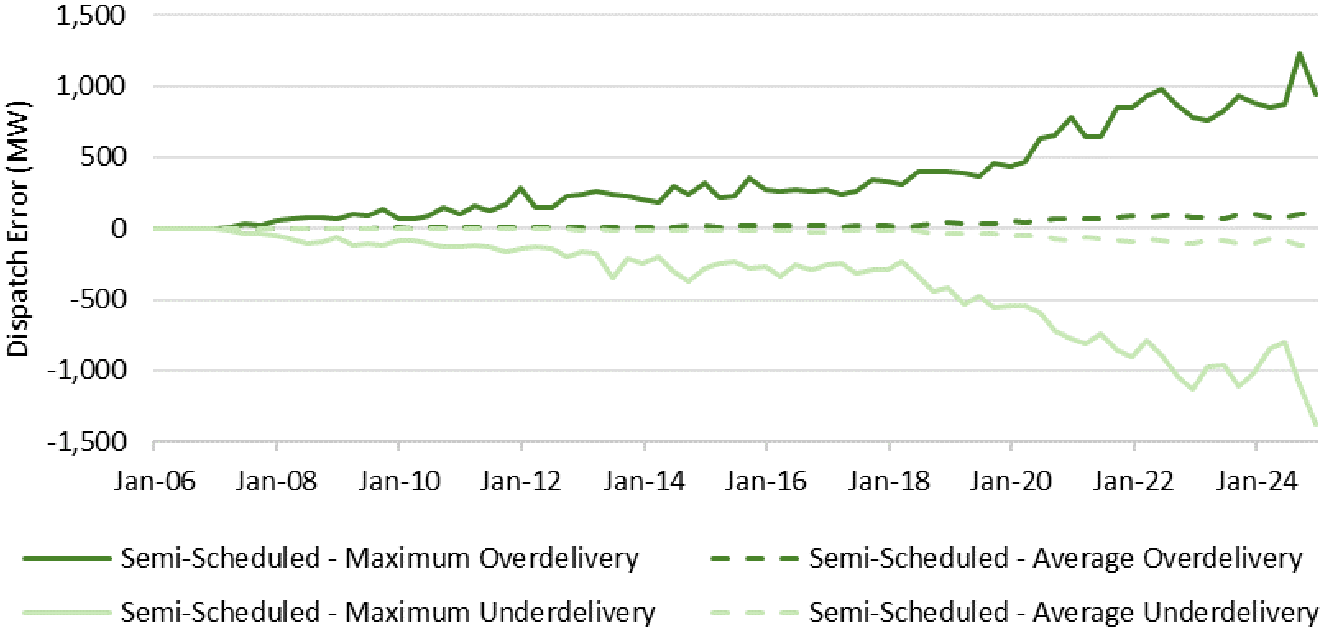
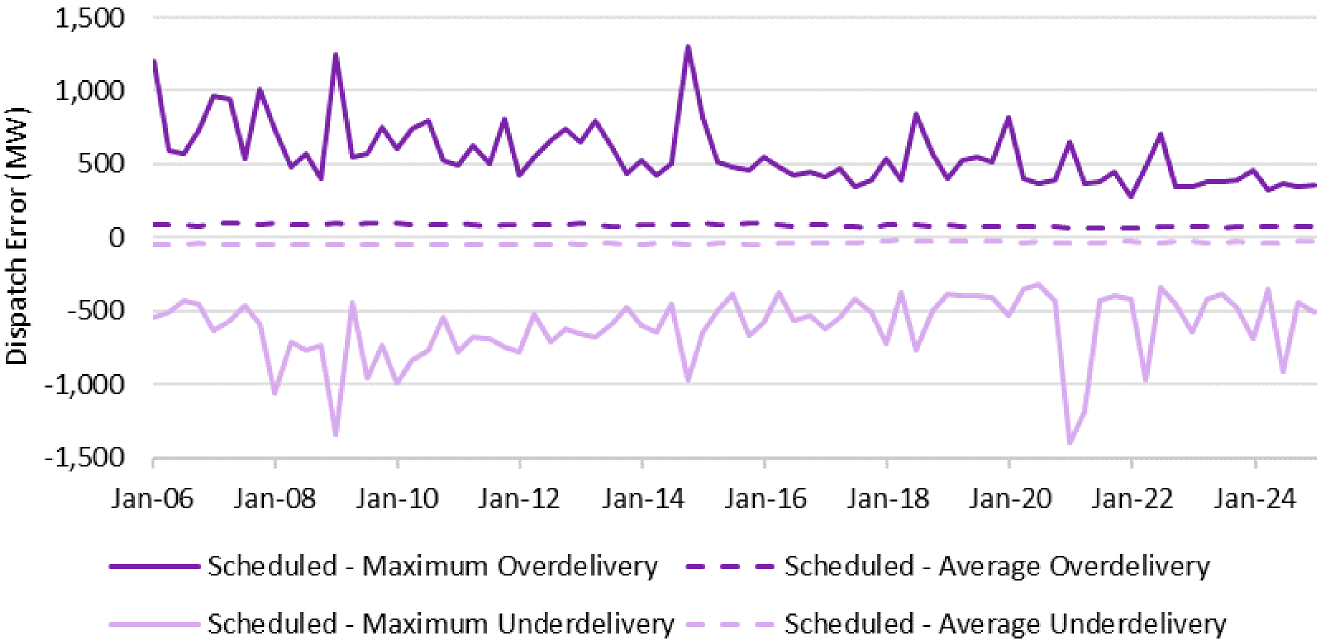


Figure 16 Quarterly average and maximum dispatch error of scheduled units not assisting frequency, 2006 to 2025



Priority action

- AEMO will complete the following action after financial operation of the FPP reform begins:
  - Review the enablement volume of regulation FCAS reserves to determine the appropriate base quantity of regulation FCAS that should be enabled to correct dispatch errors.

    AEMO considers the enabled volume of regulation FCAS could be more responsive to system requirements.

1.2.3 Evaluation of FCAS markets

Ancillary services in the NEM support the energy dispatch market. FCAS markets are co-optimised every trading interval with the energy market. AEMO sets the required volume of each FCAS market every trading interval based on power system conditions. The price of each FCAS market is then determined by the marginal FCAS offer which supplies the last incremental 1 MW of FCAS requirement. Factors that impact the cost of FCAS include:

- FCAS requirements.
- FCAS availability.
- Energy prices, since FCAS prices are linked to energy prices.

FCAS cost recovery is subject to a range of processes. Raise contingency FCAS is recovered from Cost Recovery Market Participants (CRMPs) with adjusted sent out energy (ASOE) values. Lower contingency FCAS is recovered from CRMPs with adjusted consumed energy (ACE) values. Regulation FCAS is recovered through the Frequency Performance Payments process[12].

FCAS requirements

AEMO determines a required volume of each FCAS market for each trading interval. FCAS procurement is co-optimised with energy dispatch in NEMDE to minimise the overall cost of procuring all required services. Details on how each FCAS requirement is determined are provided in the Quarterly Frequency Report[13].

Figure 17 shows the quarterly average trading interval volume requirement of each FCAS market since the start of the FCAS markets (Lower FCAS volumes are provided on the negative axis).

Insight 1: Average FCAS requirements have increased since the start of the FCAS markets. Factors for this increase include:

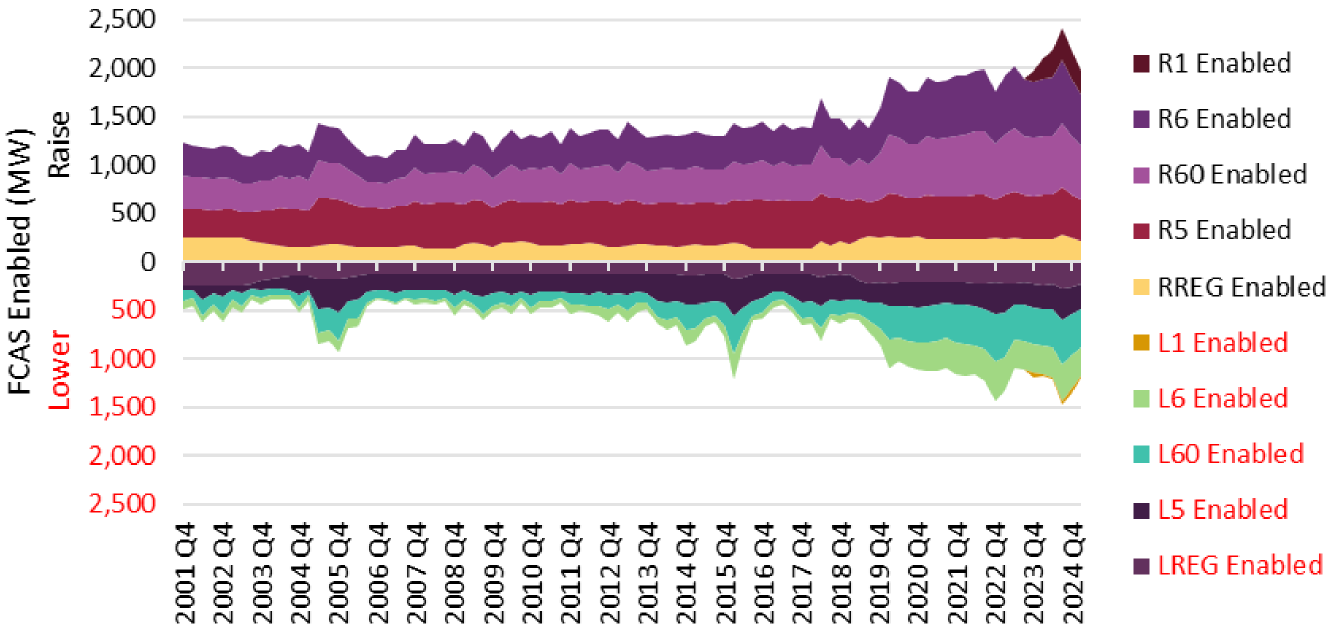
- Increasing size of largest credible risk.
- Decreasing assumed system load relief due to less frequency-sensitive load.
- Increases to regulation FCAS volumes.
- Addition of two new FCAS markets in 2023.

[12] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/frequency-contribution-factors.

[13] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/frequency-and-time-error-reports/quarterly-reports/2025/frequency-monitoring-q1-2025.pdf?la=en.

Insight 2: Raise FCAS requirements have consistently been larger than Lower FCAS requirements due to the ongoing larger size of typical largest credible generator risks when compared to the typical largest credible load risks.

Figure 17 Quarterly average FCAS market requirements, stacked, 2001 to 2025



FCAS availability

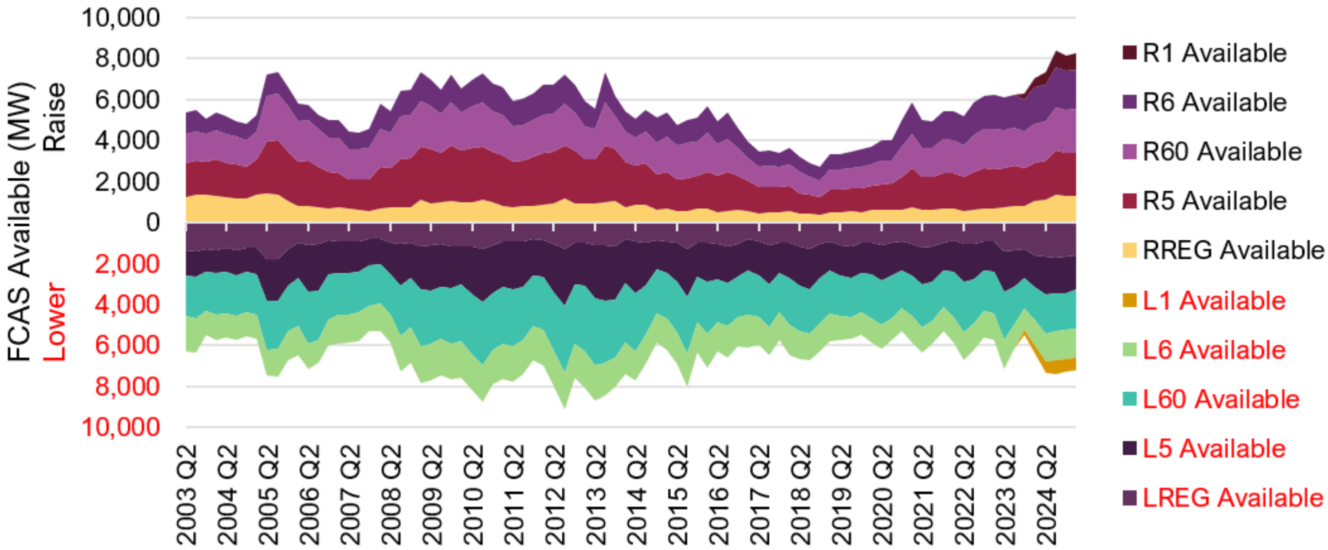
The available market supply of FCAS must be sufficient to meet the FCAS volume requirements and to facilitate market competition.

Figure 18 shows quarterly average actual availability of FCAS in the NEM (Lower availability is provided on the negative axis). Actual availability refers to the calculated availability of each FCAS each trading interval after all relevant scaling due to the FCAS trapezium and other unit constraints is applied. AEMO publishes more information about these internal calculations on its website[14].

Insight: FCAS availability has fluctuated since the start of the FCAS markets. A general reduction in availability occurred between 2013 and 2019, which may be associated with the period of declining frequency performance of the NEM. However, AEMO notes that all FCAS markets were fully supplied during this period so declining availability of FCAS cannot be the sole reason for the decline in observed frequency performance. Since 2019, a sustained increase in FCAS availability has been seen due to the emergence of new FCAS technologies such as large-scale and small-scale batteries, as well as IT platforms to harness aggregated consumer and commercial energy resources.

[14] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/fcas-model-in-nemde.pdf?la=en.

Figure 18 Quarterly average FCAS market availability, stacked, 2003 to 2025



FCAS prices

The market clearing price of each ancillary service in each region is a key indicator of FCAS supply availability for the prevailing conditions.

Figure 19 shows quarterly average FCAS prices after grouping together the regional prices into a single average NEM price for each trading interval.

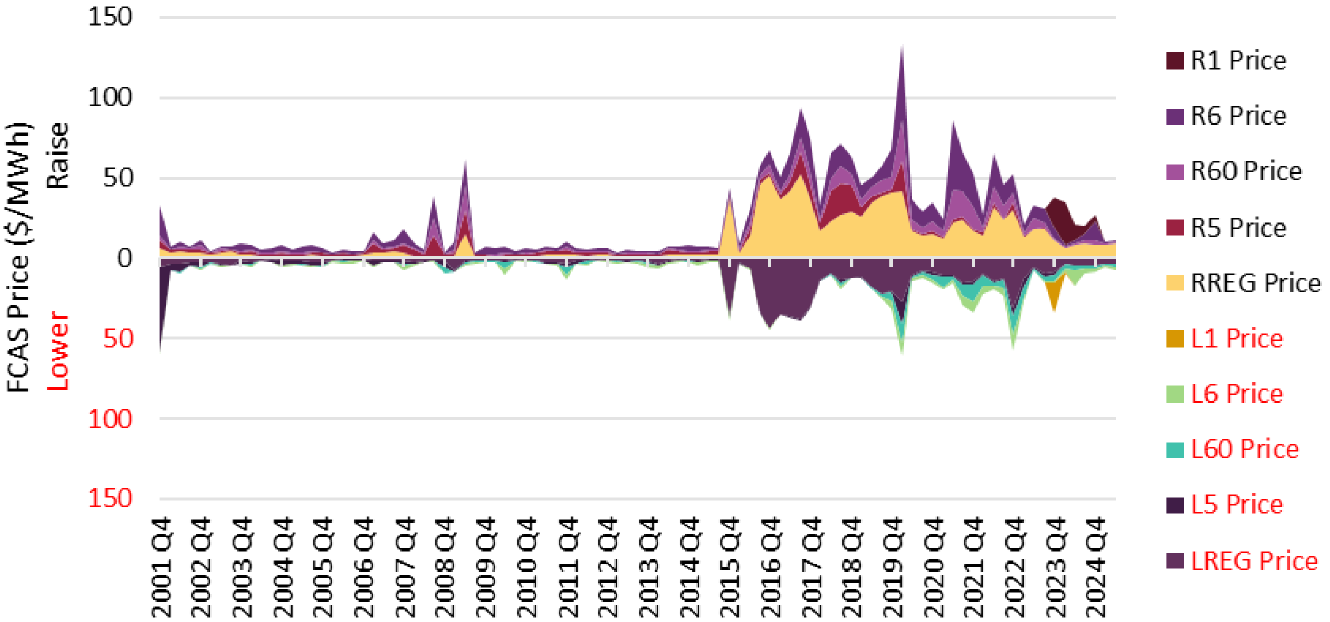
Insight 1: FCAS prices were lower from the start of the FCAS markets until 2016 compared to the period from 2016 to 2025. A number of factors escalated prices from 2016, including:

- Local regional regulation requirements in South Australia after the black system in 2016.
- Increasing FCAS requirements as seen earlier in Figure 3.
- Decreasing availability of FCAS supply as seen earlier in Figure 4.
- Increasing wholesale energy prices, which are co-optimised with FCAS prices.
- Increasing FCAS market participant concentration.

Insight 2: Raise FCAS prices have been consistently higher than Lower FCAS prices. The higher Raise FCAS prices are likely due to:

- The greater average requirement for Raise FCAS as seen above in Figure 17.
- The greater average availability of Lower FCAS supply as seen above in Figure 18.

Figure 19 Quarterly average FCAS market prices, all regions, stacked, 2001 to 2025



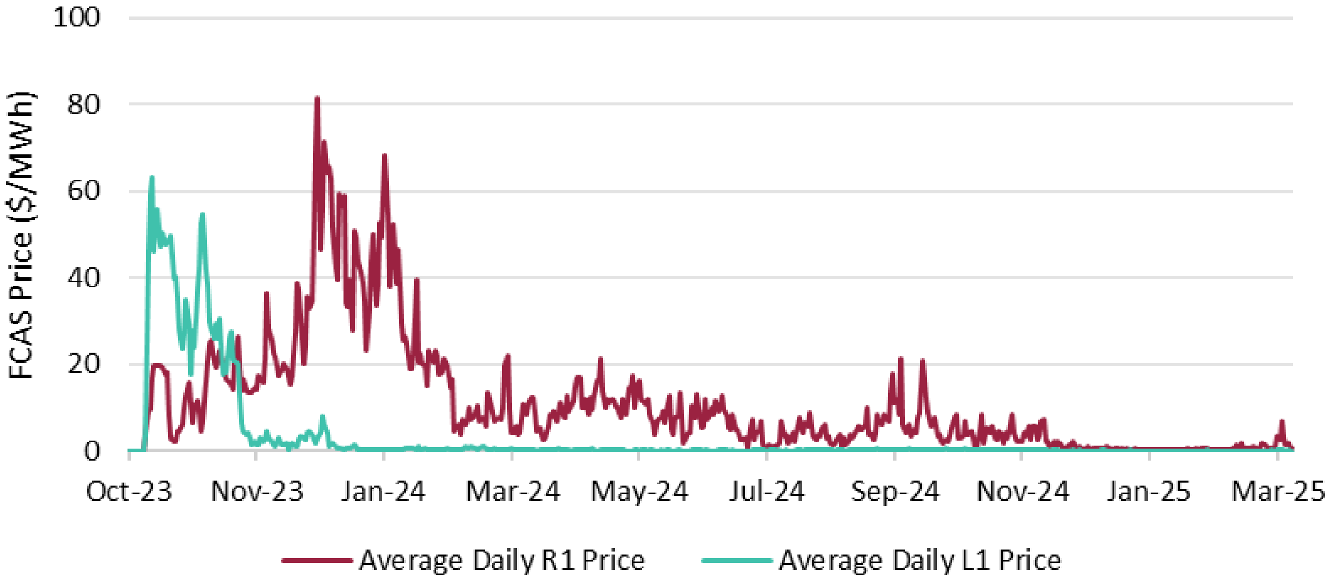
Introduction of Very Fast contingency FCAS markets

In 2023 new FCAS markets were added to the NEM for the first time since 2001. The introduction of the Very Fast contingency FCAS markets is considered an important reform to futureproof the NEM as inertia in the grid declines. Lower inertia will lead to faster changes in system frequency. The prior existing Fast contingency FCAS market was considered unable to guarantee the required speed of response during future contingency events. A Market Ancillary Service Specification (MASS) consultation was completed in 2023 to finalise the parameters of the new market ancillary services.

Figure 20 shows daily average Very Fast contingency FCAS prices since 9 October 2023 when the new market began operating.

Insight: Very Fast contingency FCAS markets experienced periods of elevated prices in the initial months following the introduction of both services. Since March 2024, prices have settled to lower values, likely due to increasing supply of Very Fast contingency FCAS.

Figure 20 Daily average Very Fast contingency FCAS prices, October 2023 to April 2025



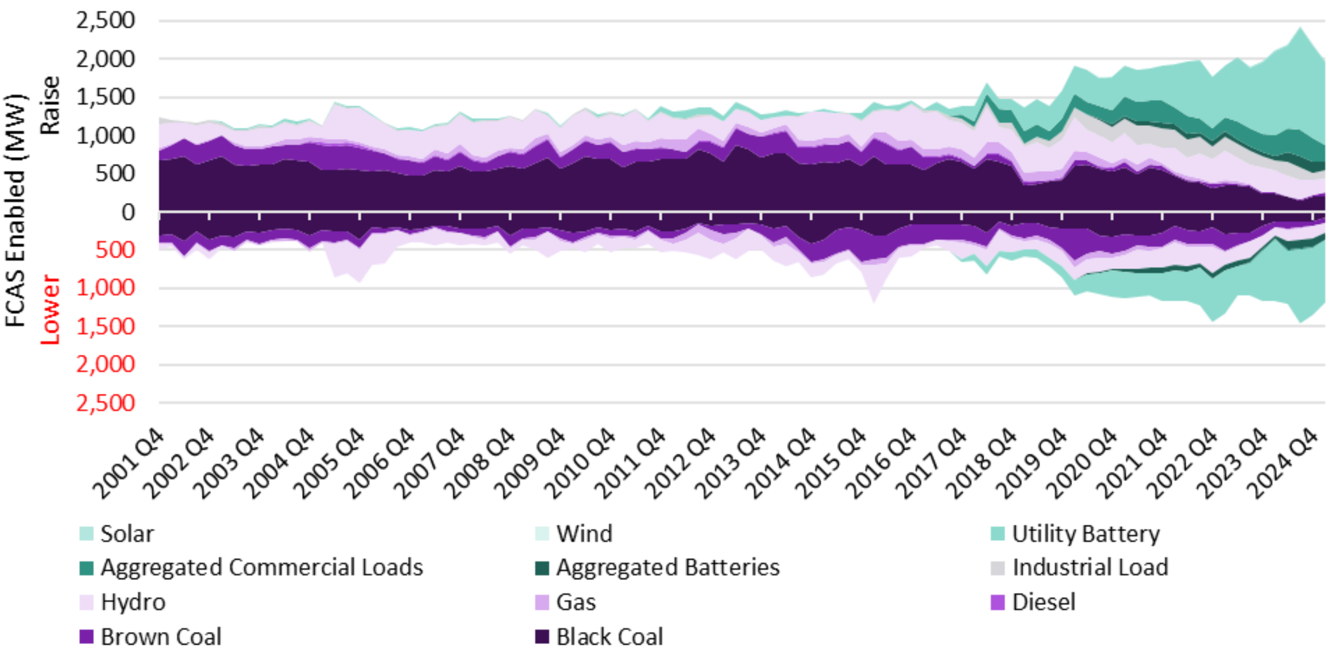
FCAS supply technologies

FCAS is supplied by a number of technologies that have demonstrated compliance with the MASS.

Figure 21 shows changes in the composition of FCAS supply by fuel type since the start of the FCAS markets.

Insight: FCAS is increasingly supplied by technologies that have emerged since 2017. Despite increasing FCAS requirements, the absolute amount of FCAS supplied by synchronous units has been decreasing and now constitutes less than 50% of all FCAS.

Figure 21 Quarterly average FCAS enabled by fuel type, stacked, 2001 to 2025



FCAS from non-synchronous resources

FCAS from non-synchronous resources has been emerging for some time in the NEM as new technologies have demonstrated their ability to provide FCAS. The NEM power system will operate at higher levels of non-synchronous resources in the next five years due to the ongoing energy transition. Industry and AEMO in collaboration are delivering an Engineering Roadmap to resolve the technical issues of operating the NEM using up to 100% non-synchronous resources[15]. It is therefore important to establish that non-synchronous resources can meet the operational requirements for FCAS. AEMO is monitoring frequency performance to confirm FCAS from non-synchronous resources can provide 100% of the NEM's FCAS if required.

Figure 22 shows the quarterly average FCAS enablement by control technology type.

Insight 1: A sustained increase in FCAS enablement from non-synchronous resources has been observed since 2017, with a corresponding reduction in FCAS enablement from synchronous resources. Two distinct new non-synchronous control technology types – IBR FCAS and switching FCAS – have emerged, which together provided approximately 78% of all FCAS in the most recent quarter examined (Q1 2025). Analysing individual FCAS control technology types is important due to their different control characteristics and the nature of frequency response provided by each.

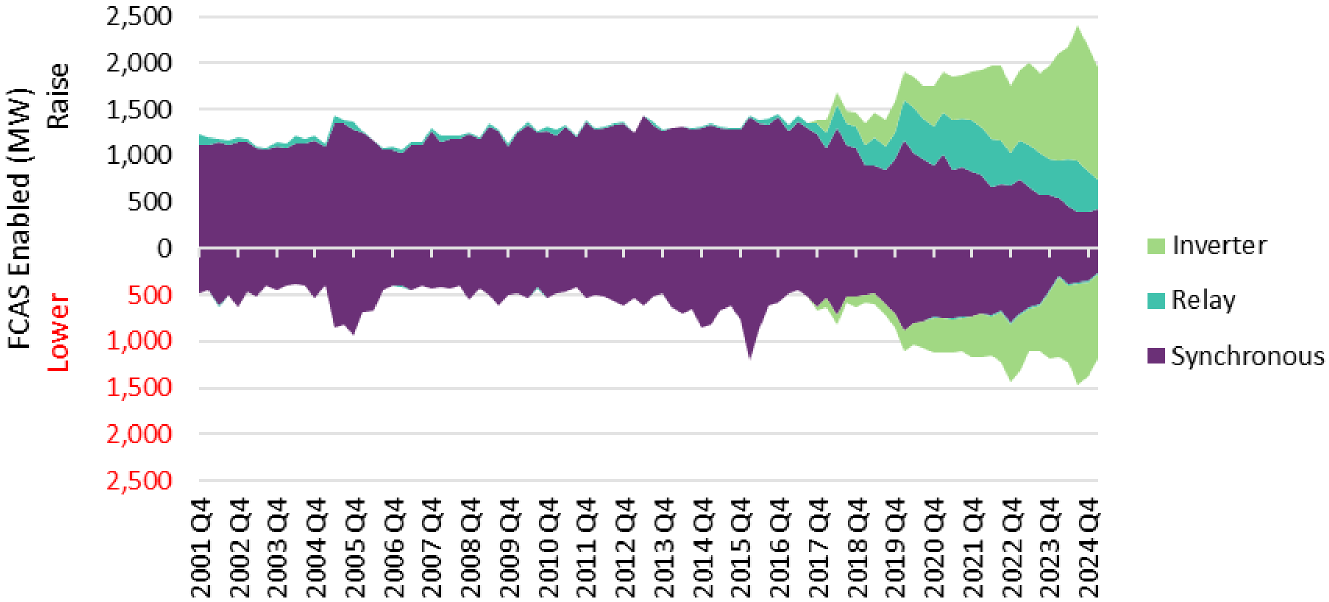
- **IBR FCAS** – the first IBR technology to provide FCAS was registered in 2017[16]. This control technology type reflects the growth in utility-scale and residential-scale battery energy storage systems (BESSs), as well as small amounts of wind and solar units providing FCAS.
  - *Controller characteristics*: IBR FCAS units are characterised by accurate changes in active power in response to changing system frequency. Their response to frequency changes is within hundreds of milliseconds.
- **Switching FCAS** – FCAS controlled by a frequency-triggered relay has been used historically on large generating and load units to provide large step changes in active power. Since 2016, the proportion of FCAS supplied by switching controller technology has grown due to the emergence of new aggregators of commercial loads which are well-suited to providing step changes in active power when a frequency relay is triggered by a frequency event.
  - *Controller characteristics:* switching FCAS units can provide reliable step changes in system load at certain frequency trigger settings. In general, switching controllers do not provide continuous adjustment of active power in response to system frequency. Switching controllers participating in contingency FCAS provide a step change in NEM system load to assist frequency recovery back to near 50 Hz.
- **Synchronous FCAS** – synchronous FCAS remains an important part of the FCAS supply in the NEM. These units will continue to be required to meet FCAS requirements at times of limited VRE and energy storage availability.
  - *Controller characteristics:* synchronous FCAS units provide frequency control in proportion to the frequency deviation from 50 Hz using governor control systems. These systems are well-tuned in the NEM power system after many years of operating experience.

Insight 2: The ongoing transition of the NEM power system and its sources of FCAS will necessitate continual review and refinement to ensure the system benefit of FCAS is maintained as the underlying FCAS technologies evolve.

[15] See https://aemo.com.au/en/initiatives/major-programs/engineering-roadmap.

[16] Hornsdale Power Reserve (HPRG1).

Figure 22 Quarterly average FCAS enabled by control technology type, stacked, 2001 to 2025



Priority action

- AEMO will monitor and review the operation of FCAS control technology types.

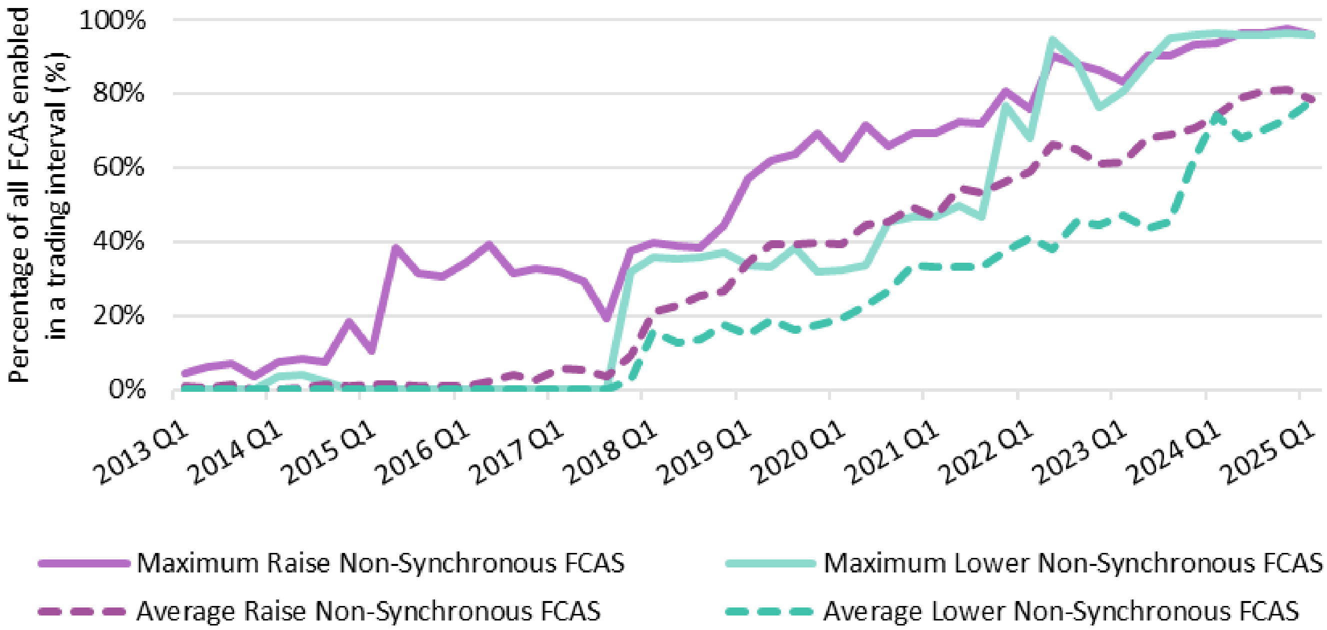
  AEMO must ensure that each FCAS control technology continues to perform well under a range of conditions. Ensuring an effective mix of FCAS control technologies at all times is not guaranteed by the technology-neutral FCAS market, and AEMO will consider whether minimum amounts of any particular technology are required based on operational evidence.

Figure 23 shows the quarterly maximum and average proportion of all FCAS supplied by non-synchronous resources.

Insight: Non-synchronous resources have been supplying increasing proportions of all FCAS markets. It is likely that trading intervals will occur soon where 100% of FCAS is supplied by non-synchronous resources.

- The trading interval of highest non-synchronous Raise FCAS supply occurred at 1825 hrs on 21 November 2024, when non-synchronous units supplied 97.46% of all Raise FCAS markets.
- The trading interval of highest non-synchronous Lower FCAS supply occurred at 0335 hrs on 4 May 2025, when non-synchronous units supplied 96.35% of all Lower FCAS markets.
- The trading interval of highest non-synchronous Raise and Lower combined FCAS supply occurred at 2025 hrs on 19 May 2025, when non-synchronous units supplied 95.68% of all FCAS markets.

Figure 23 Quarterly maximum and average FCAS enablement from non-synchronous resources by trading interval, 2013 to 2025



Aggregated FCAS facilities

The development of aggregated ancillary service facilities, or virtual power plants (VPPs), in the NEM for providing FCAS has taken two distinct pathways for two emerging FCAS resources:

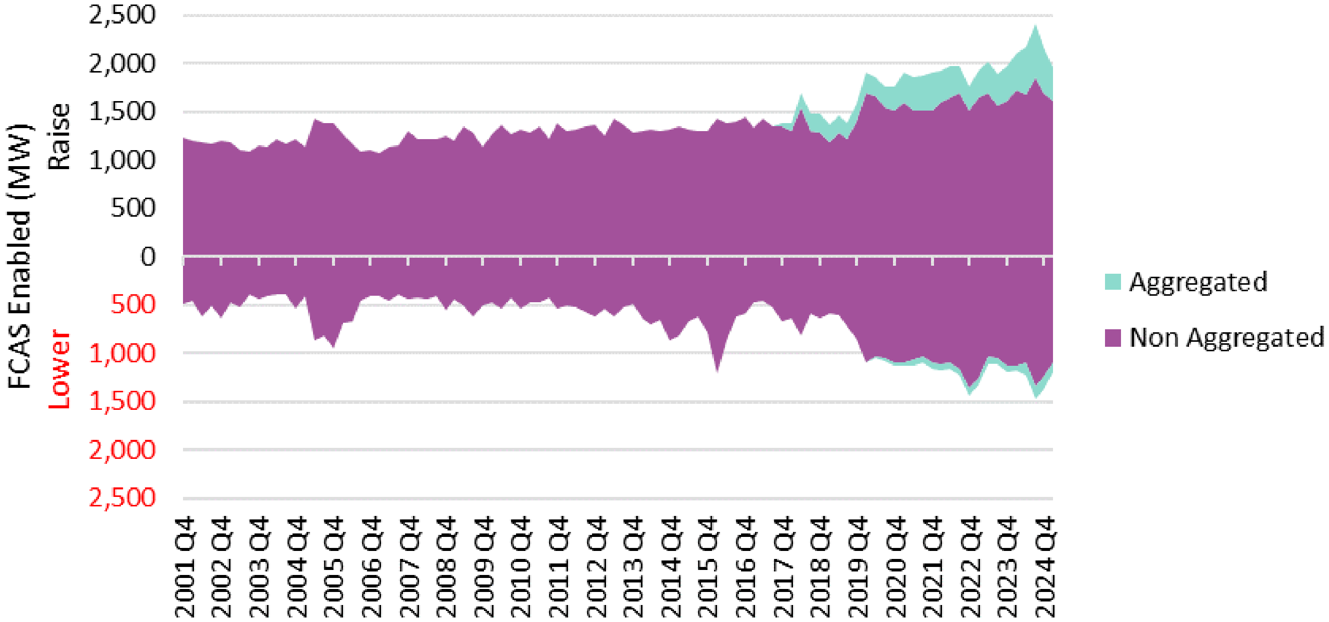
- **Aggregated commercial resources** – the first aggregated ancillary service facilities in the NEM were aggregations of commercial loads, which were co-ordinated remotely to provide frequency response using switching controller relays programmed to activate at allocated frequency trigger settings. A small number of such units have a long history of participation in FCAS in the NEM. Registration of these types of FCAS resources gained pace from 2017 when new sources of FCAS capacity were operationalised.
- **Aggregated residential resources** – the VPP Demonstrations Trial began in 2019 to facilitate the introduction of VPP platforms in the NEM[17]. Developments in consumer energy resources (CER) and IT technologies had matured to a stage where VPP market applications were considered viable to participate in the NEM in a regulatory sandbox environment. The Trial focused on facilitating FCAS rather than energy market participation for a number of technical and regulatory reasons.

Figure 24 shows the quarterly average enablement of all FCAS markets provided by aggregated ancillary service facilities. Some NEM units participate in FCAS as an aggregation of units, a practice which is most common among hydro units. In these cases, these units are in a single location and not counted here as a VPP.

Insight: VPPs are providing an increasing portion of FCAS in the NEM. AEMO considers the VPP Demonstrations Trial significant to the expansion of availability of FCAS supply provided by VPPs.

[17] See https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/virtual-power-plant-vpp-demonstrations.

Figure 24 Quarterly average FCAS enabled by aggregated status, stacked, 2001 to 2025



Trends in FCAS dispatch

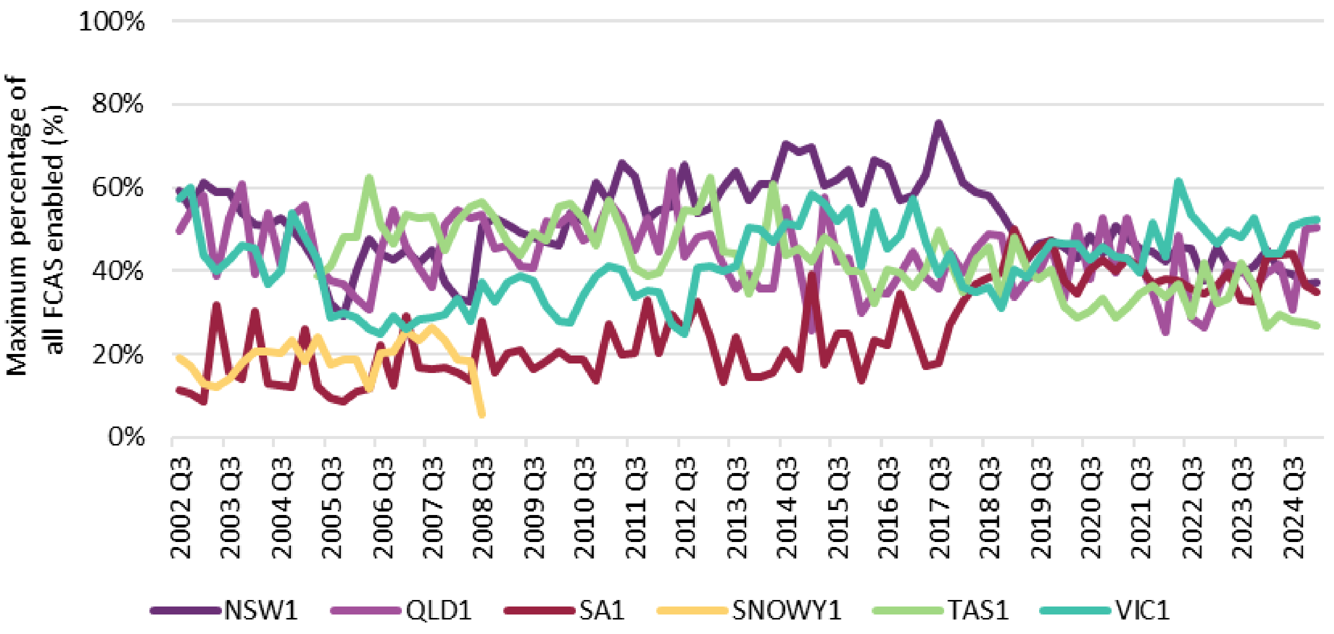
Regional concentration of FCAS

FCAS is procured using global requirements that can be supplied from any combination of FCAS units in any NEM region, with a caveat concerning Tasmania which at times is required to source FCAS locally due to the operation of Basslink, and in other regions when local FCAS procurement can be necessary for operational requirements.

Figure 25 shows the quarterly maximum percentage of FCAS requirements supplied by each region in a single trading interval since the start of the FCAS markets. Very Fast contingency FCAS has been excluded from this analysis due to its recent introduction.

Insight: The NEM has never experienced intervals where all FCAS was supplied by a single region, and in only a handful of cases has a single region supplied more than 70% of FCAS in a single trading interval. AEMO considers that this data is good evidence that global procurement of FCAS in the NEM produces acceptable regional distribution of FCAS enablement, despite the lack of a mechanism to ensure this outcome. Market competition and the nodal regional structure of the NEM encourage geographic distribution of FCAS units. FCAS is usually a secondary opportunity of operating most generating units and is not considered a factor in choosing a facility's location. Therefore, AEMO does not need to require specific regions to supply minimum amounts of FCAS to resolve the concerns above, with the notable exception of Tasmania due to the special circumstances relating to its single HVDC interconnector.

Figure 25 Quarterly maximum percentage of all FCAS markets supplied by each region in a single trading interval, 2002 to 2025



Priority actions

- AEMO will review the aggregate generator frequency response to ensure power system security can be maintained within network limits as IBR with very fast frequency control are connected, and impose limits on frequency response if required.

  The aggregation of rapid frequency response resources in some network sub-regions may not be optimal and create undesirable power flows over particular network locations in response to significant contingency events elsewhere in the NEM.

- AEMO will monitor and review the regional distribution of FCAS procurement.

  There is no constraint to prevent all FCAS from being sourced in a single region. Procuring all frequency control reserves within a single region may not be an optimal power system outcome. Key concerns include:

  1. *Possibility for the region to be islanded from the NEM, leaving no FCAS available in the remaining NEM until the first NEMDE solution that incorporates the invoked separation constraints.*
  2. *Risk of exceeding network limits when the FCAS response is delivered due to a contingency occurring in another region.*

Unit concentration of FCAS

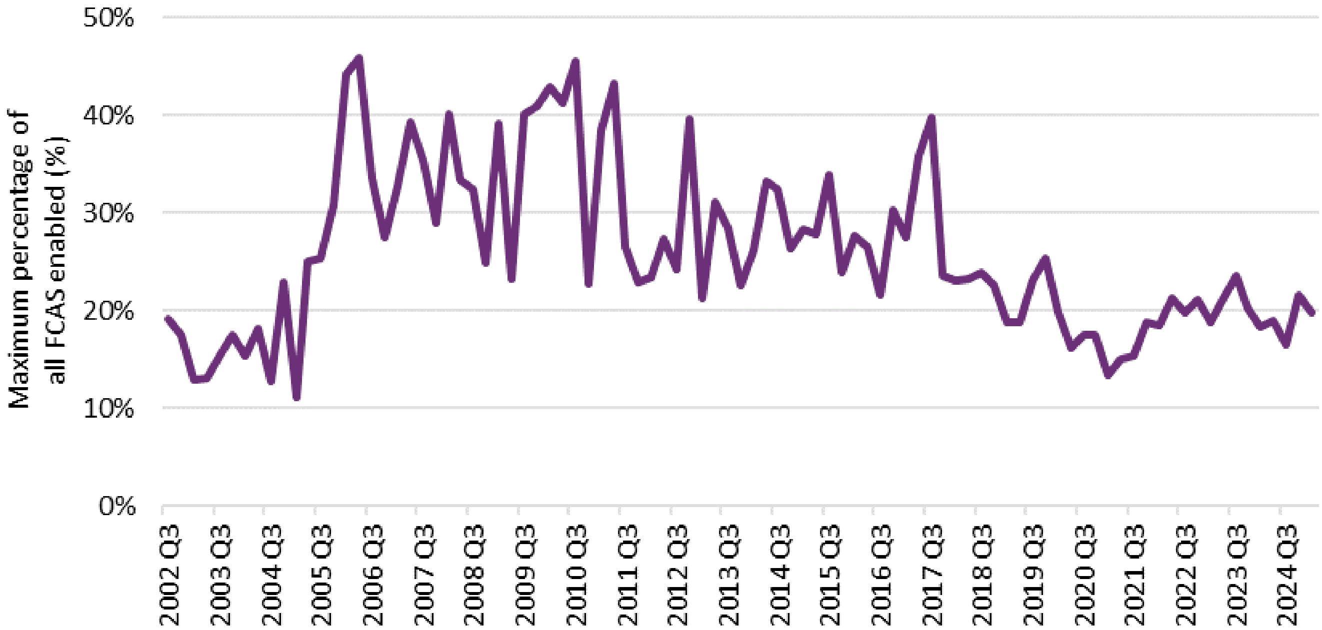
Alongside the concern regarding regional concentration of FCAS procurement exists a parallel concern that single FCAS units in the NEM are increasingly capable of supplying large portions of all FCAS requirements. Utility-scale batteries have emerged in recent years as a technology well-suited to participating in the bidirectional (Raise and Lower) FCAS market structure and across all five service types (Very Fast, Fast, Slow, Delayed, Regulation) in the same trading interval. These are likely to be the first technology capable of fulfilling all FCAS market requirements from a single unit in a single trading interval due to the following factors:

- Modular battery design does not provide an upper limit on nameplate capacity, whereas most synchronous units have upper limits due to mechanical and practical difficulties encountered with increasing unit sizes.
- Batteries can register a high percentage of their nameplate capacity as FCAS capacity due to their fast controls. In practice AEMO limits the FCAS capacity of batteries to approximately 57% of nameplate capacity. In contrast many synchronous units have an FCAS response capability to provide 5-10% of nameplate capacity as FCAS.
- There are already several large battery facilities individually capable of providing all regulation FCAS requirements under normal circumstances.

Figure 26 shows the quarterly maximum percentage of FCAS requirements supplied by a single unit in a single trading interval since the start of the FCAS markets. Very Fast contingency FCAS has been excluded due to its recent introduction.

Insight: The NEM has never experienced intervals where all FCAS was supplied by a single unit, and in only a handful of cases has a single unit supplied more than 40% of FCAS in a single trading interval. AEMO further notes this metric has declined since approximately 2010 and stabilised near 20% since 2019, which AEMO considers reasonable for resilient power system outcomes.

Figure 26 Quarterly maximum percentage of all FCAS markets supplied by a single unit in a single trading interval, 2002 to 2025



Priority action

- AEMO will monitor and review the distribution of FCAS procurement amongst NEM units.

  There is no constraint to prevent all FCAS from being sourced from a single unit. Procuring all frequency control reserves from a single unit may not be an optimal power system outcome. The key concern is the possibility for the unit to trip, leaving no FCAS available in the NEM until the next NEMDE solution.

1.2.4 Case Study 1: NEM system of frequency control in action on 13 February 2024

Event summary

A significant series of power system events unfolded in Victoria on 13 February 2024. Transmission tower collapses along the Moorabool (MLTS) – Sydenham (SYTS) No. 1 and 2 500 kilovolts (kV) lines west of Melbourne initiated a disconnection of four Loy Yang A generating units and the Dundonnell and Yaloak South Wind Farms. Approximately 2,690 MW of generation was lost in Victoria over two minutes and approximately 1,000 MW of customer load was shaken off. A full summary of events is available on AEMO's website[18].

This event had significant frequency impacts and can be used as a case study of the NEM system of frequency control operating to correct a large supply and demand imbalance. It is reviewed here in detail because the event experienced:

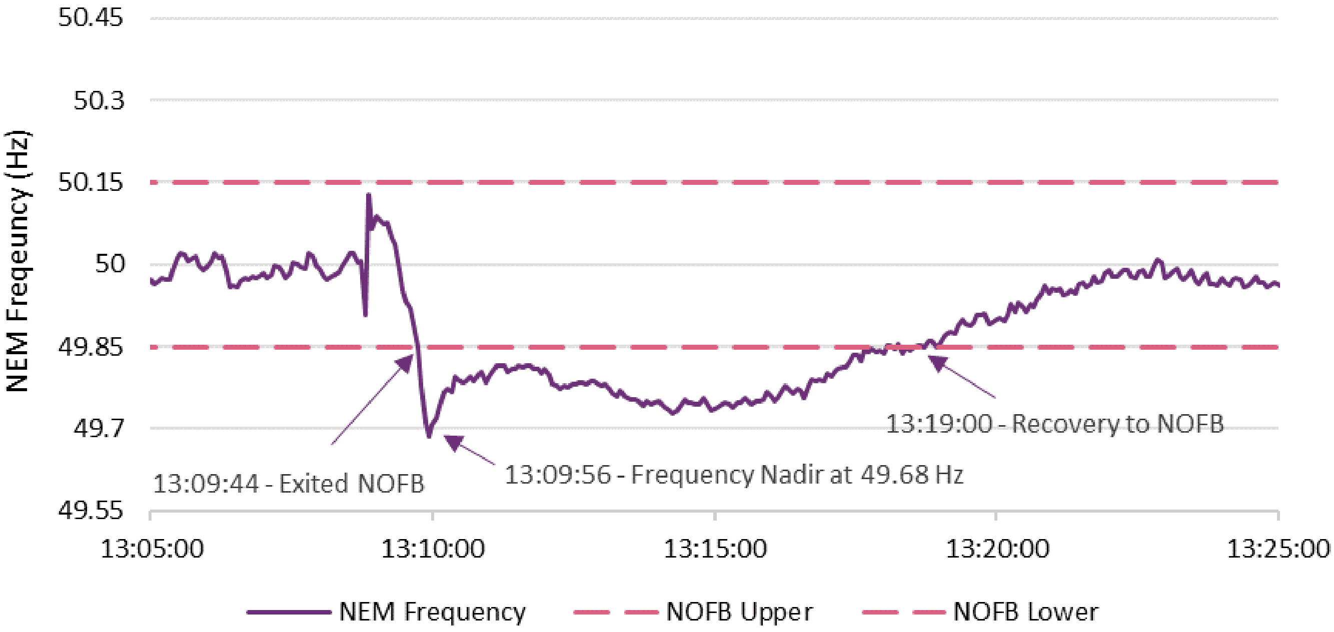
- Significant load and generation contingencies sizes, with a demand loss of approximately 1,000 MW followed by a supply loss of approximately 2,690 MW.
- Positive and negative frequency deviations, with system frequency increasing to 50.12 Hz, then decreasing to 49.68 Hz, then taking approximately nine minutes to recover to within the NOFB.
- Operation of all NEM frequency control sub-systems, providing the opportunity to evaluate these systems in action.
- A temporary increase of the regulation FCAS requirement to 450 MW in effect prior to the event for unrelated reasons.

Furthermore, this event occurred less than 18 months ago and is therefore a good demonstration of the current performance of the NEM system of frequency control in response to a complex sequence of power system events.

Figure 27 shows the system frequency during the event. An initial over-frequency period was observed at 1308 hrs due to the load shake-off at the time of the non-credible trip of transmission lines. Following this, a period of extended under-frequency was experienced due to the large-scale generation loss.

[18] See https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/preliminary-report---loss-of-moorabool---sydenham-500-kv-lines-on-13-feb-2024.pdf.

Figure 27 System frequency during 13 February 2024 event



NEM system of frequency control response

The NEM system of frequency control comprises multiple systems that work together in a contingency event.

Figure 28 shows the estimated response of the various NEM control systems in response to the large supply and demand deficit, with AEMO making the following observations of system performance.

Insight: There was a:

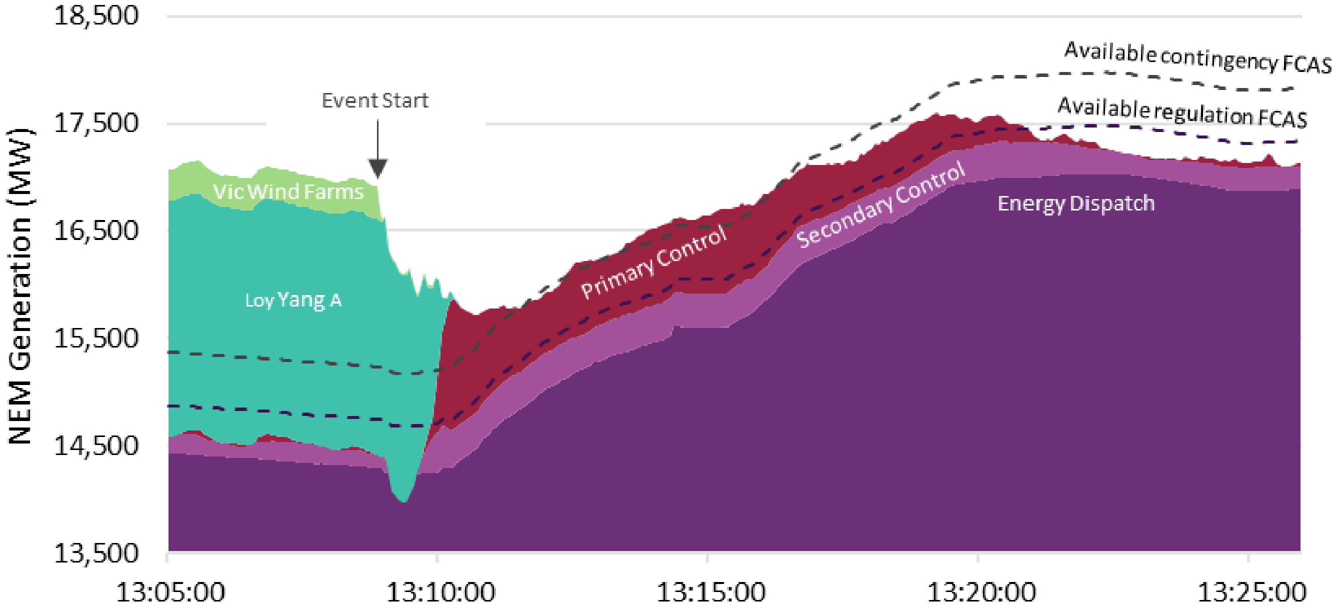
- Rapid reduction in generation due to primary control at the start of the contingency in response to over-frequency.
- Rapid increase in generation due to primary control to approximately 1,200 MW above the energy dispatch baseline following loss of four Loy Yang A units.
- Utilisation of approximately 350 MW out of 450 MW of available secondary control (Raise regulation FCAS). AEMO found the full quantity of Raise regulation FCAS was not used due to some units enabled for Raise regulation FCAS having their primary control push the units outside their secondary control limits, at which point AGC will not request further secondary control.
- Re-dispatch of the energy market at 1310 hrs for the 1315 hrs trading interval which acted to replace lost generation. The contingency event occurred shortly before 1310 hrs, which allowed NEMDE to rebalance the market generation immediately. If the event had occurred shortly after 1310 hrs, NEMDE would have not assisted until the beginning of the 1320 hrs trading interval starting at 1315 hrs.
- Gradual reduction in primary control and secondary control from 1320 hrs as system frequency recovered to the NOFB. NEMDE had ramped the remaining NEM generation fleet to replace the primary and secondary control services.

AEMO considers this event demonstrates effective frequency management in the NEM and satisfactory operation of the NEM system of frequency control to maintain frequency within the FOS requirements during a large non-credible contingency event.

Note that:

- Figure 28 excludes semi-scheduled and non-scheduled generating units which do not provide significant frequency response in aggregate, with the exception of the Victorian wind farms that reduced generation by control scheme at the start of the event. AEMO reviewed this period and found no significant errors in the aggregate dispatch of these units that may have contributed to the frequency event.
- Primary control has been estimated as all generator response above the combined energy dispatch trajectory and regulation FCAS requested. Primary control in this instance does not differentiate between units enabled for contingency FCAS and units providing mandatory primary frequency response.

Figure 28 NEM system of frequency control in operation on 13 February 2024, generation output by control type



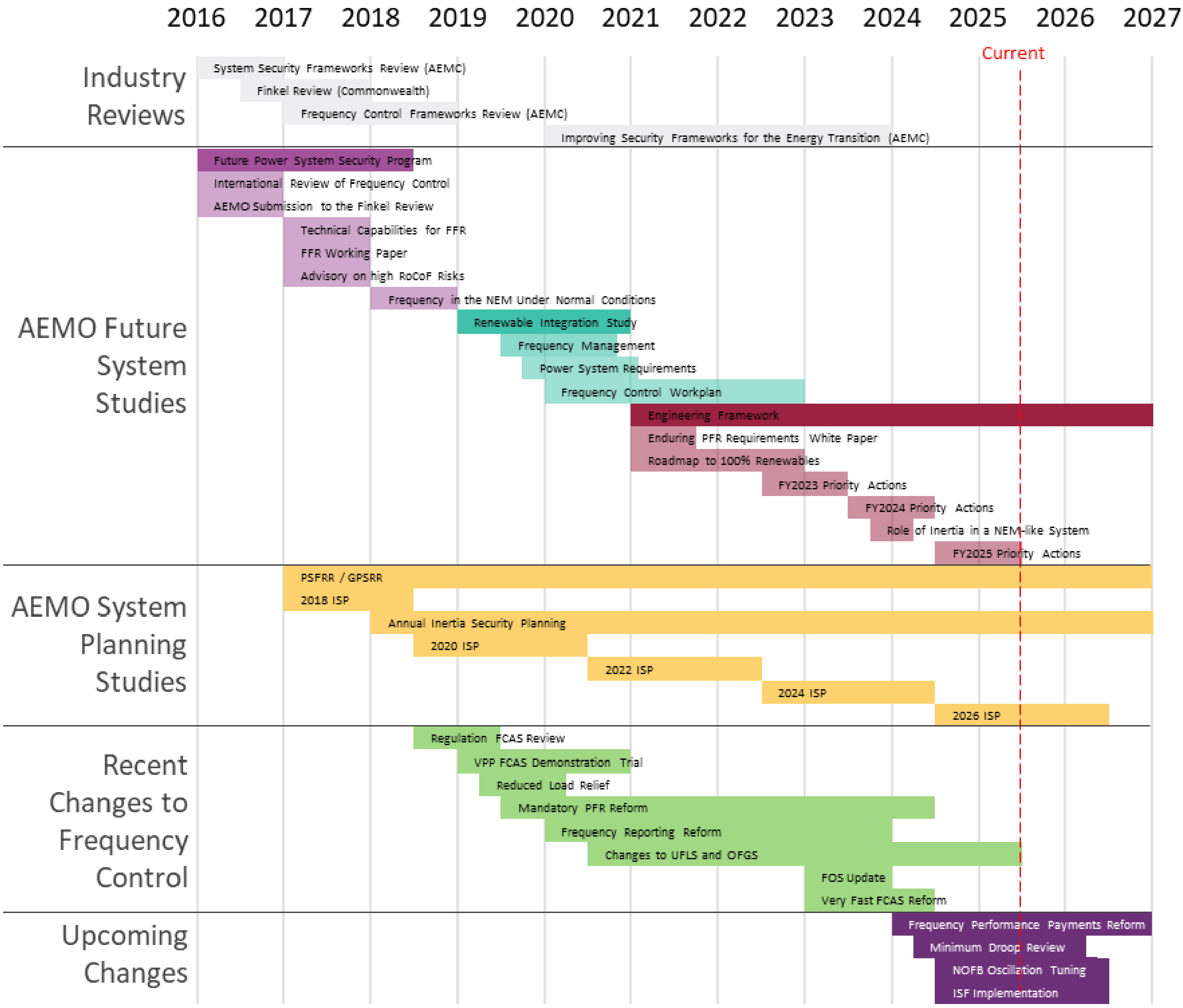
1.3 Frequency control reviews and reforms

Frequency control arrangements in the NEM are subject to regular review and reform.

Figure 29 provides an overview of recent frequency reviews and reforms, and estimated timeframes for their undertaking. Each identified workstream is discussed in further detail below in Table 3 and Table 4 regarding its impact on the frequency control landscape.

This figure is for illustrative purposes only and should not be relied on for a detailed understanding of project timelines or resource commitment. Every effort has been made to include relevant workstreams.

Figure 29 Recent and upcoming reviews, studies and changes relevant to frequency control



1.3.1 Recent frequency control reviews and studies

Table 3 is a summary of recent reviews and studies concerning frequency control in the NEM, with an assessment of their impact on the frequency control landscape.

Table 3 Recent frequency control reviews and studies

Recent reviews and studies	Impact on frequency control landscape
Industry Reviews	Significant recent industry reviews with direct relevance to frequency control arrangements in the NEM include: • System Security Frameworks Review, 2016 (Australian Energy Market Commission [AEMC]). • Finkel Review, 2017 (Commonwealth). • Frequency Control Frameworks Review, 2017 (AEMC). • Improving Security Frameworks for the Energy Transition, 2024 (AEMC).

Recent reviews and studies	Impact on frequency control landscape
	These review processes have recommended or supported many of the reforms enacted recently in the NEM's frequency control arrangements, including: • Review of the FOS. • Mandatory PFR Reform. • Very Fast contingency FCAS Reform. • Annual Inertia Security Planning. • Integrated System Planning.
AEMO Future System Studies	Three distinct work programs have progressed AEMO's future system studies with regard to frequency: 1. Future Power System Security Program, 2016 The Future Power System Security Program was established to investigate emerging power system concerns as the percentage of VRE in the NEM power system grew rapidly. The program was focused on questions of primary frequency response, RoCoF and the potential of new technologies providing fast frequency capability. Key milestone publications regarding frequency control include: • *International Review of Frequency Control.* • *AEMO Submission to the Finkel Review.* • *Technology Capabilities for Fast Frequency Response.* • *Fast Frequency Response in the NEM.* • *Advisory on Equipment Limits Associated with High RoCoF Risks.* 2. Renewable Integration Study (RIS), 2019 The Renewable Integration Study built on the work of the Future Power System Security Program. Key milestone publications regarding frequency control include: • *Power System Requirements* – AEMO published for the first time a comprehensive list of power system capabilities required to operate a power system, of which frequency management is considered a central capability. • *RIS Stage 1 – Appendix B: Frequency Control* – The RIS Stage 1 report provided a detailed analysis of the technical issues to be encountered as the NEM power system transitions to a new generation. • *Frequency Control Work Plan* – The Frequency Control Work Plan was published as a recommendation of the RIS Stage 1 report to co-ordinate the various workstreams concerning frequency control in the NEM and identify key future projects to be prioritised. The prioritised list of 21 workstreams have been largely actioned and completed as of July 2025. 3. Engineering Framework and Roadmap, 2021 The Engineering Framework and Roadmap superseded the RIS as AEMO's primary program of work to address emerging NEM power system issues already or not yet identified. The Engineering Framework has been a major collaborative undertaking between AEMO and industry to provide an ongoing forum for the discussion and progression of issues relating to all aspects of future power system operation, including frequency control. Key milestone publications regarding frequency control include: • *Engineering Roadmap to 100% Renewables.* • *Engineering Roadmap Priority Actions for FY23, FY24 and FY25.* • *Enduring primary frequency response requirements for the NEM.* • *Role of Inertia In a NEM-Like System.* • *100% Inverter Based Resource Generation Study – Tasmania Region.*
AEMO System Planning Studies	Two programs have progressed AEMO's system planning efforts with regard to frequency: 1. Power System Frequency Risk Review (PSFRR) and General Power System Risk Review (GPSRR). 2. Inertia Requirements Methodology and Inertia Reporting.

1.3.2 Recent changes to frequency control arrangements

Table 4 is a summary of recent changes to frequency control arrangements in the NEM, with an assessment of their impact on the frequency control landscape.

Table 4 Recent changes to frequency control arrangements

Recent change	Impact on frequency control landscape
Review of Regulation FCAS Volumes, 2019	Frequency performance improved throughout 2019 in the NEM as the increased requirement for regulation FCAS was implemented. AEMO concludes that the review of regulation FCAS was at least partly responsible for stabilising frequency performance inside the NOFB.
Reduction of assumed Load Relief, 2019	AEMO is satisfied with the review of load relief and did not observe any adverse impact on the frequency control landscape from the implemented change. Higher quantities of contingency FCAS have been enabled across all services since the change due to the reduction in assumed benefit from load relief.
Introduction of Mandatory PFR, 2020	The introduction of mandatory PFR improved system frequency by some margin within a matter of months. The reform tightened the distribution of system frequency around 50 Hz and reduced the number of frequency excursions outside the NOFB without a contingency. AEMO also observes better frequency containment and frequency recovery following contingency events. AEMO has greater confidence that the NEM power system will be well-controlled following non-credible contingency events. The market IT systems require time to be reconfigured in the immediate minutes following a major power system contingency, such as the separation of a region. Widespread primary frequency response improves system control and stability during these events until the market systems and operators can assert reconfigured control. The mandatory PFR reform has broken new ground internationally requiring primary frequency response from intermittent IBR generation. This effort has been a technical challenge requiring the collaboration of AEMO and industry but will be essential to ensure system stability in periods of high-IBR dispatch in the future.
Introduction of Frequency Reporting Requirements, 2020	AEMO considers this requirement has improved the quality and availability of frequency analysis in the NEM. The weekly reports provide 4-second frequency data in an accessible format which is used by many stakeholders. The quarterly reports provide a detailed review of frequency events and FOS exceedances.
Completion of VPP Demonstration Trial, 2022	The VPP demonstration trial is considered a success by AEMO. The share of contingency FCAS provided by aggregated units has increased. Further the trial is considered a valuable stepping stone on the path to VPPs providing energy dispatch services in the NEM.
Review of the FOS, 2023	The addition of an explicit RoCoF limit in the FOS will assist the industry to navigate low-inertia dispatch scenarios. RoCoF is expected to increase as inertia decreases and there is good evidence to support limiting RoCoF on the NEM power system to avoid unnecessary protection trips on generating units and equipment. The primary tools to ensure the RoCoF limit is met will be dispatch of Very Fast contingency FCAS and maintaining a minimum level of NEM-wide inertia at all times. The removal of the limit on time error accumulation is not considered to be consequential to power system operations. Time error is considered a useful measure for guiding AGC and identifying issues in the NEM system of frequency control but does not require strict regulation itself. AEMO can and does reset time error to zero when it reaches quantities that are no longer useful to the above purposes.
Introduction of Very Fast contingency FCAS, 2023	AEMO considers the introduction of the Very Fast contingency FCAS markets to be a successful reform without adverse consequences for frequency control. In 2001 average NEM inertia was approximately 110,000 MWs. AEMO analysis found that the contingency FCAS requirements in place would not support operating the NEM down to reasonably foreseeable lower levels of inertia. The introduction of the Very Fast contingency FCAS markets will support the NEM down to the minimum required level of NEM-wide inertia to be maintained at all times.
Changes to UFLS and OFGS, 2020-2025	AEMO is making continual improvements to the design and operation of regional UFLS and OFGS systems in the NEM. Significant changes over recent years include: • For UFLS: – Review and reassignment of load block trigger settings. – Adoption of reverse flow blocking relays. – Removal of larger embedded gen from UFLS feeders. – Establishment of real-time UFLS visibility via SCADA. • For OFGS: – Implementation of OFGS in SA, Western VIC and Queensland, joining Tasmania as regions with OFGS. – AEMO will continue to assess the need for OFGS in NSW and Eastern Victoria.

1.3.3 Upcoming changes to frequency control arrangements

Table 5 is a summary of upcoming changes to frequency control arrangements in the NEM, with an assessment of their anticipated impact on the frequency control landscape.

Table 5 Upcoming changes to frequency control arrangements

Upcoming change	Anticipated impact on frequency control landscape
Introduction of ISF Rule Change, 2025	AEMO anticipates the primary impact of the ISF rule change on frequency control arrangements will be the implementation of a NEM-wide system inertia floor which will assist to maintain system inertia above the critical level required to operate the existing frequency control arrangements.
Review of Minimum Acceptable Droop, 2025	AEMO anticipates there will be better evidence for any minimum acceptable droop limit as a result of this work**.**
Tuning of NEM Frequency Oscillations, 2025	AEMO will report any significant findings of this work and resulting changes to system frequency outcomes.
Introduction of Frequency Performance Payments (FPP), 2025	AEMO anticipates the FPP reform will increase the incentives for providing good frequency control and increase the disincentive to generation performance that impacts negatively on frequency control.

Priority action

- AEMO will monitor and review the evidence for the minimum droop setting implemented on IBR units.

  The minimum droop setting allowed on IBR units was established in 2017 and may need to be updated to ensure it remains fit-for-purpose as higher amounts of IBR generation operate in the NEM.

1.3.4 Are all these changes working together?

AEMO is satisfied with the frequency control arrangements that have been implemented in the NEM since the introduction of market ancillary services. The evolution of these arrangements has kept pace with technological developments such as the emergence of IBR FCAS resources and the changing need for frequency control in the NEM.

1.3.5 Case Study 2: Implementing PFR on VRE units in the NEM

The Mandatory PFR reform has provided substantial benefits to frequency performance in the NEM since its initial implementation in 2020. AEMO considers the reform to be very successful overall in terms of the increased system stability and resilience it has provided. Nonetheless, PFR is not a set-and-forget mechanism. There remain questions about how PFR may perform in the longer term, especially given significant challenges around PFR from VRE sources, and ongoing work regarding how frequency performance is compensated.

AEMO has provided PFR implementation updates, with the last update in May 2023[19]. Nearly all scheduled generating units that were readily able to implement PFR have done so. However, there remain a significant number of semi-scheduled units, including units designed and commissioned after the rule change in 2020, which face challenges with providing PFR. Concerningly, these challenges will remain unless a significant amount of work and expense is undertaken by the affected parties. Significant issues include:

- Developing and implementing frequency response controls on semi-scheduled units that work reliably across all reasonable operating conditions, which has been technically and administratively challenging because semi-scheduled units:
  - Are software-controlled to a degree not typical of synchronous generating units.

[19] See https://aemo.com.au/en/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/primary-frequency-response.

- Have limited inherent frequency control capability, as they possess limited inertia and lack a constant energy source to deliver reliable frequency response in conventional manner.
- In many cases, were designed before the mandatory PFR reform. The design of their controls never envisaged providing continuous narrow-deadband frequency response capability and their technical hardware and software systems may not easily be updated to provide PFR.

- Most VRE original equipment manufacturers (OEMs) did not have proven frequency response controls to deploy to semi-scheduled units in the NEM. Developing and validating frequency response controls has been harder than anticipated and has required significant investment from AEMO and each OEM to progress forward. Different OEMs have different challenges and constraints on providing a working solution to meet the mandatory PFR obligations, and different levels of technical support and sophistication to resource this project in the Australian market.
- The co-ordination of specific changes to generator controls, such as implementing PFR, through the generator performance standards (GPS) framework is complicated despite the allowances in the NER for PFR as these changes often cannot be easily separated from other matters relating to a unit's GPS. Furthermore, the accessibility of technical resources needed to prepare, test and validate any proposed changes is limited.

Priority actions

- AEMO will complete the following action after financial operation of the Frequency Performance Payments (FPP) reform begins:
  - Review the adequacy of current PFR settings for future system requirements.

    The establishment of the current PFR settings outlined in the Primary Frequency Response Requirements (PFRR)[20] *in 2020 was completed in a different frequency control environment where AEMO's primary concerns were the poor control of system frequency due to limited primary response. AEMO needs to re-assess that these requirements remain fit-for-purpose following the implementation of the FPP reform.*
- AEMO will develop a pathway to finalise the implementation of PFR on semi-scheduled units.

  The challenges experienced while undertaking the PFR reform must be addressed to ensure new and existing semi-scheduled units in the NEM provide adequate aggregate PFR.

AEMO has experienced the practical challenges of co-ordinating a major change to a key component of the NEM system of frequency control through the implementation of the mandatory PFR reform. There may be future challenges of similar complexity as the NEM power system evolves along the range of ISP pathways, and the time and resources required to study and resolve these challenges should not be underestimated by AEMO or industry.

[20] See https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2024/primary-frequency-response-requirements-clean.pdf?la=en.

2 Outlook for NEM frequency

The NEM power system is changing and frequency control will remain satisfactory if power system requirements are met in an efficient and planned manner.

- The range of ISP pathways will create new risks and challenges for maintaining frequency control but also new opportunities for emerging frequency control technologies.
- Proactive reform will continue to evolve the NEM frequency control arrangements.

2.1 Outlook for the requirements for frequency control

2.1.1 ISP projections

The ISP is a roadmap for the transition of the NEM power system. The ISP includes discussion of system operability[21] and system security[22] considerations likely to be experienced in the future NEM power system but frequency control is not considered in great detail in the ISP optimisation process. The *ISP Methodology* published in June 2025[23] states:

"The ISP assumes the current NER in respect of primary frequency control together with contingency and regulation frequency control ancillary services (FCAS). It is assumed that the FCAS market will ensure sufficient headroom is available on generation or batteries, as well as provide signals for investment if needed. Given the wide range of potential sources of global FCAS providers, this is not seen to influence the ODP."

Nevertheless, the range of ISP pathways of the NEM can illuminate the likely development of frequency control arrangements in the NEM. AEMO projects the following outlook for the requirements of, or need for, frequency control. The ISP does not provide quantitative estimates of these projections but each projection can be evaluated in qualitative terms for potential impact and likelihood. AEMO has provided limited quantitative analysis below where possible.

2.1.2 Implications of the ISP projections for the requirements for frequency control

1. **Reduction in available synchronous inertia.**

AEMO's latest annual *Inertia Report* from December 2024 provides detailed projections of system inertia in the NEM regions in accordance with the ISP *Step Change* scenario[24]. This Technical Review will not examine these findings in detail. It is sufficient to confirm that average and minimum inertia in all NEM regions is expected to decline year-on-year as synchronous generation commitment in the market decreases. AEMO will soon be required to ensure a minimum level of inertia is available at all times in the NEM as a result of the ISF rule change commencing.

[21] See https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a4-system-operability.pdf?la=en.

[22] See https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a7-system-security.pdf?la=en.

[23] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp-methodology/isp-methodology-june-2025.pdf?la=en.

[24] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system_security_planning/2024-inertia-report.

2. **Increase in largest maximum contingency size due to development of large VRE projects, distributed photovoltaic (PV) disconnection and network augmentations creating new contingencies.**

Maximum contingency sizes in the NEM will likely increase across the range of ISP pathways, for the following reasons:

- At least one generating unit currently under construction will be larger than the largest existing single unit in the NEM[25]. In general, with VRE and BESS units there is no natural upper limit on unit size as typically exists with synchronous units due to engineering limitations. Larger VRE and BESS developments may be pursued to reduce site connection and construction costs.
- Increasing amounts of distributed energy resources (DER) across the range of ISP pathways are likely to increase the amount of DER at risk of tripping during a credible contingency, such as a network fault, which acts to increase contingency size. AEMO is continuing to investigate and manage the risk created by DER disconnection[26]. Corrective actions are being undertaken to mitigate these risks by increasing FCAS requirements, curtailing DER and improving DER fault ride-through compliance[27].
- The creation of renewable energy zones (REZs) in the NEM and the densification of VRE projects on existing transmission lines appears likely to increase maximum contingency sizes as more generation is likely to be affected by credible network contingencies. A trip of the Ballarat – Waubra – Ararat 220 kV line in Victoria can at times represent the largest credible contingency in the NEM due to a trip of this line disconnecting five wind farms with 837 MW of nameplate capacity. These contingencies can generally be handled by system constraints to limit their potential size. Well-planned REZ design will also help mitigate these risks.

3. **Increase in dispatch error due to VRE off-target dispatch error.**

Figure 15 (in Section 1.2.2) provides a valuable insight into the growth of VRE off-target dispatch error as the capacity of VRE in the NEM has increased since 2007. The intermittent characteristic of VRE units leads to aggregate dispatch errors between their aggregate actual generation at the end of each trading interval when compared to their aggregate forecast generation target from five minutes earlier. These dispatch discrepancies result in frequency deviations which are corrected by units providing primary and secondary control of frequency. It is likely that AEMO will need to increase the reserves of primary and secondary control systems through larger FCAS requirements as more NEM energy supply is provided by VRE.

4. **Reduction in net load under UFLS due to increasing distributed solar systems.**

The ISP forecasts strong growth in DER supply in the NEM, which will correspond with decreasing net load available for UFLS during the daytime. UFLS as an EFCS is discussed in detail in Section 1.2.2. UFLS is a proven system that has existed in all regions since before the start of the NEM. The design and operation of the various regional schemes has generally not been updated since the emergence of DER supply. The key concern is the UFLS disconnection of distribution-level feeders which may be supplying net generation to the wider power system, which may then accelerate the decline in system frequency. Individual NEM regions such as South Australia and Victoria are undertaking various programs to identify mitigations that will address this issue, but it is evident there will need to be substantial work to address what will be a fundamental challenge in the NEM power system across the range of ISP pathways.

[25] Waratah Super BESS – 850 MW, Kogan Creek Power Station – 744 MW.

[26] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation.

[27] See https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-connections/compliance-of-der-with-technical-settings.

2.2 Outlook for the available options to meet the requirements of frequency control

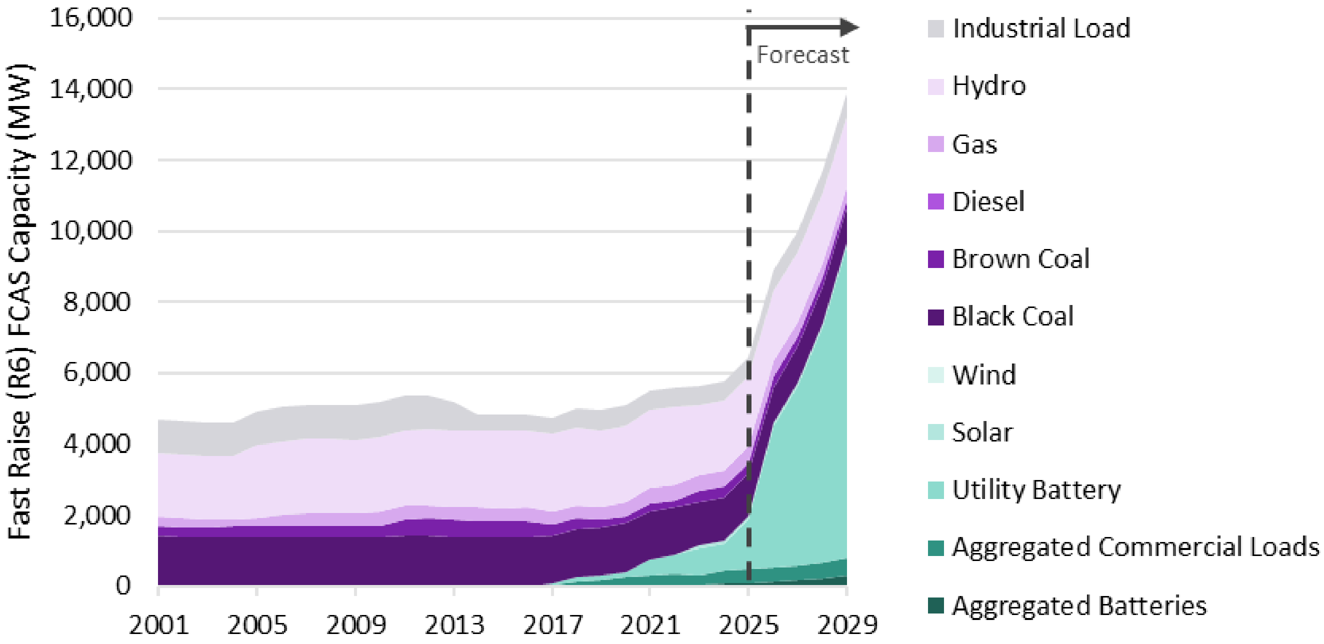
2.2.1 ISP projections

The ISP provides estimates of generation capacity by fuel type in the NEM until 2050. These projections can be used to estimate changes to FCAS availability due to the relevant anticipated retirements and additions. The ISP does not consider frequency control in detail, but AEMO provides the quantitative analysis below to estimate changes to FCAS availability due to anticipated retirements of existing FCAS supply and additions of generation likely to supply FCAS.

AEMO has modelled the likely changes in FCAS supply based on the ISP projections of generation capacity in the *Step Change* scenario. Figure 30 shows historical and forecast Fast Raise contingency FCAS registered capacity from 2001 to 2029 by fuel type, noting estimates from 2025 onwards are based on ISP projections of generation capacity.

Insight: The registered capacity of FCAS should increase significantly by 2029 primarily owing to the construction of many gigawatts of utility-scale battery units, supplemented by increasing quantities of aggregated batteries (VPPs), aggregated commercial loads and industrial load. Reductions in FCAS supply due to retiring synchronous generators are minimal in comparison.

Figure 30 Historical and estimated future Fast Raise contingency FCAS capacity by fuel type, stacked, 2001 to 2029



Notes:

- Forecast FCAS capacity reductions for retiring coal and gas generators have been assumed as the current registered FCAS capacity of these units and applied in the year of their latest announced expected retirement.

- Forecast FCAS capacity additions for utility-scale battery and aggregated battery sources have been calculated using the latest BESS guide to contingency FCAS registration[28] and assuming these units will be registered to their maximum FCAS potential which is equal to approximately 57% of their nameplate capacity. 10% of co-ordinated CER storage in the ISP Step Change pathway has been estimated as likely to register for FCAS as aggregated ancillary service facilities.
- *Demand side participation* from the ISP has been separated into the two categories of aggregated commercial loads and industrial loads as AEMO considers these sources of FCAS as distinct in FCAS characteristics – 50% of the growth in *demand side participation* in the ISP is considered here as likely to be registered for FCAS. This portion was split evenly between aggregated commercial loads and industrial loads.

2.2.2 Implications of the ISP projections for the available options to meet the requirements of frequency control

1. Reduction in provision of frequency control from synchronous resources.

The ISP anticipates the retirement of many synchronous generation units in the NEM. These units have historically provided a significant portion of FCAS in the NEM as seen in Figure 21 (in Section 1.2.3). The retirement of these units will decrease FCAS supply. The ISP does not anticipate significant additions of synchronous coal, gas or hydro units before 2029, although there are some significant additions expected around or after 2029, such as Snowy 2.0.

2. Increase in provision of frequency control from IBR units such as BESS, VRE and VPP resources.

The growth of FCAS supply from IBR technologies is anticipated to significantly alter the FCAS markets due to the capacity of these anticipated additions and the FCAS supply they will provide. Utility-scale BESS already capture a significant portion of the FCAS market and are likely to increase their market share as more plants are commissioned. It is further expected that VRE resources will increase their registered FCAS capacity as technical and operational difficulties are resolved. Aggregated FCAS resources have grown in the NEM since their first demonstration in 2019 and will continue to provide more FCAS.

3. Increase in provision of frequency control from demand-side response resources.

The range of ISP pathways envision increased opportunities for flexible consumer and industrial loads to contribute to the balancing of supply and demand. AEMO notes these resources typically are well-adapted to the FCAS market arrangements when configured to trip non-essential loads using switching controllers when system frequency reaches a pre-set threshold.

4. Increase in available synthetic inertia and some forms of synchronous inertia.

Synchronous inertia is likely to decrease as usually-on synchronous generation units are substituted by a mix of intermittent and firming units. However, there is increasing evidence that IBR units may be able to provide synthetic inertia. The growth of utility-scale BESS capacity in particular could provide a large quantity of usually-on synthetic inertia capability. Furthermore, the addition of synchronous condensers to meet system strength standards may increase system inertia if inertia-providing flywheels are included in procurement. This development would act to offset the loss of synchronous inertia from generating units.

[28] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/battery-energy-storage-system-requirements-for-contingency-fcas-registration.pdf?la=en.

2.3 Potential challenges to future frequency control in the NEM

This technical review paper has reviewed current frequency performance and work in progress to improve frequency control in the NEM. Additionally AEMO notes the following potential challenges to the frequency control framework as being possible focus areas for future investigations, which may inform future frequency control reviews and the General Power System Risk Review[29] (GPSRR).

2.3.1 Potential challenges to the frequency control framework in the NEM

Emerging operational conditions which may potentially challenge the frequency control framework include:

- Limited availability of frequency response, particularly Lower FCAS during minimum system load (MSL) periods, due to:
  - Synchronous generators being offline or at minimum load, and unable to reduce generation.
  - Energy storages charging or being full, and unable to increase consumption.
  - Semi-scheduled units being curtailed, and unable to reduce generation.
- Limited availability of frequency response in electrically islanded regions or subregions.
- Limited availability of frequency response from the aggregate BESS fleet due to state of charge being near 0% or 100%, and in aggregate providing one-way frequency control.
- Interconnector drift due to uneven primary frequency response across regions, or due to differences in forecast variable renewable energy outputs compared to actual outputs.
- Primary frequency response exceeding network or stability limitations, in particular when large quantities of fast frequency response (FFR) from BESS or similar units is provided in congested areas of the NEM power system.
- DER disconnect or cessation modes amplifying credible or non-credible contingency events.
- Single units or regions providing all FCAS without adequate consideration to system resilience.

Considerations for evolving existing tools and processes that support the frequency control framework include:

- Matters of regulation such as the appropriateness of the MASS and FCAS compliance program.
- Matters of registration such as the appropriate testing and validation policy for new technologies providing FCAS.

2.3.2 New perspectives on future frequency control in the NEM

Thinking beyond the immediate future, AEMO wishes to note the following observations which may challenge the fundamental concept of system frequency and its role in the NEM.

Relevance of system frequency as an indicator of supply and demand balance

Control of system frequency has been a fundamental requirement of managing the supply and demand balance of AC power systems since their first inception. There is a simple elegance in the control theory that ties the speed of synchronous

[29] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review.

generating units to the delivery of electrical energy to consumers. Even in 2025 this interplay between supply and demand remains a functional and desirable basis for control of a power system.

The arrival of IBR technologies, particularly large BESS units, in larger quantities may challenge this control arrangement. The range of ISP pathways described earlier anticipates approximately 20 gigawatts (GW) of utility-scale storage by the early 2030s, and it is likely this fleet will comprise mostly BESS units due to their technical maturity.

BESS technologies differ from synchronous units in their flexibility to tune their frequency-watt response rather than being dictated by physical plant factors. In practice, AEMO is limiting most BESS units to providing 100% of their charge or discharge capacity as frequency response when frequency reaches ±0.85 Hz outside their frequency deadband, which is typically 50±0.015 Hz due to the mandatory PFR reform. AEMO is currently satisfied with the balance struck between BESS response and system stability, which would be less assured if faster responses were allowed.

An estimate of aggregate NEM frequency response can be calculated from the arrangements described above. 20 GW of BESS in the NEM with 1.7% droop and ±0.015 Hz deadband applied will provide 3,176 MW of response by the time frequency reaches the NOFB threshold of 50±0.15 Hz, as demonstrated in Equation 1.

Equation 1 Droop calculation for 20 GW of BESS with 1.7% droop and ±0.015Hz deadband

$$Frequency\ Response = \frac{100}{Droop\ \%} \times \frac{\Delta\ Frequency}{50} \times BESS\ Capacity$$

$$= \frac{100}{1.7} \times \frac{0.135}{50} \times 20{,}000\ MW\ = 3176\ MW$$

A similar calculation shows the same BESS fleet would provide 235 MW for every 0.01 Hz beyond their ±0.015 Hz frequency deadband. Sudden changes in the supply-demand balance of the NEM rarely exceed 700-800 MW at present, as this corresponds to the sizes of the largest generating contingencies in the NEM.

These calculations suggest that the largest credible generation contingencies will move system frequency by approximately ±0.03 Hz. There is a need to consider RoCoF at this point, as BESS response is not instantaneous but rather delayed by measurement and control software. But if the NEM can maintain an adequate amount of inertia from synchronous and synthetic sources then frequency may not move further than the above amount during normal system conditions.

It is unclear whether the design of most existing frequency control arrangements, such as contingency and regulation FCAS, will remain relevant as these arrangements are predicated on system frequency providing an unambiguous signal of supply and demand imbalance to be corrected by unit response. The instantaneous supply and demand imbalance may be better understood by calculating the amount by which units providing frequency response are off-target and incorporating this quantity into the current control arrangements as a quantity to be minimised. Further analysis of the impact and mitigation of these considerations will be essential as the NEM power system moves beyond well-understood power system dynamics.

Priority action

- AEMO will monitor and review the aggregate generator frequency response and consider how this measure can be used in conjunction with system frequency as a control signal.

  Aggregate generator frequency response represents a part of the supply demand imbalance that is not evident in the system frequency, and system frequency may not be adequately controlled in the future without accounting for it.

2.4 What may need to change?

AEMO proposes the list of priority actions and recommendations for further consideration in the Executive Summary to mitigate existing and emerging challenges concerning frequency control in the NEM power system.

2.5 What is the likely end-state of the NEM system of frequency control?

The purpose of this Technical Review is to explore the current and likely adequacy of frequency control arrangements in the NEM across the range of ISP pathways. The energy transition will challenge conventional practices of electricity supply and power system control. The term *transition* suggests an end-state will be reached. It is natural to consider the likely end-state of the NEM system of frequency control across the range of ISP pathways after considering the discussion above.

While some risks have been identified, there is room for optimism from the considerations in this Technical Review and related works. An outline of the future NEM system of frequency control could reasonably expect:

- Frequency control to be provided by a spectrum of resources that may alternate regularly between synchronous resources and non-synchronous resources.
- Frequency control risks that grow in size, or likelihood, to be managed using larger quantities of existing frequency control arrangements.
- A very large latent frequency control capability to be available from new resources, which will assist to resolve many of the challenges of transitioning to a system based on VRE resources for bulk energy supply.
- Frequency control procurement to continue via transparent market mechanisms where practical owing to the excellent match between control capability and control requirements available in established and emerging frequency control resources.