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Essential System Services Framework Review

Consultation Paper
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Abbreviations

Term	Definition
ACE	Area Control Error
AEMO	Australian Energy Market Operator
AGC	Automatic Generator Control
BESS	Battery Energy Storage Systems
DER	Distributed Energy Resources
DFCM	Dynamic Frequency Control Model
DPV	Distributed Photovoltaics
EPWA	Energy Policy WA
ERA	Economic Regulation Authority
ESS	Essential System Services
ESSFRWG	ESS Framework Review Woking Group
ESM	Electricity System and Market (Rules)
ESR	Electric Storage Resources
DPV	Distributed Photovoltaic
FCESS	Frequency Co-optimised Essential System Services
FOS	Frequency Operating Standard
MAC	Market Advisory Committee
MPFR	Mandatory Primary Frequency Response
NCESS	Non-Co-optimised Essential System Services
NEM	National Electricity Market
PV	Solar Photovoltaics
PFR	Primary Frequency Response
RoCoF	Rate of Change of Frequency
RCS	Rate of Change of Frequency Control Service
RoCoF Safe Limit	Rate of Change of Frequency Safe Limit
RFTS	Real Time Frequency Stability (Tool)
RBM	Regulation Baseline Model
RCM	Reserve Capacity Mechanism
SCADA	Supervisory Control and Data Acquisition
SCED	Security Constrained Economic Dispatch
SEO	State Electricity Objective
SESSM	Supplementary Essential System Service Mechanism
SWIS	South West Interconnected System
UFLS	Under Frequency Load Shedding

Term	Definition
WEM	Wholesale Electricity Market
WEMDE	Wholesale Electricity Market Dispatch Engine

Executive summary/Overview

The Coordinator of Energy (Coordinator) is required by Section 3.15 of the Electricity System and Market (ESM) Rules to undertake a review of the Essential System Services (ESS) Process and Standards (the Review) within two and a half years of the New Wholesale Electricity Markert (WEM) Commencement Day (1 October 2023).

The Coordinator commenced a review of the ESS Framework in 2024, incorporating a review of:

- ESS Process and Standards as required by Section 3.15 of the ESM Rules; and
- Supplementary Essential Systems Services Procurement Mechanism (SESSM).[1]

The focus of the Review is on whether the ESS Standards and Requirements are consistent with the Western Australian (WA) State Electricity Objective (SEO). This includes determining whether the ESS requirements in the WEM are set at their most efficient level and whether the ESS quantities that are dispatched to meet those requirements are being efficiently and effectively procured and scheduled, while maintaining security and reliability of supply at the lowest cost to consumers.

The Market Advisory Committee (MAC) constituted a MAC Working Group to support the Review, the ESS Framework Review Working Group (ESSFRWG).

More information on the Review is available from the Energy Policy WA (EPWA) website, including the Scope of Work for the Review, the Terms of Reference for the ESSFRWG, papers for the ESSFRWG and relevant MAC meetings, and detailed minutes for each meeting held throughout the progression of the review.

Proposed Review Outcomes and Rationale

Table 1: Proposed Outcomes and Rationale

Proposed Outcomes	Rationale
Transparency of process	
Proposal 1 AEMO to update and publish the technical and operational guidelines relating to FCESS quantification and dispatch processes: • ESS Quantities WEM Procedure; • Dynamic Frequency Control Model (DFCM) process; • Real Time Frequency Stability (RTFS) tool process; and • Supplementary ESS Mechanism (SESSM) documentation.	ESM Rule changes have created a backlog of documentation to be developed by AEMO, which consequently has impacted publication dates of critical processes and WEM Procedures. In many cases documentation was either inadequate or non-existent, making it: • difficult for Market Participants to understand the processes; • challenging for AEMO to communicate why certain actions are needed; and • challenging for the Coordinator to review the effectiveness of the market. Assessing whether ESS quantities are set at their most efficient level, and whether the ESS quantities that are dispatched to meet those requirements are being

[1] The SESSM review is being carried out under Clause 2.2D.1(h), which confers the function on the Coordinator to consider and, in consultation with the Market Advisory Committee, progress the evolution and development of the WEM and the ESM Rules

Proposed Outcomes	Rationale
	efficiently and effectively procured and scheduled, requires transparent and complete methodology documentation. The Review has found that there is a there is a lack of transparency around the processes and methodology for setting ESS requirements in the WEM as there is insufficient documentation publicly available on: • how AEMO determines the ESS quantities and the DFCM methodologies; • RTFS tool influence on dispatch; • the process for increasing Regulation Raise and Regulation Lower; and • SESSM related documentation that describes how regular FCESS shortfalls are to be effectively and efficiently addressed. There is no available documentation on the RTFS tool's role in operational decision-making processes. Documentation that explains the role of the RFTS tool and how it is used in real time to monitor system security and determine whether, for example, additional RCS is needed above what WEM Dispatch Engine (WEMDE) has determined, is required. This information should be included in either in ESS Quantities WEM Procedure or the Dispatch Algorithm Formulation WEM Procedure, whichever AEMO determines to be the most appropriate.
Proposal 2 AEMO to review the inputs, parameters and assumptions for the DFCM and test whether they should be updated to reflect current system conditions and drive relevant and correct outputs. .	The DFCM simulates frequency using a combination of real time inputs and generic empirically derived parameters. It is a key input to the WEMDE solution for dispatch of FCESS, yet many of the DFCM input, assumptions and variables are based on potentially outdated information or inaccurate assumptions. This creates difficulty in assessing whether the amount of ESS scheduled is set at an efficient level. The Review has identified that there is a need to better understand the process for defining the inputs of the DFCM: • empirical selection to match physical system observations are without documentation or clear explanation; and • assumption and inputs, such as load relief, governor droop response and deadband, and distributed inverter ramping and disconnection thresholds are based on potentially outdated information or inaccurate assumption.

Proposed Outcomes	Rationale
	The role of the DFCM is not well described in terms of the inputs, assumptions and parameters that are used in the model and the outputs that go into the look-up tables. Further clarity is required on how AEMO determines the parameters used in the look-up table produced by the DFCM. The impact of AEMO changing a particular parameter is not evident because the assumptions, inputs and paraments that are going into the model are not clearly articulated. There is uncertainty as to what impact updates to the DFCM are having and what the differences between versions are. When updates to the DFCM occur the effect of changing a particular parameter should be made clear. How the look-up table feeds into WEMDE and how WEMDE uses that information to work out the ESS requirements is unclear. Information on how the look-up table that is produced by the DFCM, is used in WEMDE is required. For example, there needs to be a clear explanation of exactly what the DFCM produces (e.g. what each row of the output look-up table contains) and how this table is then used by WEMDE for Contingency Raise and Lower and RRCS dispatch purposes.
Increase in the RoCoF Safe Limit	
Proposal 3[2] Increase the RoCoF Safe Limit from 0.25 Hz per 0.5 seconds to 0.75 Hz per second to reduce the need for AEMO interventions.[3]	Between 20 November 2024 and 29 May 2025, there have been a total of 100 interventions by AEMO related to RoCoF Control Service (RCS) shortfalls. These interventions were in the form of directing synchronous generators to commit and additional System Inertia to: • prevent breaches in the RoCoF Safe Limit; or • ensure that following a Credible Contingency Event the system landed in a secure and satisfactory operating state. On 62 days AEMO directed one or more units under clause 7.7.3. of the ESM Rules. While such interventions were necessary to maintain the RoCoF Safe Limit of 0.25 Hz per 0.5 seconds, it should be considered whether this could be lifted in the

[2] RoCoF is commonly defined in Hz per second. However, the critical period occurs during the first 500 ms when frequency response is predominantly inertial as synchronous machines cannot increase their active power output instantly. Hence, while expressing RoCoF in Hz per second, AEMO also defines that this RoCoF rate will apply to the first 500 ms.

[3] AEMO has conducted preliminary analysis that suggests an increase to 0.75 Hz per second over the first 500 ms may be feasible, subject to consultation with industry. More details of this work conducted by the system operator is presented in Section 3.3.

Proposed Outcomes	Rationale
	WEM to be more aligned with other similar modern power systems that establish RoCoF Safe Limits of 1 Hz per second. The RoCoF Safe Limit was set conservatively ahead of market start in the WEM with the intent to reassess it once AEMO had gained sufficient real time market operation experience. Increasing the RoCoF Safe Limit from 0.5 Hz per second to 0.75 Hz per second could reduce the need for AEMO interventions and associated Energy Uplift Payments by allowing higher RoCoF events without compromising system security. AEMO analysis and simulations showed little change in the required Contingency Reserves under present dispatch conditions and indicate potential for greater operational flexibility and cost savings, by allowing generators with low Facility Performance Factors to participate in RCS at lower system inertia levels. RoCoF costs have decreased since market start. The proposed increase in the RoCoF Safe Limit will continue to reduce these costs as the need for manual interventions lessen and Energy Uplift Payments are avoided. As a result, the overall costs that are distributed to Market Participants will be lower.
Further investigation proposed	
Proposal 4 AEMO to implement a monitoring program over a twelve-month period to track the amount of headroom and footroom available from unaccredited Facilities or non-dispatched FCESS Facilities to better quantify mandatory Primary Frequency Response (MPFR) availability to assess the level of Contingency Reserve Raise and Lower that could be provided from the inclusion of MPFR.	All online generators must be frequency responsive within a narrow frequency deadband under section A12.6.1.8 of the ESM Rules. A review of market data suggests that the positive active power headroom of synchronous generators online that are not dispatched for Contingency Reserve Raise, can often be greater than the Largest Credible Supply Contingency. Clause 7.5.11(c) of the ESM Rules requires AEMO to determine the Contingency Reserve Raise Offset and the Contingency Reserve Lower Offset while having regard for droop response from synchronised registered Facilities. For example, MPFR provided by online synchronous generation should be considered when determining the Contingency Reserve Raise required to arrest a decline in frequency following the Largest Credible Supply Contingency. To establish to what extent MPFR could offset Contingency Reserve Raise and Contingency Reserve Lower requirements it is proposed that: • AEMO establish a monitoring program that tracks the performance factor adjusted MPFR available from online and non-Contingency Reserve Raise

Proposed Outcomes	Rationale
	dispatched facilities (i.e. all Energy Producing Systems) throughout the year (and time of day). • On conclusion of the monitoring program AEMO and the Coordinator are to review outcomes and, if warranted, recommend appropriate changes to Contingency Reserve Raise and Lower procurement.
Proposal 5 Assess the suitability of synthetic inertia (RCS) from Battery Energy Storage Systems (BESS) in complementing synchronous Inertia from rotating machines, and consider potential barriers and suitable incentivisation for grid-forming BESS to provide such services.	Synthetic Inertia mimics synchronous inertia and could potentially reduce RCS and AEMO directions. AEMO Market Advisories[4] state that in the six months from 20 November 2024 to 19 April 2025 AEMO issued a total of 90 directions over 56 separate days to address either RCS shortfalls or persistent predictions of RoCoF Safe Limit violations, ie. to manage instances of insufficient System Inertia. Although Market Advisories & Notices are published to provide timely alerts on system conditions, outages or market anomalies, they are lacking information. For example, they do not provide detail regarding the cause of RoCoF shortfalls and only note that one or more incidents occurred on the day and particular synchronous generators were dispatched to ensure system security. Given the number of directions and the expected growth in grid forming invertors there may be benefit to considering this in the WEM. Up to a third of Capacity Credits may be allocated to Electric Storage Resources capable of providing Contingency Reserve Raise and synthetic Inertia in the future. The least cost provision of Contingency Reserve needs to be considered as the SEO requires system security to be balanced with cost and the environment. AEMO requires a fit for purpose mechanism to procure Inertia as synchronous plant retire. There is currently limited consideration of the opportunities provided by new technologies such as the synthetic Inertia from grid-forming BESS can provide in the WEM and how they can be accommodated within the current market design. The outcome of the case study was to demonstrate that synthetic Inertia is a cheaper addition to the system than, for example, synchronous condensers. Technical verification and identification of appropriate incentivisation mechanisms are necessary before

[4] AEMO Market Data

Proposed Outcomes	Rationale
	considering any implementation. This Review supports further analysis and assessment by AEMO to: (a) assess the suitability of synthetic inertia (RCS) from BESS in complementing synchronous inertia from rotating machines, and (b) consider potential barriers and suitable incentivisation for grid-forming BESS to provide such services.

1. Introduction

The Coordinator of Energy (Coordinator) is required by Section 3.15 of the Electricity System and Market (ESM) Rules to undertake a review of the Essential System Services (ESS) Process and Standards (the Review) within two and a half years of the New Wholesale Electricity Market (WEM) Commencement Day on 1 October 2023.

The Coordinator, in consultation with the Market Advisory Committee (MAC) commenced a review of the ESS Framework (the Review) in 2024, incorporating a review of the:

- ESS Process and Standards as required by Section 3.15 of the ESM Rules; and
- Supplementary Essential Systems Services Procurement Mechanism (SESSM).

The purpose of this Review is to ensure the framework for Frequency Co-optimised Essential System Services (FCESS) is operating efficiently to ensure power system security and reliability can be maintained at the lowest cost to consumers.

1.1 Guiding principles

The Coordinator, in consultation with the MAC, established overarching guiding principles for the Review that any of the outcomes should:

- be consistent with the SEO;
- be cost-effective, simple, flexible and sustainable;
- enable the orderly transition to a low emissions energy system characterised by higher levels of intermittent and distributed generation;
- allocate risks and responsibility to those who can manage them best;
- provide investment signals and technical capability requirements that support the reliable and secure operation of the power system; and
- ensure the FCESS providers are not over or under compensated for their participation in ESS markets or the SESSM.

1.2 Purpose of the ESS Framework Review

The focus of the Review is on whether the ESS Standards and requirements are consistent with the State Electricity Objective (SEO). Procurement of ESS must be in the long-term interest of consumers in relation to security, cost, and the environment.

Setting the ESS requirements at the right level is important for both security and efficiency. Excessive ESS procurement maintains security, but at higher cost to consumers, while insufficient quantities may reduce costs to consumers, but risk security of supply.

Section 3.15 of the ESM requires a statutory review of the ESS Standards and the basis for setting the ESS requirements.[5] The Review must meet the requirements of clause 3.15.1C of the ESM Rules.

To meet the requirements of the Review, a combination of technical and economic analysis, including a series of case studies, were undertaken to assess the operation of the current ESS processes.

1.3 Stakeholder consultation

Stakeholder feedback is invited on the Proposals, as outlined in this Consultation Paper. Submissions can be emailed to: energymarkets@deed.wa.gov.au. Any submissions received will be made publicly available on www.energy.wa.gov.au, unless requested otherwise. The consultation period closes at 5:00pm (AWST) on 15 December 2025. Late submissions may not be considered

2. Background

2.1 Wholesale Electricity Market Reform

The energy market in the South West Interconnected System (SWIS) is undergoing a major transformation in the move to net zero emissions energy sector. Changes in large scale grid connected technologies and consumer demand patterns, and the monumental growth in distributed energy resources (DER), have led to significant changes in the way energy is produced and consumed.

Significant modifications were required to the design of the WEM to meet these challenges which required significant and ongoing reform of the WEM, and the Reserve Capacity Mechanism (RCM) including:

- the introduction of the Real-Time Market, to facilitate the co-optimised dispatch of energy and FCESS at the lowest cost;
- the implementation of a Security-Constrained Economic Dispatch (SCED) to improve the operational efficiency of the energy and FCESS markets in the WEM, in the context of the introduction of a constrained access framework for Western Power's network;
- the implementation of a constrained network access model, which removed the obligation for new entrants to fund network augmentation and allowed the dispatch of electricity from the cheapest available resources, while respecting network limitations;
- a new framework for integrating storage resources, including new arrangements for the registration and participation of storage facilities that enable their certification to provide capacity and accreditation to compete in the FCESS markets.

2.2 Essential System Services

As the transition to a low emissions energy system characterised by increasing levels of intermittent and distributed generation continues, ESS become increasingly important to maintain power system security and reliability.

[5] There are three types of ESS in the WEM, however only the FCESSS are being considered as part of this Review.

ESS are vital for ensuring the security and reliability of the energy supply, thereby supporting the energy market. ESS are used to regulate frequency and respond to contingency events within the power system. AEMO must procure sufficient ESS to meet the Frequency Operating Standard (FOS).

The new WEM co-optimises energy and ESS in the dispatch processes. This co-optimisation means the dispatch engine simultaneously considers bids and availability for energy and ESS to determine the most cost-efficient dispatch solution while maintaining power system security and reliability.

FCESS are acquired in the Real-Time Market from accredited Facilities and include:

- Regulation which is the service, measured in megawatts (MW) of response capability, which frequently adjusts the Injection or Withdrawal of a Facility. It is provided by Facilities capable of receiving Automatic Generator Control[6] (AGC) signals from AEMO to assist in maintaining the SWIS Frequency according to the FOS. The Regulation service has both a raise and lower component:
  - Regulation Raise, that operates to raise the SWIS Frequency; and
  - Regulation Lower, that operates to lower the SWIS Frequency.
- Contingency Reserve which is the service, measured in MW, of holding response capability associated with a Facility in reserve so that the relevant Facility can rapidly adjust Injection or Withdrawal in order to assist in maintaining the SWIS Frequency according to the FOS after a Contingency Event. Contingency Reserve has both a raise and lower component:
  - Contingency Reserve Raise, that enables a Facility to adjust Injection or Withdrawal to raise the SWIS Frequency; and
  - Contingency Reserve Lower, that enables a Facility to adjust Injection or Withdrawal to lower the SWIS Frequency.
- Rate of Change of Frequency (RoCoF) Control Service (RoCoF Control Service (RCS)), measured in MWs, which provides Inertia to provide instantaneous response to slow down the rate of change of the SWIS Frequency. The RCS has two functions:
  - to ensure that the RoCoF is restricted to below a certain maximum level; and
  - to ensure that minimum Frequency requirements are maintained by potentially allowing a trade-off between the amount of reserve required and the amount of Inertia on the power system.

Market Participants with Facilities which meet the performance requirements for an FCESS can seek accreditation and subsequently participate in any FCESS market for which their Facility is accredited. It is currently not mandatory for any Facility to accredit for FCESS or participate in the FCESS markets.

If insufficient FCESS is projected to be available in the Real-Time Market, AEMO can trigger longer-term procurement of FCESS through the SESSM, which can also be used to ensure existing accredited capacity is made available to the market when it is required.

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[6] The AGC is used for energy and FCESS dispatch and monitoring. It is a slow closed loop control that seeks to apply small changes in generator output to balance frequency at 50 Hz during normal system operation.

3. Technical Assessment

The WEM requires secure and stable system frequency to ensure the continuous delivery of electricity to consumers. As specified in the ESM Rules, the FOS:

- define the acceptable frequency ranges for the SWIS under normal and contingency conditions;
- set the performance targets for maintaining the system frequency close to 50 Hz during normal operations; and
- define the acceptable frequency bounds and recovery times following disturbances.

Maintaining frequency within the FOS is essential to protect system integrity, equipment, and avoid blackouts. AEMO procures and co-optimises ESS to meet these standards and is required to publish the WEM Procedure: ESS Quantities, detailing how much of each service is needed.

The key objective of this Review is to confirm that the ESS Standards and the basis for setting ESS requirements are set appropriately for the WEM. This requires an assessment of whether:

- the FOS is maintained by the existing standards and processes; and
- if so, the standards are not overly conservative and imposing unnecessary costs on the market (and therefore consumers).

3.1 Regulation

Regulation services play a critical role in managing minor and continuous frequency deviations within the Normal Operating Frequency Band (49.8–50.2 Hz) of the SWIS, enabling the system to respond to small mismatches between supply and demand under normal operating conditions.

The Regulation quantities set out in Table 2 below, were determined by AEMO using a statistical model, the Regulation Baseline Model[7] (RBM), prior to the New WEM Commencement Day. There is limited information available regarding the RBM.

Table 2: Principles for setting the Regulation requirements

Period	Clear or largely clear weather conditions	Otherwise (incl. cloudy conditions)
Daytime (05:30 – 20:30)	80 MW	110 MW
Nighttime (20:30 – 05:30)	65 MW	65 MW

Operational dispatch requirements for Regulation Raise and Regulation Lower derived from the RBM are generally set twice a day by the AEMO control room operators to match the expected weather conditions. In addition to this, AEMO may intervene and procure additional Regulation services if a period of high volatility is expected, such as a significant cloud movement that could create high intermittency of Distributed Photovoltaic (DPV).

RBM inputs include predictions of solar irradiance and cloud cover (variable solar output), wind speed (variable wind output), operational demand forecast (variable DPV production) and total demand at the transmission level), time of day/day of week/season adjustments, and other errors and uncertainties.

[7] AEMO WEM Procedure: Essential System Service Quantities

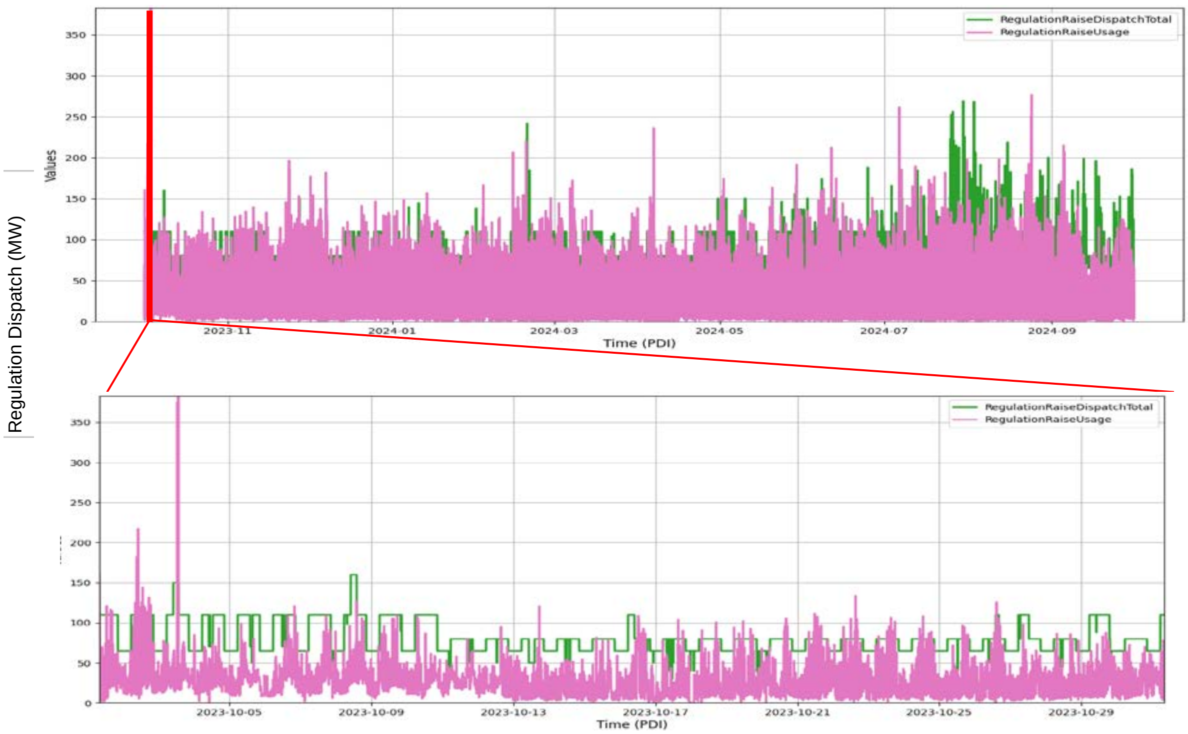

Figure 1: Utilisation of Regulation Raise FCESS in the first year of the new market arrangements

The Regulation requirements are based on the experience of the AEMO control room operators, as well as statistical analysis**.**

Dispatch of Regulation Raise to correct frequency changes is illustrated below in Figure 1. The set quantities procured through WEMDE are dispatched by AGC, including any additional services procured by the AEMO control room operator. While not shown, the Regulation Lower quantities and usage are similar to those illustrated for Regulation Raise.

System performance in the Normal Operating Frequency Band is largely dependent on the adequacy of Regulation services procured and dispatched by AEMO. However, it is anticipated that the presence of Primary Frequency Response (PFR), as mandated by the ESM Rules, is also having a positive influence on the performance of frequency during normal system operation. The effectiveness of mandatory PFR (MPFR) to maintain the Normal Operating Frequency Band is further described in Section 3.5.

Two years of SCADA frequency data, from November 2022 to November 2024 were analysed and the assessed data is shown below in Figure 2, including boundaries marking the Normal Operating Frequency Band (49.8–50.2 Hz).

While Figure 2 below, does shows frequency sporadically exceeding the upper and lower operating bands, these excursions do not constitute non-compliance with the FOS. Infrequent or momentary deviations outside the Normal Operating Frequency Band are allowed, provided that the system maintains frequency within this band for at least 99% of the time over any rolling 30-day period

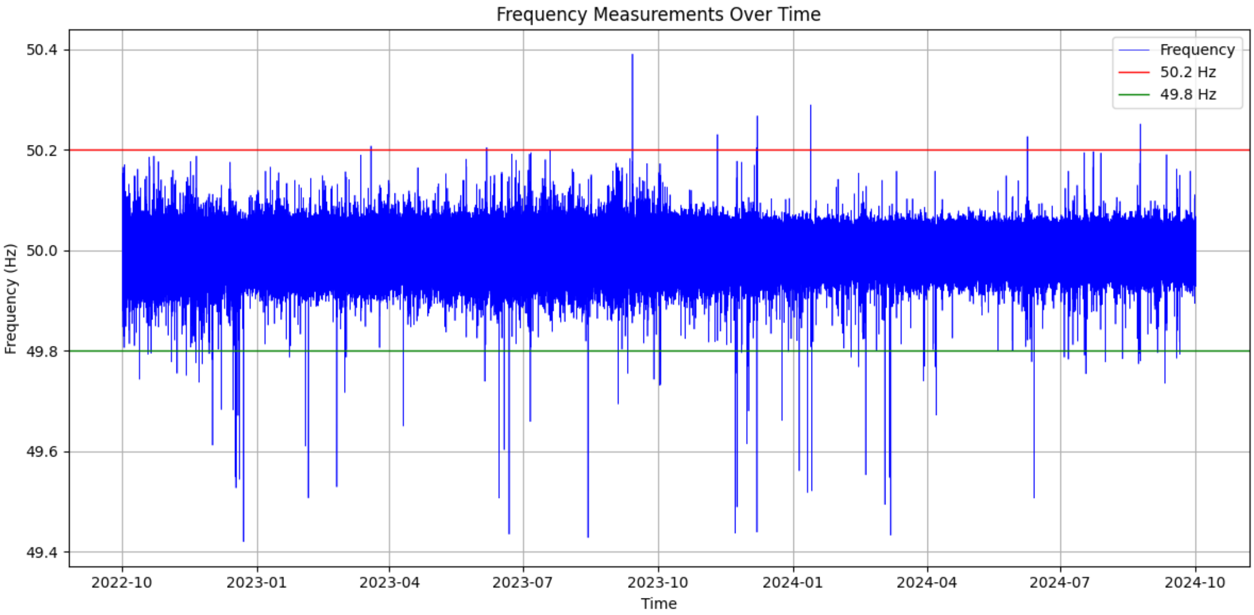

Figure 2: WEM frequency performance from 2022 - 2024

The compliance metric for maintaining frequency within the Normal Operating Frequency Band is illustrated below in Figure 3, which shows that the percentage of time the frequency remained within the Normal Operating Frequency Band. As shown, this percentage consistently exceeds the 99% threshold required by the FOS.[8]

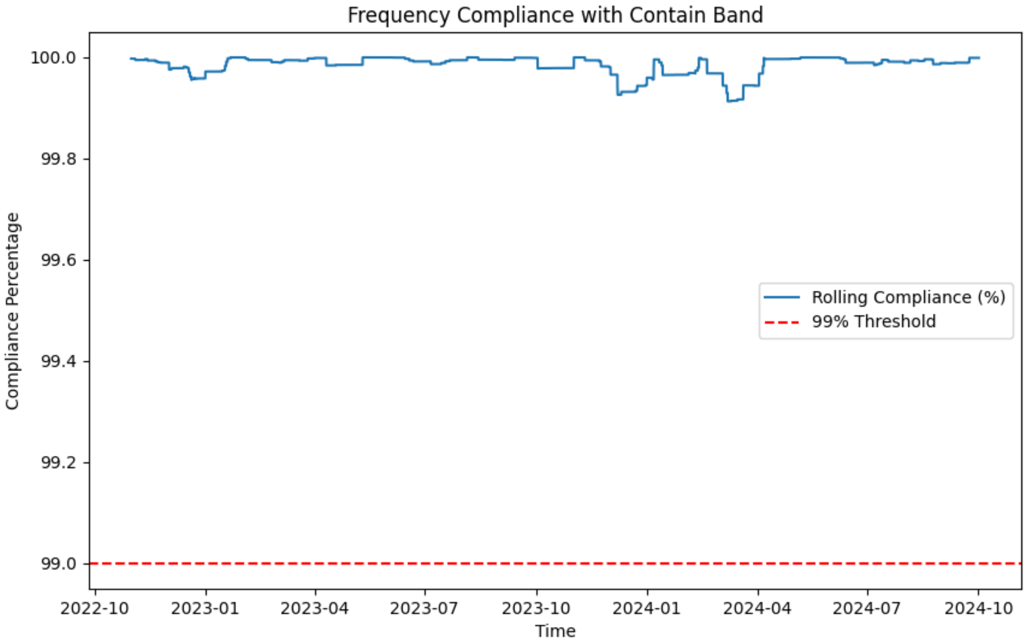

Figure 3: Rolling average containment of frequency in the normal operating band

[8] Frequency does exceed the Normal Operating Frequency Excursion Band of 49.7 and 50.3 Hz in some instances but it is contained and returned to within the Normal Operating Frequency Band within five minutes in all instances, as required by the FOS.

This level of performance implies a very narrow frequency distribution, indicative of a very tight frequency management.

While the FOS has been met, there are further observations that can be made based on the frequency performance assessment (see section 5). These observations provide a basis for the metrics to be used for ongoing monitoring of ESS:

1. Normal operation frequency performance (Figure 3) is significantly higher than the minimum FOS requirement of 99% (Figure 2), with the recorded 30-day rolling average greater than 99.9%. This could imply that the level of Regulation being procured is excessive. Alternatively, it may also imply that MPFR supplied by synchronised generating Facilities is contributing to frequency corrections. Further analysis of future frequency measurements should be carried out to establish potential reasons for such high levels of performance.
2. There appear to be periods of heightened volatility in frequency that result in more breaches of the Normal Operating Frequency Band than other times (Figure 2) e.g., summer 2024/25. There may be benefits to considering whether the 30-day rolling window of measurement should be reduced, to more precisely show Normal Operating Frequency Band violations, i.e. increased granularity of frequency performance results. This could highlight if there is need for additional Regulation quantities during particular times of the day or year. Monitoring of future frequency performance is required to clarify this.
3. Usage of the set Regulation quantities appears on average to be very high, i.e. the amount of Regulation enabled by WEMDE is often being fully dispatched during a Dispatch Interval (Figure 1). As the dispatch of Regulation services is automated through the AGC, a review of the AGC parameters could provide more insight as to why Regulation is heavily used when frequency appears to be well within the Normal Operating Frequency Band.
4. Regulation procurement often exceeds the set quantities outlined in the ESS quantification for time of day and atmospheric conditions. This is due to AEMO operator intervention or operational forecasting action required during times when higher volatility in the supply-demand balance is expected, e.g. high DPV volatility due to increasing cloud movement. The regular occurrence of this need for correction highlights a need for review of the RBM.

3.2 Contingency Reserves and RoCoF Control Services

Contingency Reserve plays a critical role in managing SWIS frequency following a contingency event. It helps arrest deviations, stabilize the system and restore frequency by utilizing Facilities that maintain reserve capacity, enabling rapid adjustments in output or consumption in response to significant frequency changes. The Credible Contingency Events that AEMO's schedules and dispatches against are:

- the largest single generating facility, or the loss of a transmission element that creates a loss of generation greater than the single largest Facility; and
- the largest single load, or the loss of a transmission element that creates a loss of load greater than the single largest load.

AEMO uses the Dynamic Frequency Control Model (DFCM) [9] to simulate system frequency response for a range of operating conditions called ESS System Configurations.

[9] AEMO | Contingency Reserve Quantities

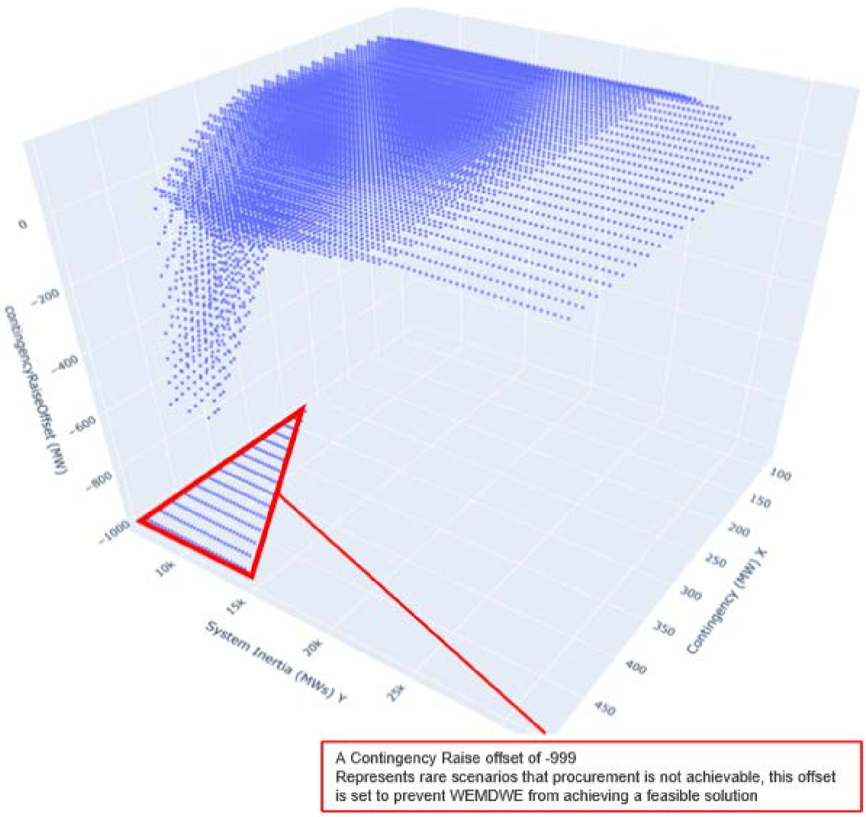

Figure 4: DFCM look-up table

For each configuration, the DFCM determines[10] the amount of:

- Contingency Reserve Raise (for supply contingencies); and
- RoCoF Control Service or RCS (inertia-equivalent response).

The DFCM is an offline model that takes inputs ahead of time and creates outputs in the form a look-up table (Figure 4) that links operating scenarios to required service quantities. The DFCM look-up table is then used in real-time dispatch by WEMDE.

A configuration is deemed non-securable if no feasible combination of services can keep the system frequency within the secure band.

To integrate DFCM results into the real-time dispatch algorithm, AEMO converts outputs into parameters such as:

- Contingency Raise Offsets;
- Contingency Lower Offset; and
- Facility Performance Factors.

The DFCM is a single-frequency model that simulates frequency using a combination of real time inputs and generic empirically derived parameters. The DFCM is used to define the Contingency Raise Offset that goes into WEMDE for the purpose of dispatch, whereas the RTFS Tool is used by the control room to verify system security and is the basis for decisions by the AEMO control

[10] The DFCM does not determine Contingency Reserve Lower services for load contingencies. These quantities are set by AEMO in a manner related to the Largest Credible Load Contingency with a Speed Factor of one.

room to intervene and direct when more Contingency Raise is required. Both processes look to achieve the same thing but appear to have different inputs.

Empirical selection to match physical system observations are without documentation or clear explanation, assumption and inputs, such as load relief, governor droop response and deadband, and distributed inverter ramping and disconnection thresholds are based on potentially outdated information or inaccurate assumptions.

Current process documentation as well as changes to the DFCM versions published by AEMO are also limited in detail as to how the version changes will affect the DFCM outcomes.

The amount of Contingency Reserve a Facility can provide in real time is adjusted by its Facility Performance Factor[11] (Performance Factor). If it is slower than the reference scenario, its ability to provide services will be adjusted by a proportional amount.

- Performance Factors are derived from the DFCM using the Facility Speed Factor (Speed Factor) of each FCESS Facility.
- Speed Factors represent the time in seconds for a facility to reach a specific Primary Frequency Response (PFR) output and are determined for each Facility as part of the FCESS accreditation process.

Performance Factors scale between zero and one, and are a measure of how effective a Facility is at delivering contingency response relative to a Largest Credible Supply Contingency. These parameters are then used in WEMDE to co-optimise energy and FCESS dispatch.

Facilities with fast or slow Speed Factors can potentially provide necessary Contingency Reserve Raise. However, if a configuration with a particular Contingency Reserve Raise provider is deemed Non-Securable (i.e. no secure outcome is possible for any reserve quantity as illustrated by the red bounded point in Figure 4), the Performance Factor for that provider is set to zero.

The Performance Factor of an FCESS provider can change from one Dispatch Interval to the next, subject to the prevailing system conditions. If a generator is unable to support a contingency and meet the RoCoF Safe Limit and arrest frequency decline prior to reaching the Credible Contingency Event Frequency Band a Performance Factor of zero is applied, reflecting a DFCM outcome without a solution.

This effectively creates a conservative WEMDE outcome for certain system conditions, as these generators may not provide all their Contingency Reserve Raise output quickly enough, but they may still provide a fraction of it and still contribute to frequency stability.

In the WEM, Inertia is procured in the form of RoCoF Control Service. RoCoF is a reflection of the size of an energy imbalance that is present in an electrical network following a system disturbance, such as a loss of generation or load, and must be managed by AEMO.

The higher the RoCoF experienced subsequent to a disturbance, the faster the activation of reserves must be to prevent frequency from falling or rising rapidly and breaching the Credible Contingency Event Frequency Band.

While the concept of virtual synchronous Inertia is receiving attention, the provision of such services from Battery Energy Storage Systems (BESS) cannot be accommodated within the current design of the WEM. Currently the WEM relies on rotational Inertia from synchronous generators to maintain the RoCoF Safe Limit during the inertial response time. If a shortfall in RCS is identified AEMO can direct synchronous generation to ensure that the RoCoF Safe Limit is not exceeded.

To assess the system's frequency performance following Credible Contingency Events, high-resolution frequency measurements captured by high-speed data recording equipment for six

[11] AEMO FCESS Accreditation

significant events in the SWIS were reviewed. The events were selected based on their potential to cause noticeable frequency disturbances and, for each event, the frequency nadir and RoCoF were determined.[12] The details of these events are summarised below in Table 3.

Table 3: Recorded frequency disturbance events in the WEM pre- and post- New WEM

Time Of Event	Event	Recorded Frequency Nadir (Hz)	Calculated RoCoF (Hz per second)
27 July 2022	Trip of 340 MW of synchronous Generation	49.28	-0.29
13 September 2022	Multiple successive DPV fluctuations coinciding with incorrect generation dispatches	50.25 (09:29), 49.72 (10:52), 49.05 (11:58)	N/A
22 December 2022	NewGen Kwinana CCG1 tripped at 283 MW	49.49	-0.22
23 November 2023	NewGen Kwinana CCG1 tripped at 330 MW	49.40	-0.24
12 January 2024	330 kV Line Trip and Load Rejection	50.32	N/A
7 March 2024	Trip of Collie G1 unit at 300 MW	49.44	-0.22

In all six events observed, the frequency stabilised within the Credible Contingency Event Frequency Band as defined in the FOS.

- The largest recorded frequency excursion was a frequency nadir of 49.40 Hz, which remained within the acceptable limit for such events.
- The RoCoF did not exceed the RoCoF Safe Limit of 0.5 Hz per second (over the first 0.5 seconds), with the largest recorded value being -0.24 Hz per second (in the first 0.5 seconds).

These results indicate that the system response to Credible Contingency Events has remained compliant with the FOS and that procured FCESS have effectively managed frequency excursions and RoCoF within the RoCoF Safe Limit.

While the procurement of Contingency Reserves has to date achieved compliance with the FOS, the Review must also consider the efficiency of the procurement.

3.3 Key findings of the technical assessment

The observed and recorded performance of the WEM indicate that the technical requirements are being met and well above minimum requirements:

- 99% of the frequency during any rolling 30-day window must be inside the normal operating band, the data shows that 99.8% was achieved; and

[12] Due to limited disturbance recordings being available since 20 October 2023, as well as a comparison to system responses prior to New WEM Commencement Day, additional events have been included in the tabulated data. This includes generator trips and load fluctuations that occurred between July and December 2022.

- Utilisation appeared to be low at times, leading to the question of how Regulation Raise and Regulation Lower quantities are set, whether they should be reviewed again, and if the process to set quantities is appropriate.

Achieving compliance with the FOS was not possible through reliance on market based procurement of FCESS alone:

- to achieve compliance necessitated intervention by AEMO to procure additional RCS to manage the RoCoF Safe Limit, as reported in the AEMO Market Advisories.[13]

3.3.1 Transparency of processes

Transparency is a core principle underpinning the operation of the WEM in Western Australia. It ensures that Market Participants, the ERA, the Coordinator of Energy and the public have access to timely, accurate, and clear information about the market and power system operations. Transparency is provided through the market data portal and WEM data dashboard and through the publication of reports such as AEMO's Quarterly Energy Dynamics Reports[14] and WEM Electricity Statement of Opportunities.[15]

WEM Procedures are detailed, subordinate instruments that provide operational detail and practical guidance on how to implement and comply with the ESM Rules, and they are important as they describe the relationships between the technical parameters and how AEMO sets the ESS requirements.

ESM Rule changes have created a backlog of documentation to be developed by AEMO, which consequently has impacted publication dates of critical processes and WEM Procedures. In many cases documentation was either inadequate or non-existent, making it:

- difficult for Market Participants to understand the processes;
- challenging for AEMO to communicate why certain actions are needed;
- challenging for the Coordinator to review the effectiveness of the market.

Table 4 below lists several AEMO processes and documents that are required, but had not yet been published, or have been published but with limited insight into the processes they are meant to describe at the time of writing this paper.

[13] AEMO Market Advisories

[14] AEMO | Quarterly Energy Dynamics (QED)

[15] AEMO | WEM Electricity Statement of Opportunities

Table 4: Incomplete documentation

Process / Documentation	Unclear / Incomplete
WEM Procedure: ESS Quantities	Further clarity is required on how AEMO determines the parameters used in the look-up table produced by the DFCM. The role of the DFCM is not well described in terms of the inputs, assumptions and parameters that are used in the model and the outputs that go into the look-up table. There needs to be information on how the look-up table that is produced by the DFCM, is used in WEMDE. How the look-up table feeds into WEMDE and how WEMDE uses that information to work out the ESS requirements is unclear. For example: • detail on how AEMO determines the size of a Credible Contingency Event, e.g. how the additional MW relating to PV is being determined is missing. This is a significant step in determining Contingency Raise and Lower and RCS requirements, and so it should be clearly explained; and • it is unclear how RCS requirements are being determined, e.g. there is no mention of the role that the RTFS is playing. There needs to be a clear explanation of exactly what the DFCM produces (e.g. what each row of the output look-up table contains) and how this table is then used by WEMDE for Contingency Raise and Lower and RCS dispatch. This information should be included in either in ESS Quantities or the Dispatch Algorithm Formulation WEM Procedure, whichever AEMO determines to be the most appropriate.
DFCM versions and updates	The DFCM is an offline model that takes inputs ahead of time and creates look-up tables and quantities that specify Contingency Reserve Raise requirements. There is uncertainty as to what impact updates to the DFCM are having and what the differences between versions are. The impact of AEMO changing a particular parameter is not evident because the assumptions, inputs and paraments that are going into the model are not clearly articulated. When updates to the DFCM occur the effect of changing a particular parameter should be made clear.
Real Time Frequency Stability (RTFS) tool functionality and logic	The RFTS tool is used in real time by the AEMO control room operators to verify system security, and is the basis for decision by the AEMO control room to intervene and direct Facilities. The RFTS tool is checking in real time all of the things that can go wrong, modelling what is currently happening and will flag if there is a problem that requires intervention to keep the system safe.

Process / Documentation	Unclear / Incomplete
	However, there is no available documentation on the RTFS tool's operational role and decision-making process. Documentation that explains the role of the RFTS tool and how it is used in real time to monitor system security and determine whether, for example, additional RCS is needed above what WEMDE has determined, is required.
WEM Dispatch Engine & Co-Optimisation	There is no documentation on updates to the algorithm functionality or optimisation framework.
SESSM Service specification	There has not yet been a SESSM related documentation released that describes how regular FCESS shortfalls are to be effectively and efficiently addressed. Incomplete or unpublished procedures create a lack of process and specification transparency.
Market Advisories & Notices	Although Market Advisories & Notices are published to provide timely alerts on system conditions, outages or market anomalies, they are lacking information. For example, they do not provide detail regarding the cause of RoCoF shortfalls and only note that one or more incidents occurred on the day and particular synchronous generators were dispatched to ensure system security.

If the above information is not available to Market Participants, the Coordinator and the ERA, there is limited transparency in the way that FCESS are procured and dispatched, whether the procured quantities are sufficient or excessive, or whether the processes applied are efficient.

Proposal 1

AEMO to update and publish the technical and operational guidelines relating to FCESS quantification and dispatch processes: ESS Quantities WEM Procedure, DFCM process, RTFS process, and SESSM documentation.

Consultation question

Do stakeholders support the proposal for AEMO to update and publish these technical and operational documentation?

Do stakeholders consider there is additional documentation pertaining to the ESS requirements and processes that is missing or require review?

The DFCM was introduced as part of the WEM Reform program to support real-time frequency management in the SWIS. At a high level, it is an “offline” power system model that AEMO uses to pre-calculate the required contingency services for all plausible operating configurations and store secure results as a look-up table. AEMO uses the look-up table as an input to the Dispatch Algorithm, which will interpolate between the Secure Operating States to select the optimal configuration of Continency Reserves.[16]

The DFCM is a key input to the WEMDE solution for dispatch of FCESS, yet many of the DFCM input assumptions and variables, such as load relief, governor droop response and deadband, and

[16] ESS Quantities

distributed inverter disconnection thresholds are based on empirical data, or possibly outdated information.

Current process documentation as well as changes to the DFCM versions published by AEMO are also limited in detail as to how the version changes will affect the DFCM outcomes.

Both the DFCM and the RTFS tool processes look to achieve the same thing but appear to have different inputs and, if there is a discrepancy between WEMDE and the RFTS tool, the control room operator will intervene. AEMO is currently working on changes to improve the DFCM and how WEMDE processes the outputs for the DFCM. This should see a reduction in the occurrences of discrepancies between the two which will lessen the need for manual intervention by AEMO.

Proposal 2

AEMO to review the inputs, parameters and assumptions for the DFCM and test whether they should be updated to reflect current system conditions, and drive relevant and correct outputs.

Consultation question

Do stakeholders support the proposal for AEMO to review the inputs, parameters and assumptions for the DFCM?

4. Assessment of WEM FCESS economic performance

4.1 Market performance to date

Since the commencement of the New WEM on 1 October 2023, significant cost increases in FCESS were observed[17] and there have been further refinements to the pricing and other arrangements for FCESS.

The observed FCESS costs shown below in Table 4 will change, not only as a result of seasonal demand and renewable energy generation, but also through changes in Market Participant bidding behaviour and new market entrants.

The RCS costs shown below in Table 5 include Energy Uplift Payments made to Market Participants that were directed by AEMO following the 20 November 2024 ESM Rule changes.

[17] AEMO | Quarterly Energy Dynamics (QED)

Table 5: Monthly FCESS costs incurred (Market cost and FCESS uplift payments)

	FCESS costs ($m)				
Month	Contingency Reserve Raise	Contingency Reserve Lower	Regulation Lower	Regulation Raise	RoCoF Control Service
Feb 2024	$15.13	$2.51	$3.46	$2.98	$10.16
Mar 2024	$12.85	$2.98	$3.53	$3.20	$5.98
Apr 2024	$14.97	$4.15	$5.22	$4.25	$8.17
May 2024	$11.72	$3.35	$5.65	$4.61	$8.96
Jun 2024	$12.29	$4.45	$6.95	$3.04	$18.97
Jul 2024	$12.07	$2.76	$4.97	$2.75	$16.66
Aug 2024	$12.24	$1.92	$3.97	$2.92	$10.89
Sep 2024	$18.84	$3.29	$4.95	$3.65	$17.93
Oct 2024	$20.67	$4.82	$4.60	$4.38	$15.05
Nov 2024	$15.91	$3.41	$4.42	$3.01	$10.01*
Dec 2024	$7.57	$1.08	$1.74	$1.18	$1.00**
Jan 2025	$5.42	$0.77	$1.22	$0.97	$0.68**
Feb 2025	$5.98	$1.19	$1.52	$1.02	$0.34**

* Cost incurred between 1 – 20 November are $9.58m, with $0.43m in Energy Uplift Payments after 20 November 2024.

** Energy Uplift Payment made to AEMO directed RCS providers under clause 7.7.4. of the ESM Rules.

The monthly FCESS costs incurred over the twelve months from February 2024 show changes in Contingency Reserve Raise and RCS costs, most notably due to the following:

- Application of the $0 Offer Ceiling prices for RCS from 1 March 2024; and
- ESM Rule changes applied from 20 November 2024[18] that provide AEMO with the ability to direct generation, if shortfalls in RCS and RoCoF Safe Limit violations are identified, and compensate directed Market Participants with Energy Uplift payments rather than FCESS Uplift payments.

[18] Wholesale Electricity Market Amendment (FCESS Cost Review) Rules 2024

While RCS and Contingency Reserve Raise costs do show notable changes, Regulation Raise and Regulation Lower services and Contingency Reserve Lower costs remain reasonably constant and the services have not incurred any frequent shortfalls or required significant intervention.

Some of the observed changes in total costs may also have been influenced by seasonal variations in demand for FCESS:

- During periods of high renewable generation, there are often less synchronous generators online. This includes not only daytime periods of high rooftop solar production, but also periods of spring and autumn when operational demand is generally low, solar generation works most efficiently, and wind resources are high.
- Periods of minimal online synchronous generation, can increase Contingency Reserve Raise prices and heighten the risk of AEMO having to intervene and ensure sufficient RCS is online to manage system security.

4.2 Complexities of economic assessment

As stipulated under Section 3.15 of the ESM Rules, this Review requires:

- economic analyses determining the relationship between technical parameters (including, without limitation, frequency operating bands and Oscillation Control Constraint Equation parameters) and overall cost of supply of energy and ESS;
- a cost-benefit study on the effects on the Network and Market Participants of providing and using higher or lower levels of each ESS; and
- identification of the costs and benefits of changing technical parameters, including the potential for increasing or decreasing the overall cost to supply energy and ESS.

Such assessment would usually be conducted using a regression analysis that identifies a numerical relationship between energy and ESS costs, and technical parameters. These relationships would then be used to carry out cost-benefit assessments of varying technical parameters and/or quantities of ESS to understand whether opportunities existed to increase the benefit of the market to consumers of electricity.

Establishing the relationship between the technical parameters and costs has been challenging due to the changes in the market over the 12-month period of the Review. The ability to do regression analysis to meet the requirements of 3.15.1C(b) in this Review was impacted by the limited period since the new services commenced as well as the ongoing evolution of the market. During 2024 there were at least three notable market changes including:

- temporary administered price caps introduced in May 2024;[19]
- the significant reduction in all FCESS costs driven by the *Wholesale Electricity Market Amendment (FCESS Cost Review) Rules 2024* changes;[20] and
- the November 2024 ESR accreditation.

These changes exacerbated the complexity of any quantitative assessment. Additionally:

[19] The following changes were applied to correct unexpected and undesirable FCESS market outcomes, with the Offer Price Ceiling details available on the ERA website.

- Commencing 8:00 am on 1 March 2024 the RCS MW.s unit offer price ceiling from Market Participants was set to $0.[19]
- Contingency Reserve Raise Offer Price Ceiling reduced by ERA to $250 per MWh.
- Implementation of a temporary FCESS Clearing Price Ceiling between 22 May 2024 and 22 November 2024.

[20] Changes introduced by the 2024 FCESS Cost Review amendments, include:

- More efficient tie-break methods for FCESS and energy.
- Establishing a mechanism to allow AEMO to direct (and compensate) facilities in the event of consecutive periods of predicted violation of the RoCoF Safe Limit or RCS shortfall.
- Removing the payment of FCESS uplift payments for the provision of RCS.

The changes introduced were reported by AEMO in the May 2025 QED to have resulted in an uplift cost reduction of $38.6m.

- quantifying the sensitivities would have required full access to the DFCM; and
- the interdependencies between Contingency Reserve Raise and RoCoF made meaningful assessment difficult.

4.3 Scenario-based quantitative analysis

In the absence of the regression analysis, a scenario-based quantitative analysis approach using a series of case studies was undertaken to consider the impact of implementing some of the technical changes described in later in this section, including:

1. increasing the RoCoF Safe Limit to reduce the need for AEMO interventions;
2. assessment of contributions that MPFR can make to Contingency Reserve Raise procurement; and
3. investigating the implementation of synthetic Inertia provided by BESS in the WEM.

The case study analysis was not intended to quantify the entire cost or benefits but provide an indication of how material the changes could be to determine if there was value in further investigation. The case studies are described in the following sections.

4.4 Raising the RoCoF Safe Limit

The RoCoF Safe Limit is a key input to the DFCM[21] that determines the necessary quantities of Contingency Reserve Raise to be dispatched by WEMDE. A low RoCoF Safe Limit will require more Inertia, faster Contingency Reserve service, or a combination of both.

The RoCoF Safe Limit in the WEM is currently set in the FOS at 0.25 Hz per 0.5 seconds. Other power systems set a maximum RoCoF at or around 1 Hz per second over 1 second.

AEMO provided support to run a case study to assess the impact of increasing the RoCoF Safe Limit. The case study has been conducted by using RTFS studies that consider a week-long assessment with updated dispatch based on an increased RoCoF Safe Limit of 0.75 Hz per second over 0.5 seconds and investigates the impact of these changes on Energy Uplift Payments.

4.4.1 Setting a new RoCoF Safe Limit

The value of 0.75 Hz per second over 0.5 seconds as a RoCoF Safe Limit for the case study was recommended by AEMO, for both positive and negative RoCoF, based on consideration of:

- the international experience summarised in Appendix B;
- existing WEM frequency limits; and
- RoCoF ride through requirements, as well as RoCoF Ride-Through Capability of various generating equipment in the SWIS and the associated risks of exceedance.

[21] AEMO WEM Procedure: Essential System Service Quantities

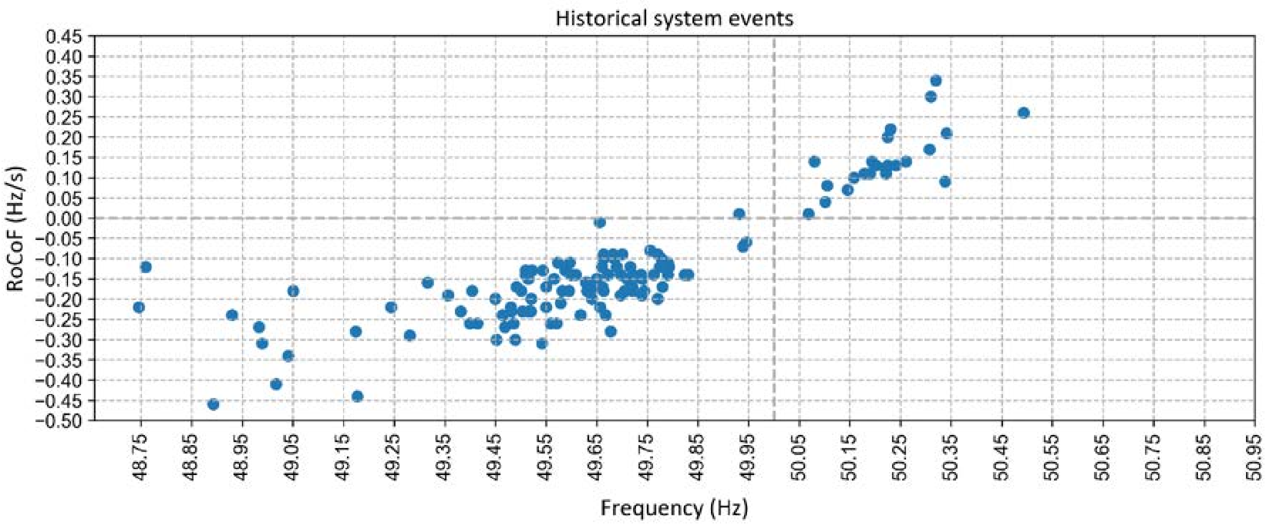

Figure 5: Historical system events and their calculated RoCoF

The largest disturbance recorded in the WEM was a -0.46 Hz per second for a loss of generation, and a +0.34 Hz per second change for load loss (Figure 5). For disturbances of this magnitude, Facilities in the SWIS are capable of riding through the contingency successfully.

When a Facility (with greater than 150 kVA aggregated capacity) was first connected under the Technical Rules, it was considered to be capable of meeting the 4Hz per second requirement (over an unspecified measurement period) in accordance with clauses 3.3.3.3(d)[22] and 3.6.5 of the Technical Rules, if exemptions[23] had not been provided.

Currently, there is only one 1.8 MW Facility in the WEM that has been granted an exemption from clause 3.3.3.3(d) of the Technical Rules. Several Facilities, despite first connecting under the Technical Rules, have an agreed Generator Performance Standard or are accredited for RoCoF Ride-Through Capability of less than 4 Hz per second.

All, but one, SWIS transmission connected Facilities have a known RoCoF Ride-Through Capability of more than 1 Hz per second over 0.5 seconds. The noted exception has twice shown that it is incapable of riding through positive RoCoF system events, including one with RoCoF as low as +0.14 Hz per second. However, the Facility has not shown similar behaviour during negative RoCoF system events, so its negative RoCoF Ride Through Capability is assumed to be 4 Hz per second.

In conducting its assessment, AEMO included a safety margin to account for the risks of:

- Facilities having RoCoF Ride-Through Capability less than 4 Hz per second despite having first connected under the Technical Rules; and
- Distribution connected Facilities that are not known to AEMO to withstand lower RoCoF.

AEMO recognises the limitations of gas and steam generation to withstand high RoCoF due to the risk associated with physical plant, control system responses, and protection relays.

[22] Technical Rules 3.3.3.3(d) Immunity to Rate-of-Change-of-Frequency: A generating unit and the power station in which the generating unit is located must be capable of continuous uninterrupted operation for any rate-of-change-of frequency of up to 4 Hz per second.

[23] ERA | Technical exemptions

4.4.2 Observed reduction in Directions

To assess the impact of reduced AEMO intervention and the correlating reduced Energy Uplift Payment costs that could result from increasing the RoCoF Safe Limit, AEMO conducted a further case study using the RTFS, examining the Dispatch Intervals between 8 to 14 December 2024.

The directions issued by AEMO during this period for the counterfactual scenario are summarised below in Table 6. For this case study, RoCoF Safe Limit of 0.75 Hz per second over half a second was implemented in the RTFS studies.

Table 6: Facilities directed for the purpose of RoCoF in the counterfactual scenario during the period from 8 to 14 December 2024 (inclusive)

Market Advisory #	Directed Facility	Invoked Constraint Equation	Dispatch Interval (start)	Dispatch Interval (end)
211147	NEWGEN_KWINANA_CCG1	[v1] NetworkCommit(NEWGEN_KWINANA_CCG1_Steam Bypass) * {NIL} [On(NEWGEN_KWINANA_CCG1)]	08-Dec-2024 07:30	08-Dec-2024 15:00
211148	PINJAR_GT11	[v1] NetworkCommit(PINJAR_GT11) * {NIL} [On(PINJAR_GT11)]	08-Dec-2024 10:50	08-Dec-2024 15:00
211149	ALINTA_WGP_GT	[v1] NetworkCommit(ALINTA_WGP_GT) * {NIL} [On(ALINTA_WGP_GT)]	09-Dec-2024 09:55	09-Dec-2024 14:55
211151	ALINTA_WGP_U2	[v1] NetworkCommit(ALINTA_WGP_U2) * {NIL} [On(ALINTA_WGP_U2)]	09-Dec-2024 12:50	09-Dec-2024 15:30
211153	ALINTA_WGP_U2	[v1] NetworkCommit(ALINTA_WGP_U2) * {NIL} [On(ALINTA_WGP_U2)]	10-Dec-2024 08:25	10-Dec-2024 15:25
211154	PINJAR_GT4	[v1] NetworkCommit(PINJAR_GT4) * {NIL} [On(PINJAR_GT4)]	10-Dec-2024 09:00	10-Dec-2024 14:35
211155	PINJAR_GT5	[v1] NetworkCommit(PINJAR_GT5) * {NIL} [On(PINJAR_GT5)]	10-Dec-2024 09:25	10-Dec-2024 10:20
211156	KWINANA_GT3	[v1] NetworkCommit(KWINANA_GT3) * {NIL} [On(KWINANA_GT3)]	10-Dec-2024 09:45	10-Dec-2024 14:15
211157	KEMERTON_GT12	[v1] NetworkCommit(KEMERTON_GT12) * {NIL} [On(KEMERTON_GT12)]	10-Dec-2024 10:10	10-Dec-2024 12:30
211175	NEWGEN_NEERABUP_GT1	[v1] NetworkCommit(NEWGEN_NEERABUP_GT1) * {NIL} [On(NEWGEN_NEERABUP_GT1)]	14-Dec-2024 09:20	14-Dec-2024 14:45

For each Dispatch Interval, the AEMO analysis removed the Directed Facilities (if any) from the dispatch and re-calculated the predicted worst-case RoCoF with the remaining Facilities. The analysis did not reflect what WEMDE would have dispatched (Energy or ESS) and what RoCoF could have been, if:

- those Facilities were not directed in the first place (relevant Constraint Equations were not invoked);
- the RoCoF Safe Limit were to be relaxed to 0.75 Hz per second for 0.5 seconds;
- RCS was co-optimised with Contingency Reserve Raise[24] and Largest Credible Supply Contingency.[25]

In the counterfactual scenario, Facilities were directed in 308 Dispatch Intervals during the period. After removing the directed Facilities, 37 Dispatch Intervals (12%) observe RoCoF higher than 0.75 Hz per second, with a maximum of -0.87 Hz per second.

Due to the oversimplified nature of the analysis, the results should not be directly interpreted as indicating that the directions would have been reduced by 88% following the relaxation of the RoCoF Safe Limit to 0.75 Hz per second.

The results suggest that for many of these Dispatch Intervals, there is a reasonable likelihood WEMDE could produce a Dispatch Solution in which RoCoF remains within the proposed Safe Limit, in the absence of the directions.

The value of the Energy Uplift Payments that could have otherwise occurred in the modified scenario compared to the counterfactual are shown below in Table 7.

Table 7: Energy Uplift Payments associated with directed Facilities in the RTFS analysis

Quantity	Value
Actual Energy Uplift Payments made to the relevant Facilities **for a one-week period** between 8 and 14 December 2024	$199,110.30
Energy Uplift Payments that would be payable under an amended RoCoF Safe Limit in the hypothetical counterfactual scenario	$103,678.48
Percentage reduction	-48%

The Energy Uplift Payments that would still be payable in the modified scenario are reflective of the Dispatch Intervals highlighted above, when the increased RoCoF Safe Limit would have been exceeded.

It is possible that these potential breaches to the RoCoF Safe Limit may not have occurred based on potential changes to WEMDE that AEMO is currently assessing (noted below). Avoidance of breaching the RoCoF Safe Limit would then also avoid the resulting Energy Uplift Payments to directed Facilities.

At the time of writing this paper, AEMO was undertaking two pieces of work related to Contingency Reserve to:

1. co-optimise the Largest Credible Load Contingency in WEMDE;

[24] Or Contingency Reserve Lower (CRL).

[25] Or Largest Credible Load Contingency (Largest Credible Load Contingency).

2. introduce linear RoCoF Safe Limit constraints for both the Largest Credible Supply Contingency and the Largest Credible Load Contingency.

Potential changes to WEMDE resulting from this work could have resulted in less constraints from WEMDE identifying a secure solution with a smaller credible contingency.

4.4.3 AEMO advice on increase to the RoCoF Safe Limit

AEMO has provided support and subject matter expertise in the consideration of an increase in the RoCoF Safe Limit, including any technical performance implications of an increase to the RoCoF Safe Limit over the course of this Review. On the current RoCoF Safe Limit:

- At the Transformation Design and Operational Working Group (TDOWG) meeting on 29 April 2020, AEMO suggested that RoCoF up to 0.5 Hz per second is a known Safe Limit because:
  - it is a stated “comfort” level from turbines’ original equipment manufacturers (OEMs);
  - there have been no known catastrophic failures industry-wide; and
  - it is a historical operating region in the SWIS, with maximum observed RoCoF 0.46 Hz per second (measured over 500 ms).
- For RoCoF between 0.5 Hz per second and 1.5 Hz per second, possible failures or mal-operation of various equipment, including synchronous generators, protection relays and DPV are highlighted.
- At the WEM Reform Implementation Group forum on 2 September 2021, AEMO assessed that the maximum RoCoF that may be experienced in the SWIS in the absence of RCS is 3 Hz per second over 0.5 seconds. The RoCoF Ride-Through Cost Recovery Limit was also set as 1 Hz per second.
- There is at least one Facility that is unable to withstand a positive RoCoF of as low as 0.14 Hz per second. No limitations for negative RoCoF below -0.5Hz per second have been observed.
- Accreditation for RoCoF Ride-Through Capability has been OEM/Market Participant supplied rather than AEMO tested or recorded, so these are OEM design levels rather than WEM verified performance (although the OEM supplied information can be considered a form of verification).

There are only 5 of 26 registered synchronous gas and steam generators that are accredited for RoCoF marginally above 1 Hz per second, with the majority operating under the default value of 1 Hz per second. At the same time, wind and solar Facilities are expected to remain connected for RoCoF of at least 3 Hz per second, while transmission and distribution network protection accredited to ride through RoCoF of at least 2.4 Hz per second

To recommend a suitable RoCoF Safe Limit that could be considered for the WEM, AEMO advised:

- under clause A12.7.3.2 of the ESM Rules, for a new Facility, its Generating System must be capable of riding through 2 Hz per second over 250 ms or 1 Hz per second over 1 second as a minimum. New Facilities will therefore ride through 1 Hz per second over 500 ms. An existing Facility connected under the Technical Rules may have capability below this minimum requirement;
- historically, the SWIS has not observed system events with RoCoF beyond ±0.5 Hz per second;
- synchronous gas and steam generating units present the biggest risks in the SWIS in respect of their RoCoF Ride-Through Capability. The five accredited gas units have shown that they are capable of riding-through just above 1 Hz per second, but there is no certainty that the other gas and steam generating units in the SWIS have the same capability;
- AEMO has no visibility of non-registered distribution connected Facilities of less than 5 MW;

- RoCoF Ride-Through Capability risks associated with protection relays, renewable Facilities and DPV have been identified as low to negligible;
- there will be alignment of the units for RoCoF used in the WEM with other jurisdictions and industry definitions from the currently used “Hz over 500 ms” to “Hz per second over 500 ms”; and
- the RoCoF Safe Limit should not exceed 1 Hz per second. To account for the risks of low RoCoF Ride-Through Capability of specific equipment, a safety margin is proposed to be the mid-way point between current Safe Limit and 1 Hz per second, i.e. 0.25 Hz per second. The RoCoF Safe Limit should not be greater than 0.75 Hz per second.

Normal operating frequency performance has been well above minimum requirements for the past year. However, meeting the FOS was not possible through AEMO’s procurement of FCESS alone, rather it was achieved through manual intervention by AEMO to manage the RoCoF Safe Limit.

The case study analysis shows the benefits to reducing the number of directions is twofold - avoided manual directions by the AEMO control room and avoided cost. The case study analysis demonstrated that:

- in a one-week period there were 308 Dispatch Intervals in which AEMO issued directions;
- the $103,000 saving was over that **one-week** period and, while this was a week in which directions were probably higher than average, those savings were indicative of overall cost saving.

In allowing the RoCoF Safe Limit to be higher there will be Facilities which can respond at lower inertia levels:

- this would allow AEMO to find safe dispatch outcomes at lower inertia levels; and
- AEMO would not have to intervene as frequently because the fleet configuration means that system secure outcomes can still be achieved.

Manual interventions should be avoided wherever possible because they can impede market effectiveness and efficiency. The reduction in manual interventions will see corresponding reduction to Energy Uplift Payments resulting in lower costs to the market.

AEMO is confident that running the system with a RoCoF Safe Limit of 0.75 Hz per second would be secure and would not lead to system wide failures. It has undertaken jurisdictional comparisons, various types of modelling and analysed potential outcomes to complete its due diligence, with all outcomes suggesting that generators can typically ride through the proposed amended RoCoF Safe Limit.

EPWA requests that stakeholders provide any available information that suggests that the proposal will endanger existing Facilities or suggest capabilities differ from those required under the Technical Rules, ESM Rules or the ESS accreditation process. This information will be essential to informing final recommendations.

Proposal 3

Increase the RoCoF Safe Limit from 0.25 Hz per 0.5 seconds to 0.75 Hz per second to reduce the need for AEMO interventions.

Consultation questions

Do stakeholders support the proposal to increase the RoCoF Safe Limit from 0.25 Hz per 0.5 seconds to 0.75 Hz per second to reduce the need for AEMO interventions?

Do stakeholders have supporting documentation to demonstrate that the proposed increase to the RoCoF Safe Limit may endanger existing Facilities?

4.5 Considering Mandatory Primary Frequency Response

Under the ESM Rules all generating Facilities are required to provide frequency responsive active power control, also referred to as MPFR. When MPFR is enabled with a narrow deadband it provides effective control of frequency during normal operation and Contingency Reserves during disturbances, subject to appropriate head- or footroom of active power.

To date MPFR contributions have not been accounted for in the FCESS procurement process. However, MPFR is considered in AEMO's operational tools such as the RTFS tool, through which the AEMO control room operators have visibility of MPFR in real-time.

Notably, the differentiation between Contingency Reserve Raise (and Contingency Reserve Lower) and MPFR is that the FCESS must be sustainable for AEMO to be able to contract it, while MPFR is frequency responsive subject to energy production. This implies that MPFR may not always be available when required.

4.5.1 Evaluating available MPFR

A case study to assess the potential impact on Contingency Reserve Raise procurement and price, selected eight Dispatch Intervals. The following days were selected on the basis of the highest number of market interventions and/or highest market cost of Contingency Reserve Raise dispatch:

1. 18:15 on 17 February 2025
2. 03:00 on 12 February 2025
3. 18:30 on 20 January 2025 (peak demand, no solar)
4. 11:15 on 18 January 2025
5. 01:00 on 27 December 2024
6. 18:25 on 11 December 2024
7. 14:25 on 11 December 2024
8. 13:00 on 23 November 2024 (min demand, with solar)

Before being able to input suitable values of MPFR into DFCM and WEMDE, it was necessary to determine the likely levels of MPFR[26] headroom that will be generally available and the sources that provide it. To be effective, specific quantities of Contingency Reserve Raise provided from any source must be sustainable by that Facility for consecutive Dispatch Intervals.

The generation duration curves for WEM Facilities that meet the following criteria were developed for the eight days for which the Dispatch Intervals noted above were analysed. The MPFR headroom for generating Facilities was calculated on the following basis:

- If the generating Facility is a solar- or wind farm, then MPFR is zero.
- If the generating Facility is unsynchronised then MPFR is zero.
- If the generating Facility is synchronised and dispatched for Contingency Reserve Raise then MPFR is zero.
- If the generating Facility is not a solar- or wind farm, not a charging energy storage resource, i.e. a BESS, synchronised, and not dispatched for Contingency Reserve Raise, then the amount of MPFR is calculated as the lesser of 30 percent of the generating unit or system rating or the difference in rating and dispatch:

[26] For the purpose of the assessment MPFR headroom is the difference between the Facility's rated capacity and the dispatch quantity.

$$\mathrm{MPFR} = \min(30\%\mathrm{UnitRating}, \mathrm{UnitRating} - \mathrm{MW\ dispatch})$$

- If the generating Facility is an energy storage resource (i.e. a BESS), not dispatched for Contingency Reserve Raise and is charging, then the MPFR is calculated as the lesser of 50 percent of the BESS rating or the difference in BESS rated output and dispatch:

$$\mathrm{MPFR} = \min(50\%\mathrm{UnitRating}, \mathrm{UnitRating} - \mathrm{Energy\ dispatch})$$

For BESS contributions the state of charge of the BESS has not been included, but may need to be considered if it is generally operated at maximum or minimum charge at particular times of day.

The calculated MPFR for each Facility is then adjusted based on a single Performance Factor (advised by AEMO for each Facility). The single value was selected to allow speedier calculation of MPFR contribution and has been chosen as a conservative average for each Facility during the day.

All provided and Performance Factor adjusted MPFR is then summated for every Dispatch Interval presented in the generation duration curve. The final MPFR considered to be capable of supporting Contingency Reserve Raise for each day is then selected to be the minimum MPFR seen in all Dispatch Intervals of that day.

Note that the MPFR from combined cycle power plant has conservatively been assumed as zero. This is because the steam turbine component provides limited frequency response and the output of the gas turbine is not able to be confirmed from the aggregated dispatch.

As illustrated below in Figure 6 for two days in December 2024, the potentially available MPFR varies throughout the day, but there is generally a good quantity present at any time.

The lowest levels of MPFR are accessible during the middle of the day when the Collie and Kwinana BESS are generally dispatched for Contingency Reserve Raise and many synchronous Facilities are offline. The Performance Factor adjusted MPFR is generally 100 MW lower than the raw MPFR, which is expected.

Figure 6: MPRF and actual Contingency Reserve Raise (12 and 27 December 2024)

4.5.2 Including Mandatory Primary Frequency Response in WEMDE

For the eight days selected, the lowest quantity of Performance Factor adjusted MPFR determined during any single Dispatch Interval is 82 MW. This amount of MPFR was next applied as an Offset to the amount of Contingency Reserve Raise to be procured in the WEMDE simulation for the selected Dispatch Interval. The resulting changes in Contingency Reserve Raise dispatch and prices, as well as overall market effect were assessed by comparing a counterfactual scenario simulation in which no MPFR was included against the one in which 82 MW of contribution was assumed.

A summary of critical observations is shown below in Table 8 (Green coloured cells indicate a reduction in prices and the red an increase). Key observations from the overall results of the MPFR assessment include:

- the performance adjusted MPFR is ranging between 82 MW to 515 MW indicating that MPFR contributions can be significant, even when adjusting for Performance Factors.
- excluding BESS entirely from MPFR contributions could significantly reduce headroom. However, for the days examined, the units are dispatched for Contingency Reserve Raise during peak demand and generally not dispatched for the remainder. These peak demand periods set the minimum MPFR levels, with these quantities provided solely from synchronous generation.
- at times of minimum demand in the middle of the day or at night time, Contingency Reserve Raise prices are often zero and, in such instances, the addition of MPR has no impact. However, there can be exceptions when prices are zero at other times.
- consideration of MPFR during evening peaks generally shows a reduction in costs to both Contingency Reserve Raise and Regulation Raise. Consequently, the consideration of MPFR appears to overall have a beneficial influence on market costs.
- one instance of increasing Regulation Lower prices was observed for an early morning Dispatch Interval. However, the same Dispatch Interval saw significant reductions in Contingency Reserve Raise, Regulation Raise, and energy prices.

Table 8: Changes to FCESS and Energy cost as a result of including 82 MW of MPFR (no changes in Contingency Reserve Lower or RCS are observed for any intervals)

Dispatch interval	Contingency Reserve Raise (AUD)		Regulation Raise (AUD)		Regulation Lower (AUD)		Energy (AUD)	
	No MPFR	MPFR = 82	No MPFR	MPFR = 82	No MPFR	MPFR = 82	No MPFR	MPFR = 82
23/11/24 - 13:00	0.00	0.00	0.00	0.00	154.7	154.7	-61.74	-61.74
11/12/24 – 14:25	60.06	60.06	16.01	16.01	0.00	0.00	149.75	149.75
11/12/24 – 18:25	473.9	60.06	473.9	278.46	0.00	0.00	738.00	728.28
27/12/24 – 01:00	0.00	0.00	0.00	0.00	0.53	0.53	92.09	92.09
18/01/25 – 11:15	60.79	0.00	0.00	0.00	60.00	60.00	-61.19	-61.19
20/01/25 – 18:30	735.18	100.2	733.71	727.74	0.00	0.00	883.00	883.00
12/02/25 – 03:00	60.06	0.00	23.3	0.00	1.75	1.95	121.65	93.41
17/02/25 – 18:15	0.00	0.00	0.00	0.00	0.00	0.00	119.2	119.2

The cost of FCESS uplift payment is not considered in the table above due to the difficulty quantifying the saving in FCESS uplift payments.

Additionally, one scenario in which MPFR contributions from Electric Storage Resources are excluded was assessed. In this case, the cost savings were significantly lower, indicating that BESS units contribute a substantial share of MPFR.

Based on observed outcomes it is recommended that the levels of Performance Factor adjusted MPFR available in the WEM should be investigated further by AEMO. It is recommended that a twelve-month monitoring program be implemented to capture daily and seasonal variations in system demand and dispatch, plant outages, DPV increases and other influencing factors.

The intent of the monitoring program is to provide confidence as to how much MPFR may be available at various times of the day and year, and for how long these quantities are generally sustained. It will then be possible to consider (and consult on) whether such quantities could be included in the FCESS calculation process as Offsets to Contingency Reserve Raise or Contingency Reserve Lower.

Proposal 4

AEMO to implement a monitoring program over a twelve-month period to track the amount of headroom and footoom available from unaccredited Facilities or non-dispatched FCESS Facilities to better quantify MPFR availability to assess the level of Contingency Reserve Raise and Lower that could be provided from the inclusion of MPFR.

Consultation question

Do stakeholders support the proposal to establish a twelve-month monitoring program for AEMO to track the amount of headroom and footroom available from unaccredited Facilities or non-dispatched FCESS Facilities?

4.6 Potential benefits of synthetic Inertia

4.6.1 Synthetic Inertia

The Inertia of a power system is a representation of its resistance to changes in electrical frequency, both in magnitude and rapidity of change. Inertia is a critical quality of a power system, as large and rapid excursions in electrical frequency can result in loss of generation and load or possibly even system wide blackout.

Inertia is presently supplied by synchronous machines in the form of rotational energy stored in the generators’ rotating masses. When system frequency declines, synchronous generators reduce their speed and convert rotational energy into electrical energy. When frequency increases, synchronous generators will speed up by converting electrical energy to rotational energy. A BESS can respond in a similar fashion, absorbing energy when frequency increases and injecting energy when frequency falls.

BESS are inverter-based systems capable of rapid current injection within fractions of a second. Virtual or synthetic Inertia that is supplied by grid-forming BESS is in the form of rapid power injection, sustained for a set time, in response to sudden change in electrical frequency.

Most jurisdictions are making changes to their ESS regimes based on increasing renewables. However, synthetic Inertia provided by BESS remains an area of investigation by many system operators rather than common practice, including in Australia.

Several utility scale BESS have been successfully commissioned in the WEM, and further BESS are committed or in advanced stages of commitment. The possible utilisation of these systems in the provision of synthetic Inertia should be considered by AEMO.

To be able to provide such services, the BESS will have to be grid-forming inverters. This would require control system upgrades as the systems currently installed constitute grid-following inverters that cannot provide synthetic Inertia services.

4.6.2 Synthetic inertia in the WEM

Synthetic Inertia provided by BESS is the rapid injection or absorption of energy by the storage system to emulate the inertial response of synchronous generators. The rapid injection of energy from a BESS is intended to reduce RoCoF following a system disturbance such as the loss of load or supply that would create an energy unbalance and therefore a change in frequency.

The two largest BESS operating in the WEM have been considered for a case study of how synthetic Inertia could affect the FCESS market outcomes. The Kwinana 2 BESS and the Collie BESS are rated at 225 MW and 219 MW, respectively, with each providing 4 hours of storage. For the purpose of the case study, both BESS are assumed to be converted to grid-forming inverters and capable of providing synthetic Inertia.

These ratings are comparable with the Hornsdale Power Reserve in South Australia that is considered to be able to provide up to 2,000 MW.s of synthetic Inertia. For the case study, the Kwinana and Collie installations have been assumed to conservatively be capable of providing 1,200 MW.s each.

From available market information, the two BESS are operating throughout the day, generally at less than 50% output. Based on this, it is reasonable to consider these two BESS to be capable of providing a synthetic inertia service at critical times, when there are predictions of RCS shortfalls or violation of the RoCoF Safe Limit.

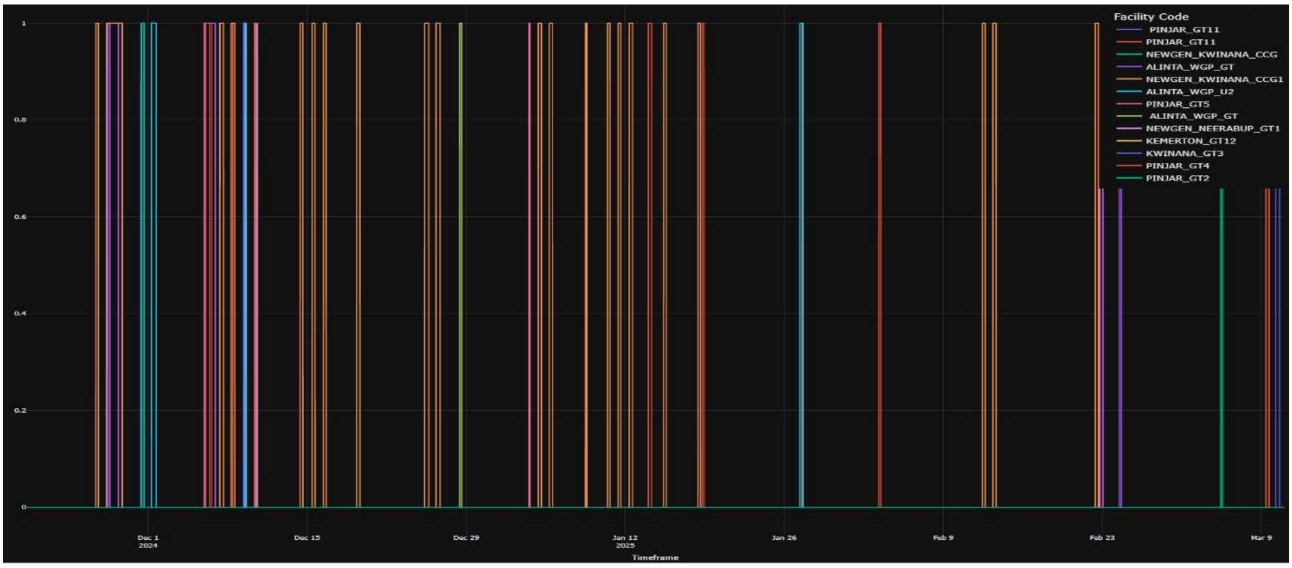

Figure 7: AEMO directions for RoCoF between November 2024 and April 2025

AEMO Market Advisories[27] state that in the six months from 20 November 2024 to 19 April 2025 AEMO issued a total of 90 directions over 56 separate days to address either RCS shortfalls or persistent predictions of RoCoF Safe Limit violations, i.e. to manage instances of insufficient System Inertia. Frequency of directions is illustrated below in Figure 7 which plots the number of directions and the generators directed to provide RCS.

The Market Advisories do not quantify the RoCoF shortfall and only note that one or more incidences occurred on the day and that particular synchronous generators were dispatched to ensure security.

As illustrated, these AEMO directions were issued to different synchronous generators with varying Inertia, from the Kwinana Closed Cycle Gas Turbine (CCGT) with 2,684 MW.s of inertia to the Pinjar Gas Turbine units 1 to 3 with 226 MW.s of Inertia each.

On some days multiple directions were issued, for example on 10 December 2024 when between 8:30am and 10:10am five separate generators were directed to commit and come online. The combined Inertia of the five generating units was 4,908 MW.s. On other days, only a single unit was directed, with the lowest single dispatch being 988 MW.s.

Observations of the analysed market data for the six-month period are shown below in Table 9.

[27] AEMO Market Data

Table 9: Impact of synthetic inertia on half-yearly AEMO directions to address shortfalls in RCS and breaches in RoCoF Safe Limit (Nov 2024 - Apr 2025)

#1	Total number of directions	90
#2	Number of days on which directions were issued	56
#3	Minimum Inertia dispatched on a single day of direction (MW.s)	988
#4	Maximum Inertia dispatched on a single day of direction	4,908
#5	Number of days on which more than 2,400 MW.s of Inertia was directed	30
#6	Number of directions that could have been avoided by adding 2,400 MW.s of synthetic Inertia	55

In summary, by assessing the Inertia of the synchronous generators directed online and comparing this against the 2,400 MW.s of Inertia that could be supplied by the two online BESS systems[28] it appears feasible that there were:

- 21 days when the presence of synthetic Inertia could have completely removed the requirement for direction;
- 29 days when the presence of synthetic Inertia could have significantly reduced the required directions; and
- 6 days when the Kwinana CCPP only was dispatched, and the two BESS would not have provided sufficient synthetic Inertia to avoid directions.

It is feasible that the observations are a conservative reflection of market outcomes in the instances when Kwinana CCPP was directed to provide RCS, and the actual shortfall could have been less than 2,400 MW.s. This would mean that the presence of synthetic Inertia from the two BESS could have also avoided direction on other days. Further information and analysis would be required to confirm this.

What can be concluded is that the presence of synthetic Inertia could potentially have significant impact on the need for AEMO market interventions and the Energy Uplift Payments to compensate synchronous generators to commit and generate. With the number of BESS projects announced for the WEM, the possible avoidance for directions could likely increase if synthetic Inertia can provide a suitable substitute for synchronous Inertia.

[28] Synthetic inertia that can be provided by BESS that is operating near maximum charge or maximum discharge will be less and generally maximum inertia is supplied when a BESS is operating below 70% of these output/input limits. For the purpose of this analysis and observation of BESS output during the dispatch intervals investigated this is the case.

Assessment of the introduction of synthetic Inertia on market outcomes was carried out for eight specific market Dispatch Intervals, including periods of high and low solar generation, and demand:

1. 18:15 on 17 February 2025
2. 03:00 on 12 February 2025
3. 18:30 on 20 January 2025 (peak demand, no solar)
4. 11:15 on 18 January 2025
5. 01:00 on 27 December 2024
6. 18:25 on 11 December 2024
7. 14:25 on 11 December 2024
8. 13:00 on 23 November 2024 (min demand, with solar)

Similar to the analysis to investigate the impact of increasing the RoCoF Safe Limit outlined above, two scenarios were considered for each interval - a counterfactual scenario and a scenario in which 2,400 MW.s of Inertia was added as an Offset to the DFCM output that is used in WEMDE.

The results indicated that, while there are increases to the available and dispatched RoCoF when 2,400 MW.s of Inertia is added to the system (Figure 8), there are also changes to Contingency Reserve Raise quantities, with some Dispatch Intervals flagging an increase and others a reduction (Figure 9).

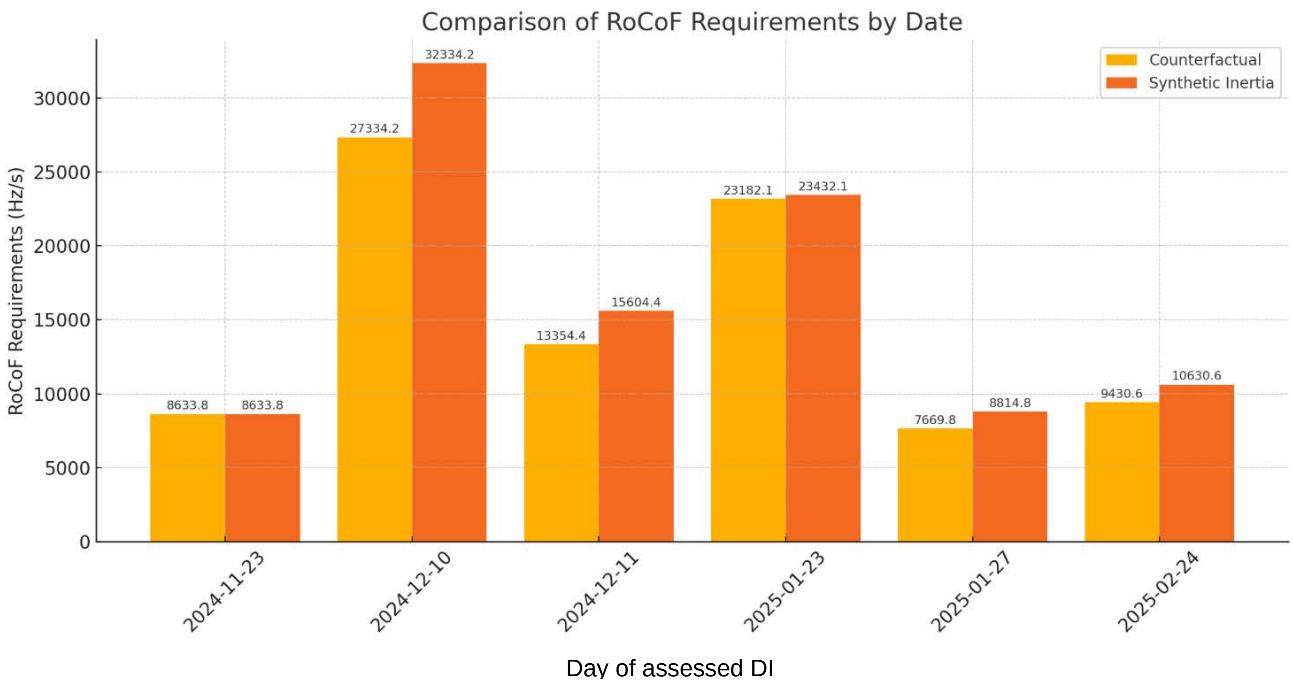

Figure 8: Changes to RCS requirements in WEMDE following addition of 2,400 MW.s of synthetic Inertia

The changes in Contingency Reserve Raise quantities cannot be explained by looking at a single Dispatch Interval and necessitate evaluation and ongoing monitoring by AEMO over a longer period.

Further consideration of synthetic Inertia would also need to include any related impact on other FCESS quantities and prices. A cost benefit analysis should therefore consider not only cost savings from reducing directions and the avoided Energy Uplift Payments but should also quantity any unit price changes in other FCESS such as Contingency Reserve Raise.

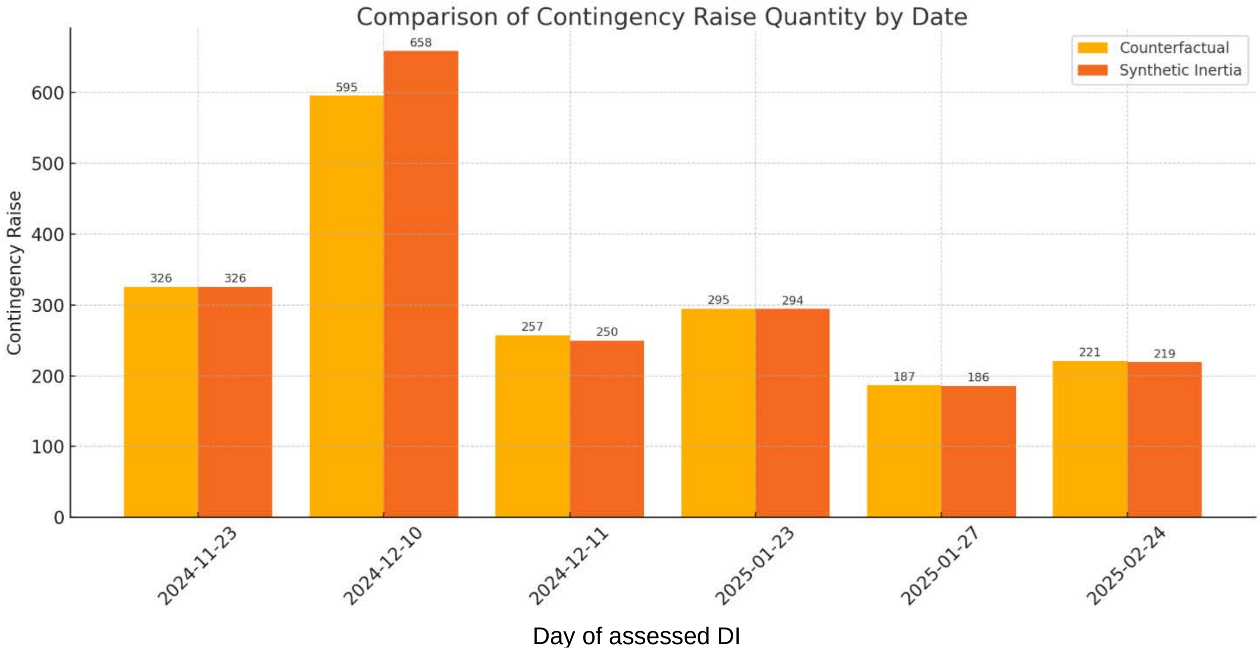

Figure 9: Changes to CRR quantities procured following addition of 2,400 MW.s of synthetic Inertia

It is not possible to estimate the economic benefits of adding synthetic Inertia as the following are unknown:

- the cost of avoided directions over the half year period considered;
- the cost differentials arising from changes in other FCESS quantities and prices; and
- the cost of incentivising BESS to provide synthetic Inertia.

However, the results are sufficient to highlight the likelihood of positive impact on market outcomes and further assessment should be conducted. As the economic benefits of introducing synthetic Inertia and the as-yet to be accepted equivalence of synthetic Inertia as a substitute for synchronous Inertia are unclear, it is recommended that:

1. AEMO conducts technical assessment through power system analysis, or trials with BESS operators, to verify the synthetic Inertia that these Facilities could offer. An assessment could further be enhanced by considering the experience in other jurisdictions such as the UK experience of the Pathfinder project and the establishment of verified performance criteria.
    - AEMO has commenced work in this area and aims to complete analysis by the end of June 2026.
2. AEMO estimates the avoided directions costs:
    - the Energy Uplift Payments over a half-year period by running simulations in a pre-production WEMDE environment using an RCS Offset of 2,400 MW.s, while considering the likelihood that provision of Inertia can restrict the BESS' ability to provide other services.

4.6.3 Incentives for synthetic Inertia

While the technical performance of BESS providing synthetic Inertia has already shown some positive results, the incentives for BESS to provide such services must also be considered. Currently, the WEM framework considers only Inertia as be a by-product of energy production by synchronous generators, with a price of $0 per MW.s.

Feedback collected from a member of the MAC ESS Framework Review Working Group (ESSFRWG) indicates that for a BESS to provide such services, there are costs that have to be considered, including for:

- upgrades to enable an existing grid-following BESSs to become grid-forming BESS;
- installing a new grid-forming BESS.
- commissioning and testing of a BESS intending to provide synthetic Inertia. The current understanding is that the complexity involved in testing a grid-forming BESS would be higher than that of a grid-following BESS;
- lost revenue in energy and FCESS markets due to retention of active power headroom that is required to provide synthetic Inertia. In particular, this requirement could limit the BESS participation in the RCM, which is the only fixed revenue stream for Market Participants; and
- reduced operating life of as grid-forming BESS used for synthetic Inertia is expected to have a significantly shorter economic life (5-10 years). This is due to the operational dispatch of multiple micro cycles per day to provide synthetic Inertia.

To incentivise and encourage BESS supplied synthetic Inertia, the ESSFRWG member’s feedback suggested that the following was required:

- confirmation of synthetic Inertia as an equivalent replacement of the synchronous Inertia currently used to limit RoCoF;
- consideration of suitable compensation mechanisms to maintain the state of charge necessary to deliver an agreed level of synthetic Inertia;
- investigating appropriate arrangements to ameliorate the potential lost revenue due to retaining active power headroom to provide synthetic Inertia, which would limit participation in other markets;
- publication of indicative future Inertia shortfalls by AEMO that could allow BESS owners and developers to consider their business case for the provision of synthetic Inertia;
- long term contractual arrangements for the provision of synthetic Inertia to provide a BESS operator with confidence in investment; and
- adaptation of generator performance standards to allow a grid-forming BESS to appropriately tune control system parameters to supply synthetic Inertia.

In its submission to the AEMC’s *Efficient provision of Inertia* directions paper, battery system manufacturer Tesla provided its projected costs of supplying synthetic Inertia[29]. While there are limited comparable data sets and publications available at present, these projected costs can provide a starting point for consideration.

While local and global developments are working towards the inclusion of BESS supplied synthetic Inertia in electricity systems, the ESSFRWG members noted the importance of a balanced sourcing of Inertia services, including both synchronous Inertia from generators or synchronous condensers, and synthetic Inertia from grid-forming BESS.

Introducing synthetic Inertia into the WEM will require further assessment.

Proposal 5

Assess of suitability of synthetic inertia (RCS) from BESS in complementing synchronous inertia from rotating machines, and consider potential barriers and suitable incentivisation for grid-forming BESS to provide such services.

[29] Tesla response to AEMC’s 2025 direction paper for Efficient Provision of Inertia

Consultation questions

Do stakeholders support further analysis and assessment by AEMO to assess the suitability of synthetic Inertia from BESS in the WEM?

Do stakeholders support further investigation to better understand the incentives required to support this?

5. Metrics for monitoring FCESS performance

Under clause 3.15.2 of the ESM Rules, as part of each review conducted under clause 3.15.1A or clause 3.15.1B, the Coordinator, with the support of AEMO, must determine and publish a set of metrics to be used for ongoing monitoring of ESS, which must include:

a) technical outcomes, such as dispatched ESS quantities, number of accredited Facilities, number of capable Facilities and the historical performance of those Facilities;

b) financial outcomes, such as Market Clearing Prices and ESS costs; and

c) economic outcomes, such as the overall electricity costs faced by consumers.

The metrics will be applied to the power system operational processes to provide a measure of their overall performance. These performance indicators can then be used to verify compliance with target outcomes or improve the process or requirements, as needed.

In accordance with the State Electricity Objective, procurement of FCESS must be in the long-term interest of consumers in relation to system security, cost and the environment. Of these, it is the system security and the price of FCESS that can provide suitable metrics. There are two aspects that are to be monitored and for which appropriate metrics will be developed:

1. Technical performance in line with the FOS in the WEM.
2. Economic performance that maximises the benefits to consumers.

As this is the first review of the ESS Process and Standards the metrics and targets are presented as a basis for discussion and require further development and consultation with AEMO prior to implementation.

Following industry consultation and considering any appropriate amendments to address stakeholders input, once suitable metrics and targets are established with AEMO, they will be included in the Information Paper as required under 3.15.3(d) of the ESM Rules and published on the Coordinator’s website.

5.1 Technical performance monitoring

5.1.1 Regulation service

Metrics for monitoring frequency performance should be based on FOS quantities. Comparing the FOS requirements against the measured frequency performance during normal system operation outlined in Section 2.1.1, there are several conclusions that can be drawn about the performance of frequency regulation:

- Frequency performance (Figure 1) meets the requirements of the FOS.
- Actual frequency performance of greater than 99.8% is significantly higher than the FOS requirement (Figure 2). This could imply that the quantity of regulation ESS being procured is excessive and should be reviewed.
- There appear to be periods of extra volatility in frequency that result in more breaches of the normal operating band than other times (Figure 1) for example, summer 2024/25. There may be benefits to considering whether the 30-day rolling window of measurement should be

reduced, to more accurately show normal operating band violations and whether these are diurnal, seasonal, or related to generation dispatch in some other way.

- Utilisation of the set procured regulation quantities appears on average very high for example, the amount of Regulation set by the RBM for time of day and cloud cover is regularly exceeded by AEMO control room operator intervention and additionally being fully dispatched during a Dispatch Interval (Figure 3). A review of the Regulation quantity specification should be considered.
- Regulation procurement often exceeds the default quantities outlined in the ESS quantification for time of day and atmospheric conditions (Table 2). This is due to AEMO control room operator intervention or operational forecasting action. Such intervention is required during times when higher volatility in the supply-demand balance is expected for example, high DPV volatility due to increasing cloud movement. A review of the Regulation quantities should be undertaken.

Proposed metrics and targets to measure the performance of WEM Regulation

Based on the noted observations, the following metrics and targets to measure the performance of WEM Frequency Regulation are proposed:

1. Efficient quantities of Regulation Raise and Lower are being procured assessed through lagging metrics such as:
   - Normal operation system frequency remains within the normal operating band 99% of the time during any 30-day rolling window.
   - Average Area Control Error (ACE) over any Dispatch Interval remains within a specified boundary for at least 90% of the time in any rolling 30-day time window; the boundary would be defined as a function of the system frequency bias used to determine Regulation quantities.
   - Frequency time error limit <10 s for 99% of the time over any rolling 30-day period.
   - Average utilisation of each of the Regulation Raise and Regulation Lower quantities procured during a Dispatch Interval to be monitored and reported on over every calendar month.
2. Quantifying scarcity of Regulation services offering, as a leading metric:
   - Accreditation of Regulation services is at least 300% of the maximum required during the past year.
   - Regulation quantities offered (Available and In-Service) for a 7-day outlook period by registered FCESS entities is at least 150% (or some other statistically determined value) of the quantities required.
   - Forecast error i.e., difference in RBM assigned and control room operator dispatched Regulation, used to quantify the required amount of Regulation Raise and Regulation Lower services improves over time, as the statistical relationship between ESS quantities and the input parameters to the RBM become more defined.

5.1.2 Contingency services

RCS and Contingency Reserve Raise and Lower services are interdependent and should be included in the same consideration of Contingency services metrics. This interdependence is reflected in the DFCM look-up tables and outputs. As the DFCM provide the input to WEMDE it is appropriate for RCS to also be considered.

In identifying performance metrics for Contingency Reserve services, it is important to:

- differentiate between Contingency Reserve services used to manage system frequency and individual generator performance in delivering their WEMDE dispatched services;
- understand the impact of MPFR provided by all generators in the SWIS on frequency excursions and improving contingency recovery;
- separate times that AEMO was required to intervene and direct facilities to provided ESS due to RCS shortfalls or other system security triggered interventions, from those where the FCESS market did not experience shortfalls and worked without system operator direction; and
- anticipate changes to System Inertia due to synchronous generator retirements that will increase RoCoF over time and hence the quantity and performance of Contingency Reserve Raise (and Contingency Reserve Lower).

AEMO considers many of these factors and others in the DFCM and the RTFS when determining how much Contingency Reserve services to procure and dispatch to manage the system securely. Many of the inputs to their processes are not directly controllable, or may be uncertain or variable.

Metrics that monitor ESS performance therefore, should look at the system as a whole, rather than individual generator compliance, or quantities that are not controlled. A metric that measures the performance of individual generators is out of scope for this Review and not included, instead the aggregated response of Contingency Reserve service providers should be monitored and reported.

Monitoring of FCESS and FCESS market performance must also include tracking the number of interventions by AEMO necessary to maintain system security. Excessive intervention from AEMO to procure additional FCESS beyond the WEMDE solution could suggest insufficient procurement of services, an ineffective process for quantification, lack of participation or a combination of any of these.

- the case study analysis clearly demonstrates the benefits to reducing the number of directions in the market are twofold – avoided manual directions by the AEMO control room operator and avoided cost. Manual interventions should be avoided because they can distort the market.

It could also suggest changing system conditions, for example falling System Inertia or an increase in consumer energy resources that reduces system demand. A process for tracking the number of interventions will be part of the SESSM Service Specifications to be developed under clause 3.15A.46. of the ESM Rules.

To date the small number of contingency events recorded in the WEM (Table 3) have all been managed securely, with the frequency nadir or zenith not exceeding the Credible Contingency Event Frequency Band or creating a RoCoF beyond the RoCoF Safe Limit.

Given the limited number of events and availability of the details surrounding these, limited technical performance metrics that monitor Contingency Reserve or RCS services are identifiable. However, some of those that are feasible include:

- achieving compliance with the FOS for not exceeding the Credible Contingency Event Frequency Band or the RoCoF Safe Limit, noting that achieving compliance is based on use of reasonable endeavours;
- frequency of Contingency Reserve shortfalls in the market and minimising the need for directions by AEMO;
- reasonable dispatch of RCS and Contingency Reserve Raise (Contingency Reserve Lower) services sufficient to meet the Largest Credible Supply Contingency;
- efficient co-optimisation with RoCoF services and energy dispatch to minimise the Largest Credible Supply Contingency;
- expansion of Contingency Reserve Raise and Contingency Reserve Lower accreditation to additional (new or existing) Facilities to increase the pool of Contingency Reserves available;

- accuracy of DFCM and RTFS modelled Contingency Reserve Raise and Contingency Reserve Lower service requirements; and
- available MPFR to optimise procurement Contingency Reserve Raise and Contingency Reserve Lower FCESS.

Proposed metrics and targets to measure the performance of WEM Contingency services

To monitor the performance of Contingency services for the WEM, the following metrics and targets are proposed:

1. Maintaining the FOS: No violation of the Credible Contingency Operating Band occurs in the SWIS over any 12 month period.
2. Maintaining the FOS: No single Credible Contingency Event creates RoCoF greater than the RoCoF Safe Limit.
3. Accuracy of the DFCM: Co-optimised WEMDE procured Contingency Reserve Raise or Contingency Reserve Lower services do not exceed the DFCM set Contingency Reserve Raise Offset amount for at least 90% of the time in any rolling 30-day time window.
4. Market participation: No shortfalls in Contingency Reserve Lower or Contingency Reserve Lower services occur during 99% of Dispatch Intervals for any 90-day period, or the number of Dispatch Intervals specified in the WEM Procedure required by clause 3.11.4 of the ESM Rules.
5. Market Participation: Contingency Reserve Raise and Contingency Reserve Lower accredited ESS facilities are offering services at least 90% of the time they are in service, during any 30 day rolling window. This is a market participation observation rather than an ESS performance metric.
6. Market Participation: Accredited Contingency Reserve Raise in the market is at least 250% of maximum Contingency Reserve Raise requirements.
7. Market Participation: Accredited Contingency Reserve Lower in the market is at least 250% of maximum Contingency Reserve Lower requirements.
8. Market intervention: Frequency of RoCoF shortfalls does not exceed the quantity set to trigger SESSM, as specified in the SESSM specifications to be developed under clause 3.15A.46. of the ESM Rules.

Noting that the FOS of the ESM Rules refers to retaining frequency within the containment bands as being one of best endeavours, such that statistical metrics could also be applied e.g., containment for 90% of the time.

5.2 Economic performance metrics

The FCESS framework changes applied during the first twelve months of new market arrangements have seen downward trends in FCESS costs (Table 4). While Regulation services costs appear to have remained somewhat stable, the largest observed changes were in the reduction to Contingency Reserve Raise and RCS.

The three case studies outlined in the previous section considered the economic impact on FCESS prices and quantities by changing technical parameters.[30] The analysis was not intended to

[30] The case studies included:

1. Increase in the RoCoF limit to 1 Hz per second
2. Offsetting Contingency Reserve Raise requirements by 82 MW of MPFR.
3. Inclusion of 2,400 MW.s synthetic inertia in the FCESS arrangements

quantify the entire cost or benefits but provide an indication of how material the changes could be to determine if there was value in further investigation.

Due to time restrictions and the complexity of the assessment involved, the studies were only conducted for a small set of Dispatch Intervals, sufficient to provide insight into the anticipated effect these changes could have on FCESS quantities and prices. Similarly, as the reconstruction of the counterfactual cases to remove directions that may have occurred is complex and time consuming, these directions have been retained in the WEMDE reruns with the changed system parameters.

The effect of this may be reflected in slightly higher values of Inertia that may otherwise have occurred and possibly more accredited Contingency Reserve Raise providers being available. This could positively impact economic outcomes, but is considered reasonable for a preliminary assessment.

In summary the case studies indicated that:

1. Increasing the RoCoF Safe Limit from 0.5 Hz per second to 0.75 Hz per second[31] could reduce the need for AEMO interventions and associated Energy Uplift Payments by allowing higher RoCoF events without compromising system security. AEMO analysis and simulations showed little change in the required Contingency Reserves under current dispatch conditions and indicate potential for greater operational flexibility and cost savings, by allowing generators with low Performance Factors to participate in RCS at lower system Inertia levels.
2. Inclusion of MPFR in the FCESS process to reduce the Contingency Reserve Raise Offset parameter used in WEMDE can substantially reduce Contingency Reserve Raise quantities and unit prices.
3. Contributions of synthetic Inertia from grid-forming BESS can reduce the need for intervention by AEMO to address RCS shortfalls or breaches of the RoCoF Safe Limit, subsequently reducing potential Energy Uplift Payment costs to the market.

Proposed metrics and targets to measure the performance of FCESS markets

In light of the FCESS market performance, and the case study outcomes and insights, the following metrics and targets are proposed:

A. Market cost: Tracking and monitoring the quarterly FCESS cost for each service.

B. Market participation: Monitoring the quantities of Contingency Reserve Raise being offered in the market compared to the Contingency Reserve Raise requirements.

C. Market intervention: Monthly Energy Uplift Payment costs paid for RCS directions

D. Market volatility: Average monthly cost of Contingency Reserve services during seasons are stable or trending downwards, while the monthly seasonal statistical distribution of Contingency Reserve costs over an appropriate time frame has a low standard deviation; high standard deviations of costs could reflect significant volatility in the cost of services due to shortfalls, applied price caps, market interventions, or changing market conditions. Differentiating seasonal variability in Contingency Reserve Raise is important as outcomes for low demand and high renewable penetration experienced in the shoulder seasons will be very different from high demand and high synchronous generator penetration.

31 RoCoF is commonly defined in Hz per second. However, the critical period occurs during the first 500 ms when frequency response is predominantly inertial as synchronous machines cannot increase their active power output instantly. Hence, while expressing RoCoF in Hz per second, AEMO also defines that this RoCoF rate will apply to the first 500 ms.

5.3 Market monitoring

The FCESS Cost Review changes implemented during 2024 drove significant changes to the total cost of services. AEMO reported that Q1 2025 FCESS costs, including Uplift costs, were $48.4 million, a decrease of $49.5 million (-51%) from Q1 2024[32]. The most significant drivers for the decrease were changes implemented as part of the FCESS Cost Review. Further, the market contributions by BESS that came online during 2024 presented downward pressure on FCESS clearing prices.

AEMO also reported a significant increase in energy uplift costs from $2.4 million in Q1 2024 to $12.9 million in Q1 2025, with $1.3 million of this amount contributed by RCS directions. However, AEMO notes that the largest contribution to the total cost was as a result planned network outages in late March 2025 rather than due to market interventions for RCS shortfalls or RoCoF Safe Limit breaches.

Correspondingly, FCESS prices have been decreasing, as noted above and illustrated in Table 4. Given these downward trends, the most meaningful metric is to continue monitoring FCESS costs and usage. However, given the increases in frequency of market intervention since 20 November 2024, this indicates that further assessment of the market mechanisms are necessary since market interventions are an indication of scarcity, lack of participation, or other indicators that the current FCESS framework is not working as anticipated and desired.

6. Supplementary ESS Mechanism

The SESSM forms part of the broader FCESS market reform program endorsed by the Energy Transformation Taskforce, which was established in 2019 to address some of the key challenges of the energy transition Taskforce in August 2019[33].

The SESSM was introduced as a mechanism for procuring FCESS to provide a means for longer-term contractual arrangements in case of inadequate supply of FCESS in the Real-Time Market. The objectives of the SESSM are to:

- incentivise new FCESS providers to enter the market;
- mitigate scarcity in FCESS markets, which may manifest as either as a shortfall of accredited facilities, or shortfall of participation; and
- mitigate the use of market power by:
  - providing a mechanism for competitive entry of new providers; and
  - allowing a mechanism of ex-ante review of the operating costs of ESS providers by the Economic Regulation Authority (ERA).

The SESSM is triggered if:

- AEMO identifies a shortfall of FCESS capable Facilities and the shortfall cannot be met by Market Participants or the number of Dispatch Intervals in any 90 Trading Day period identified in clause 3.11.2(b) is greater than or equal to the threshold specified in the WEM Procedure referred to in clause 3.11.4 of the ESM Rules; or if
- the ERA identifies through its monitoring activities that market outcomes are not consistent with efficient operation, or if the overall market prices are significantly above a level.

[32] AEMO Quarterly Energy Dynamics Q1 2025

[33] The Energy Transformation Taskforce

6.1 Review of the SESSM

An output of a review of the ESS Process and Standards required under Section 3.15 is a review of the processes and effectiveness of the SESSM. It was therefore appropriate to undertake a review of SESSM in conjunction with the review on the ESS Process and Standards to ensure that the core processes and design elements of the SESSM and the relevant obligations are fit for purpose and work as intended.

There has been no activation of the SESSM since new market commencement and many of the SESSM specifications to be developed under clause 3.15A.46 of the ESM Rules are not yet published. Consequently there is insufficient information available to conduct a meaningful review of the SESSM at this stage.

The following areas have been identified as requiring further investigation of the SESSM framework following publication of these specifications and collation of market data as to their effectiveness.

- Incomplete or unpublished procedures create a lack of process and specification transparency that must be addressed, including specification of the following matters in appropriate procedures:
  1. SESSM Trigger – procedures defining when the SESSM is activated (clause 3.11.4)
  2. SESSM Service specification – procedures defining the SESSM Service specification included in overall SESSM (clause 3.15A.46)
  3. SESSM procurement – specification defining the information to be provided by a SESSM respondent (clause 3.15A.20)

Appendices

Appendix A. Review of frequency performance in the WEM

This section presents a review of how effectively FCESS have supported and maintained the SWIS frequency within the defined FOS since the New WEM Commencement Day on 1 October 2023. The evaluation is based on analysis of measured frequency data sourced from two monitoring systems:

- SCADA Measurements – Low-resolution data recorded every four seconds, representing continuous system monitoring; and
- High-Speed Recorder Measurements – High-resolution data captured in milliseconds, typically triggered following contingency events.

The technical assessment is also informed through:

- a jurisdictional comparison of the National Electricity System (NEM), Ireland and New Zealand. The three jurisdictions were chosen due their comparable levels of demand, market structures, and/or renewable generation penetration to the WEM, to gain insight into their management of system frequency; and
- engagement with AEMO technical and subject matter experts who provided further clarification and background to market behaviours, technical responses, as well as ongoing developments in frequency management procedures.

A.1 Meeting the WEM Frequency Operating Standard

The relationship between FCESS and the FOS is defined in Chapter 3B and Appendix 13 of the ESM Rules. AEMO is required to schedule and dispatch sufficient quantities of these services to maintain system frequency within the limits set by the FOS, under normal operating conditions and following Credible Contingency Events.

FCESS are procured through market mechanisms with accredited Facilities being able to make offers for the relevant service and subsequently potentially be cleared in dispatch. Allocation of FCESS is co-optimised with energy to achieve the most cost-effective combination of energy and ESS for a Dispatch Interval. This ensures that the power system remains resilient to disturbances while minimising costs to consumers.

The algorithm of co-optimisation is the WEMDE that takes offers for energy and FCESS and determines the most efficient solution. While there are rules for tie breaking and prioritising energy over FCESS, there are limits to the existing optimisation algorithm, in which non-linear real-world relationships must be modelled as linear constraints.

The FOS establishes the target frequency of 50 Hz for the SWIS under normal operating conditions, as well as a containment and recovery band following credible disturbances. The FOS specifies a series of frequency bands and performance expectations that apply to different system states are shown below in Table 10.

Table 10: FOS Frequency Bands and defined limits

Operating Frequency Standard Terms	Specification
Normal Operating Frequency Band	49.8 Hz to 50.2 Hz for 99% of the time over any rolling 30-day period
Normal Operating Frequency Excursion Band	49.7 Hz to 50.3 Hz, with recovery to the Normal Operating Frequency Band within 5 minutes
Credible Contingency Event Frequency Band	48.75 Hz to 51 Hz, with recovery to the Normal Operating Frequency Band within 15 minutes. For over-frequency events, frequency must be reduced to below 50.5 Hz within 2 minutes
Island Separation Frequency Band	Similar to the Credible Contingency Event Frequency Band (48.75 Hz to 51 Hz), with the same recovery expectations when parts of the SWIS become islanded
Extreme Frequency Tolerance Band	47 Hz to 52 Hz (reasonable endeavours), with time-based recovery targets depending on whether the deviation is above or below 50 Hz
RoCoF Safe Limit	0.25 Hz per 500 milliseconds

The importance of monitoring and reporting frequency performance against a set criteria or metrics is recognised by many jurisdictions.[34] Assessment and conclusions presented in this report have been derived from raw data supplied by AEMO.

A.2 Regulation

Regulation services play a critical role in managing minor and continuous frequency deviations within the Normal Operating Frequency Band (49.8–50.2 Hz) of the SWIS. These services enable the system to respond to small mismatches between supply and demand under normal operating conditions. Services are affected by AEMO sending regular set point changes to generators via the AGC.

The ESM Rules that apply to the procurement of Regulation FCESS are based on sufficiency of selected quantities with flexibility to increase procurement when necessary:

- Clause 3.10.1 of the ESM Rules requires AEMO to ensure that sufficient quantities of ESS are scheduled and dispatched to meet the ESS Standards, including those necessary to maintain frequency within the FOS.
- Clause 3.10.2 of the ESM Rules requires AEMO to continuously monitor the performance of the power system and make operational decisions to ensure that frequency control services are effectively maintained, including issuing dispatch instructions as necessary to manage

[34] AEMO published frequency performance as part of the AEMO | Ancillary Services Report for the WEM under 3.11.13 of the former WEM Rules until June 2023. In the NEM, AEMO publishes frequency performance reports weekly.

system frequency in real time. AEMO is also required to take into account historic expected variability of the frequency when scheduling and dispatching this service

Regulation services are procured as an FCESS, with separate raise and lower quantities. AEMO can apply real time adjustments (increases to Regulation quantities) through operational forecasting up to 24 hours ahead or Control Room operator decision to finalise Regulation Raise and Regulation Lower quantities ahead of dispatch, as they deem are necessary.

The percentage of time the frequency remained within the Normal Operating Frequency Band consistently exceeds the 99% threshold required by the FOS.[35]

This level of performance implies a very narrow frequency distribution, indicative of a very tight frequency management. This is illustrated below in Figure 10, which provides a more detailed view of daily frequency variations by plotting the probability density function of the measured daily frequency, offering further insight into the distribution of frequency outcomes.

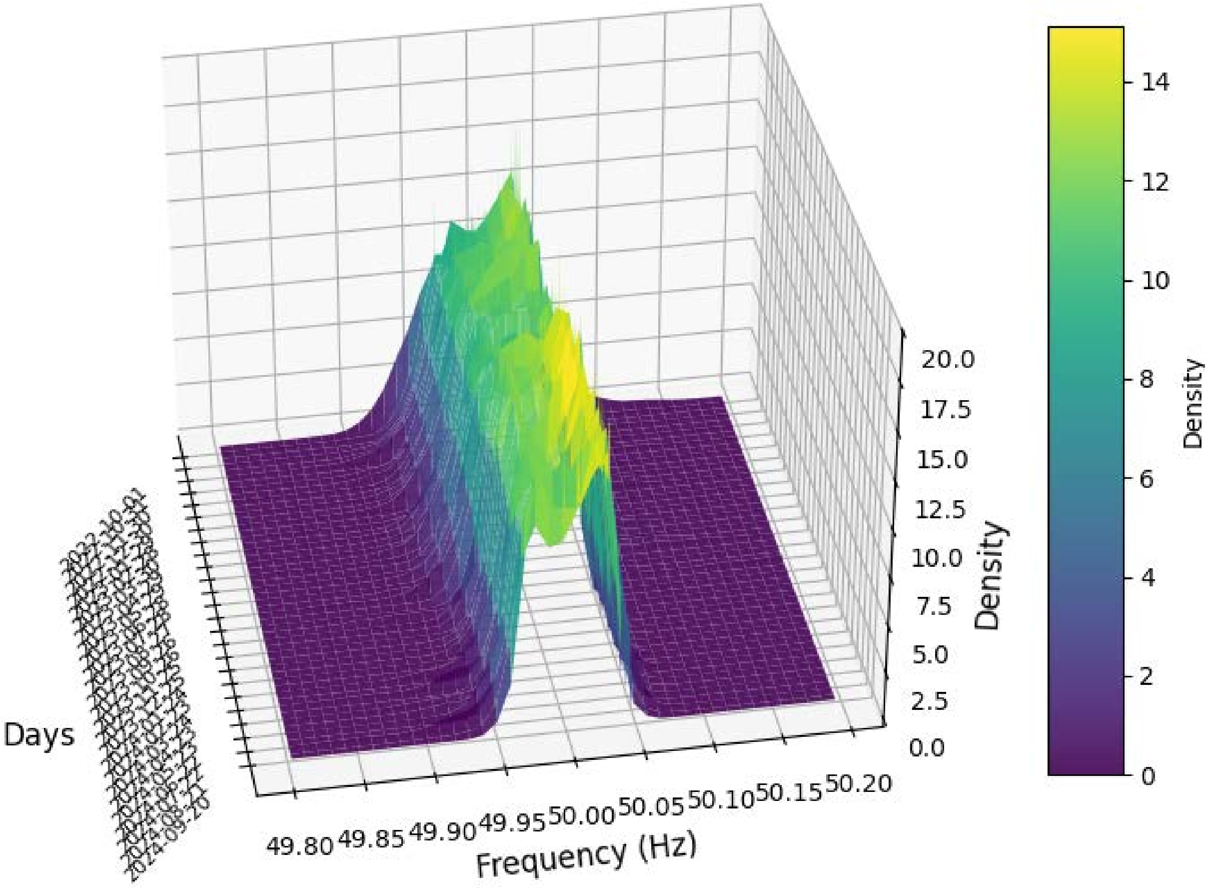

Figure 10: Probability Density Function of daily measured frequency

The observations demonstrate that the existing FCESS mechanisms have been effective in maintaining compliance with the FOS, with respect to the Normal Operating Frequency Band. The observations demonstrate that AEMO's procurement of Regulation services has been at least

35 Frequency does exceed the Normal Operating Frequency Excursion Band of 49.7 and 50.3 Hz in some instances but it is contained and returned to within the Normal Operating Frequency Band within five minutes in all instances, as required by the FOS.

sufficient to manage system frequency during normal operating conditions. There is no evidence of deterioration in frequency quality since New WEM Commencement Day based on the following:

- The FOS itself did not change;
- Quantities of regulation FCESS procured largely remained the same;
- MPFR was in effect prior and post new market commencement supporting normal operating frequency; and
- The fundamental physics of the SWIS remained unchanged, apart from evolving factors such as DPV uptake, demand variations, and changes in the generation mix.

No significant impact on normal operating frequency performance was expected or observed following New WEM Commencement Day.

A.3 Contingency response and RoCoF Control Services

Contingency Reserve Raise and Contingency Reserve Lower services present rapid response to large changes in system frequency resulting from an unplanned loss of a generator or block of load. These services are to ensure a nadir or zenith of frequency excursions resulting from a credible contingency is achieved within the necessary time to contain frequency within the Credible Contingency Event Frequency Band of 48.75 to 51 Hz.

The FOS for Credible Contingency Event Frequency Band has also a requirement of 15 min recovery time to 49.8-50.2 Hz.

Contingency Reserve quantities to be procured are determined based on system conditions, with sufficient quantities procured to maintain stability following the sudden and large disconnection of generation or load. The simplified process[36] is outlined below:

1. AEMO analyses the system configuration and historical occurrence to determine the set of Credible Contingency Events it should prepare for;
2. AEMO models system performance and determine the necessary quantities of contingency services required to manage the set of Credible Contingency Events to meet the FOS; and;
3. AEMO operates the Real-Time Market to purchase the necessary quantities and dispatch these among the fleet of accredited Facilities accordingly.

Contingency Reserve Raise (or Contingency Reserve Lower) and RCS in high Inertia systems, whether through market conditions or AEMO intervention, require less fast responding reserves and enable slower generators to also contribute. Vis-a-vis, low Inertia systems will require more and potentially faster reserves to ensure frequency decline is arrested and frequency recovered before it breaches the Credible Contingency Event Frequency Band.

Other electricity markets differentiate between the speed of response of generating facilities by establishing multiple and time sequential markets such as the NEMs Frequency Control Ancillary Services markets.[37]

AEMO uses the DFCM to simulate system frequency response for a range of operating conditions called ESS System Configurations. Each configuration includes:

- Underlying System Load;
- Load Relief Factor;
- Speed Factor;

[36] AEMO WEM Procedures: Essential System Services Quantities

[37] AEMO: guide-to-ancillary-services-in-the-national-electricity-market.pdf

- Largest Credible Supply Contingency;
- Distributed Photovoltaic (DPV), and
- any other factors that AEMO determines necessary to accurately predict frequency performance for system operations.

System Inertia is provided by online synchronous generation, synchronous condensers, and synchronous motors.[38]

While the concept of virtual synchronous Inertia is receiving attention, the provision of such services from BESS is presently not covered by the ESM Rules and AEMO's operational practices. Instead, the WEM relies on sufficient rotational Inertia from synchronous generators to maintain the RoCoF Safe Limit during the inertial response time. If a gap in RCS is identified AEMO can direct synchronous generation to ensure that the RoCoF Safe Limit is not exceeded.

To assess the system's frequency performance following Credible Contingency Events, high-resolution frequency measurements captured by high-speed data recording equipment for six significant events in the SWIS were considered in the Review. These events were selected based on their potential to cause noticeable frequency disturbances and, for each event, the frequency nadir and RoCoF were determined.

Figure 11 below provides an example of the frequency response and recovery for one of these events.[39] The example (likely to be the result of a trip of a single generating unit of around 300 MW) creates a frequency nadir around 4 seconds after onset of the event. Subsequently there is a recovery of frequency to within the Normal Operating Frequency Band in less than 60 seconds. The response highlights a stable arrest of frequency decline with a limited RoCoF, followed by a stable recovery.

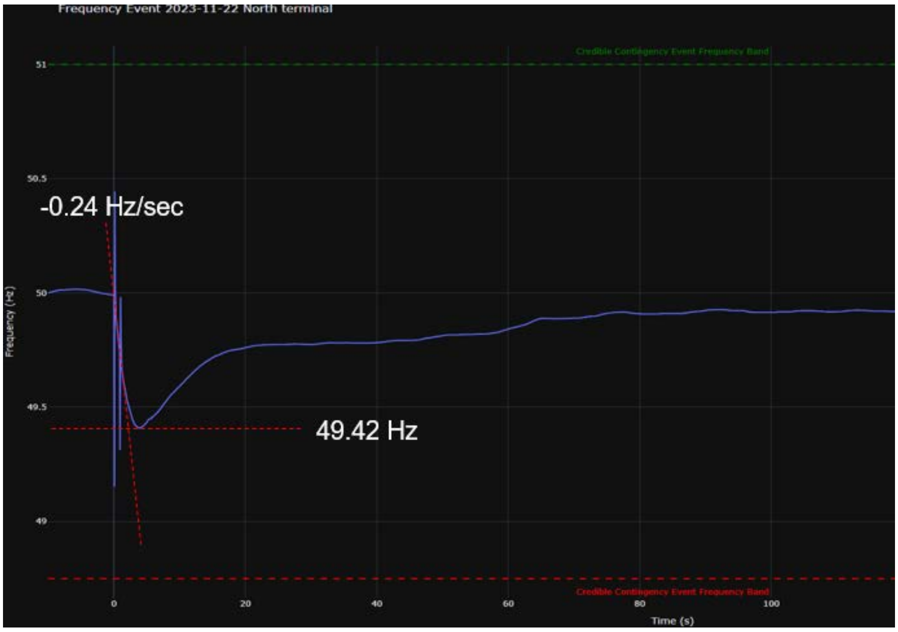

Figure 11: WEM Frequency response following a Credible Contingency Event on 22 November 2023

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[38] In the WEM inertia is procured in the form of RoCoF Control Service.

[39] The calculated RoCoF, frequency nadir and the Credible Contingency Event Frequency Band are highlighted in the figure for reference

Appendix B. Frequency management in other jurisdictions

ESS, such as Contingency Reserve or Regulation, are used in all modern power systems to ensure quality and security of electrical supply to consumers. While they serve a similar purpose, the form, quantities selected, methods of procurement, and means of settlement are shaped by the power system and market arrangements they are designed for.

To gain further insights into efficiencies and effectiveness of other forms of service arrangements, this Review included a comparison of the WEM FCESS arrangements with:

- the NEM;
- Ireland, operated by EirGrid and System Operator Northern Ireland (SONI) and
- New Zealand's electricity system operated by Transpower.

Each selected jurisdiction is representative of a modern power system, with well-established market frameworks and practices for managing frequency control essential system services. All three have a unique system demand, energy mix, and level of renewable penetration adapted to and/or a result of their geography and social factors. Table 11 below, outlines the general characteristics of each electricity systems for comparison.

Table 11: Comparison of electrical system characteristics

	WEM	Ireland	New Zealand	NEM
System Demand (GW)	4.2	6.8	7.0	33.4
Variable Renewable capacity (percent)	35	40	8	34
Synchronous generation (percent)	64	47	88	61
Market structure	Capacity	Capacity	Energy	Energy
Interconnection to other systems (GW)	none	1.0 (UK)	none[2]	none
Installed DPV (GW)	2.4	0.4	0.3	22

[1]Generation is shown as percentage of total installed capacity

[2]Not including the 1.4 GW rated North-South Island HVDC interconnection

The unique combination of electrical system characteristics shapes the types and quantities of ESS that are procured in each jurisdiction, as well as how they are set and procured. The electrical characteristics and specifications related to each jurisdiction's electricity network are summarised below in Table 12

Table 12: Characteristics of frequency operating standards of other jurisdictions

	WEM	Ireland	New Zealand	NEM
Normal frequency band[1] (Hz)	±0.2	±0.1	±0.2	±0.15
Largest Credible Supply Contingency (MW)	510	500	520	750
Contingency frequency band[1] (Hz)	-1.25/+1	±1	±0.75	±1
Max Contingency Reserve Raise (MW)	460	378	400/125[2]	750
Max Contingency Reserve Lower (MW)	-165	-158	-150	-400
RoCoF limit (Hz/sec)	0.5	1	1.2	1
Max Regulation Raise (MW)[3]	110	125	30[4]	220
Max Regulation Lower (MW)[3]	110	125	30[4]	210

[1] All compared systems operate a normal frequency of 50 Hz

[2] Contingency Reserve Raise is procured separately for each of the North and South Island of New Zealand

[3] Regulation may be procured in excess of the indicated amounts if required by the operator

[4] Services procured are for the purpose of correcting Area Control Error rather than frequency regulation

The following ten observations offer some insights into how these other electricity markets manage their essential service requirements, and outlines where there may be opportunities for improvement for the WEM. [40]

B.1 Single Contingency and Regulation Markets

Of the jurisdiction's reviewed, only the WEM has a single Contingency Reserve Raise and a single Contingency Reserve Lower market, that differentiates service offers by the speed of response[41] of the provider.

The NEM, Ireland, and New Zealand have separate markets differentiated by the time of response. The NEM for example has a very fast frequency response market for a one second response and a fast frequency response market for six seconds response, meaning that it is relatively simpler to procure the right service. The smaller shallow market in the WEM means that there is not enough competition for multiple markets, but the single market for each type of service creates more complexity in dispatch.

The jurisdictional comparison indicates that there may be value in considering whether the aggregated procurement of Contingency Reserve Raise from Facilities with different Speed Factors in a single market is accurate i.e., whether the summation of Contingency Reserve Raise

[40] Publicly available information was sourced to undertake the jurisdictional comparison.

[41] For the WEM AEMO defines a Facility Speed Factor an accreditation parameter that used to specify a facility's capability to provided Contingency Reserve Raise services. Facility Speed Factors can range from 0.2 seconds (fastest) to 15 seconds (slowest). The Facility Speed Factors reflects the time to deliver full CRR after a frequency excursions is detected.

provided by multiple generators, each with different Performance Factors, is representative of the actual requirements.

B.2 Mandatory Primary Frequency Response

All jurisdictions mandate narrow banded droop-based PFR from all generating facilities, subject to energy availability. This provides two potential benefits:

(a) support of frequency regulation; and

(b) support of contingency response.

The benefits of MPFR for frequency regulation are evident from the improvements in frequency performance in the NEM following the introduction of MPFR in 2019. In New Zealand, provision of PFR is the reason very little Regulation services are procured, other than for the correction of ACE.[42]

In New Zealand, hydroelectric generation is dispatched at 80% capacity, which retains significant headroom across the north and south islands. In the case of credible contingencies any MPFR outside of dispatched Contingency Reserve Raise will only add to stabilising the frequency.

Ireland also implements MPFR, although the impact of this is not transparent based on observed frequency performance. Given the minimum number of synchronous plant required to be online in Ireland, it is highly likely that there will be a positive impact on frequency, as generators are generally dispatched at minimum or low operating levels.

While MPFR is also an obligation in the WEM it may have limited impact on Regulation and Contingency responses due to operational challenges, including:

- frequent lack of headroom available to online synchronous generators that are not already enabled for Contingency Reserve Raise, during peak demand; and
- many synchronous generators often decommit when system demand is low to avoid running at high turn down ratios where thermal generation is less efficient and uses more fuel.

B.3 Minimum synchronous generation

In the NEM and Ireland minimum synchronous generation requirements are mandated for system strength purposes, and facilities are often dispatched at minimum generation levels leaving significant headroom.

To manage system strength across the NEM, there are operational requirements to retain a minimum number of synchronous generators online within each region of the NEM at all times.[43]

EirGrid also applies a minimum synchronous generator requirement for Ireland - at least seven in the Irish system - and five in the Northern Irish network. This is one of the main reasons for the amount of PFR that is available in the system to support frequency control. Similarly, the mandated synchronous generation also ensures that certain level of system inertia is always available within these two systems.

Transpower does not have a minimum number of synchronous generators that must be online because 80% of the fleet consists of synchronous machines.

[42] Area Control Error (ACE) is a key signal in power system control, specifically in AGC. It represents the difference between a control area's actual and scheduled power exchange with neighbouring areas, adjusted for frequency deviations. ACE is used to maintain grid stability by ensuring that generation matches demand within a control area and that scheduled power exchanges with other areas are maintained.

[43] This includes twelve generators in Queensland, seven in NSW, one in South Australia (when all four synchronous condensers are operating), and eight in Victoria

Similarly, the WEM has a minimum number of synchronous generators required in particular regions of the SWIS to manage System Strength. System Inertia

Both the WEM and New Zealand consider system inertia when determining the required quantities of Contingency Reserve Raise, optimising the quantity of contingency reserves procured to arrest frequency falls within the Credible Contingency Event Frequency Band, based on the anticipated RoCoF.

The NEM also uses an inertia aware factor during dispatch to multiply the required Contingency Reserve Raise by. Ireland does not consider this dynamically, but maintains a minimum level of inertia that is considered a safe limit to comply with statutory requirements for RoCoF.

On the 9 October the Australian Energy Market Commission (AEMC) announced its final determination not to create a new, real-time trading market for inertia. The decision concludes that existing system security frameworks, recently enhanced by the AEMC, are sufficient and flexible to manage the grid's stability efficiently for the foreseeable future[44].

B.4 Synthetic Inertia

The Australian Renewable Energy Agency (ARENA) funded trials at the Hornsdale Power Reserve identified that, a grid-forming BESS rated at 150 MW and located in South Australia, could provide as much as 2,000 MW.s of equivalent Inertia.[45] Similarly, industry trials in Ireland suggested that a 50 MW BESS could potentially provide as much dynamic response as a 550 MVA steam turbine.[46] Additionally, the UK's National Energy System Operator's Pathfinder project has already procured synthetic Inertia to meet future grid demands, subject to the contracted facilities meeting the System Operator's technical requirements.[47]

However, synthetic Inertia provided by BESS remains an area of investigation by many system operators rather than common practice. This is also the case in Australia, where projects such as the 2024 ARENA funded synthetic Inertia trials of the Transgrid Wallgrove BESS indicated some success supplying an Inertia-like response, albeit at the cost of potentially reduced fault-ride through capability.[48]

AEMO has also released advice on how synthetic Inertia could be assessed. [49] However, as such trials are ongoing, consideration of how Inertia from BESS could be part of a future ESS portfolio requires further investigation.

B.5 RoCoF Limits

Other jurisdictions set the maximum RoCoF at 1.0 Hz per second (for the first 0.5 seconds). As the WEM currently allows for only half this rate, the RoCoF Safe Limits defined in the FOS for the WEM appear to be set very conservatively when compared to other jurisdictions.

The more stringent RoCoF Safe Limits applied in the WEM are a precautionary measure that has a notable impact on the procurement of the quantities of Contingency Reserve Raise services.

With a more limited decline in system frequency following the Largest Credible Supply Contingency, the amount of Contingency Reserve Raise needed to remain within the Credible Contingency Event Frequency Band following the inertial response period is less.

[44] AEMC decides against new inertia market: costs outweigh benefits while existing reforms take hold | AEMC

[45] ARENA Hornsdale Power Reserve Expansion Project

[46] Australia Institute Inertia and system strength in the National Electricity Market

[47] National Grid ESO: Pathfinder Phase 3 Technical Performance Requirements

[48] TransGrid-Wallgrove-Battery-Flagship-Report.pdf

[49] AEMO Inertia requirements methodology

If the RoCoF Safe Limit were to be increased beyond the current safe limit, this would likely increase the quantities of higher Performance Factor Contingency Reserve Raise required to achieve compliance in some instances.

The largest RoCoF value set in other jurisdictions appears to be aligned with the minimum mandated RoCoF withstand capability of generating facilities connected to each network. The mandated performance requirement is generally around 1.0 Hz per second or as much as 4 Hz per second in the first 250 ms. This is also the case in the WEM.

B.6 Largest Credible Supply Contingency

In all jurisdictions considered, the quantities of Contingency Reserve Raise procured appear to be a product of the Largest Credible Supply Contingency, Load Relief, and System Inertia.

The WEM has a comparatively large Largest Credible Supply Contingency for a system with 4.2 GW of peak demand.

Peak demand in both New Zealand and Ireland is approximately 50% larger than in the WEM, however the Largest Credible Supply Contingency is approximately the same, around 500 MW.

This means that the WEM must carry more Contingency Reserve relative to the system demand. The Largest Credible Supply Contingency in the WEM is a result of a single contingency being able to disconnect multiple generating Facilities, as well as the introduction of fast responding BESS that can support larger contingencies.

In the other jurisdictions, the Largest Credible Supply Contingency is defined by the single largest generator loss. The loss of the HVDC bipole in New Zealand is considered non-credible and for such large excursions Under Frequency Load Shedding is triggered to arrest decline in frequency rather than Contingency Reserves only.

In addition to more reserve requirements, relative to demand, a further drawback of the increased Largest Credible Supply Contingency in the WEM is that the larger contingencies also create a higher RoCoF, which then requires more Inertia to be present in the system to maintain the RoCoF Safe Limit prescribed in the ESM Rules.

It is not clear whether the Largest Credible Supply Contingency was intentionally limited in New Zealand and Ireland to manage system security.However, in the NEM there is a cap of 750 MW on the largest loss of supply permitted as a credible contingency. This is intentional to limit the quantity of Contingency Reserve Raise required. In New South Wales there is a further restriction imposed (700 MW) of the Largest Credible Supply Contingency, this being the largest single generator in that region.

WEMDE allows for limiting of the Largest Credible Supply Contingency to reduce the quantities and costs of Contingency Reserve Raise and does reduce Largest Credible Supply Contingency regularly to manage the cost of Contingency Reserve Raise against size of the Largest Credible Supply Contingency, when the RoCoF Safe Limit does not present an issue.

Due to differences in the DFCM and RTFS, when the RTFS identifies a breach of the RoCoF Safe Limit for a Credible Contingency Event, it triggers an AEMO directive to source additional RCS from Market Participants to reduce the severity of the frequency deviation and restore the system to a Secure Operating State. AEMO will direct specific registered Facilities to provide the necessary Inertia that will slow down the change in frequency and prevent further system instability. These directions override the WEMDE solution to reduce Contingency Reserve Raise costs.

B.7 Load Relief

Load relief is a factor applied to determine the amount of Contingency Reserve Raise quantities. In the WEM this is 2% meaning a 2% reduction in system demand for every % reduction in system frequency.

In the NEM, this factor has been reduced to 0.5% following a series of system trials conducted during 2019.

EirGrid, while not explicitly confirming the quantity of load relief applied in the all-island system, appears to also use a quantity of around 2%, based on the amount of contingency reserve procured (75% Largest Credible Supply Contingency) and the emergency frequency operating band of 49 – 51 Hz.

There appears to be a similar approach in New Zealand where the amount of instantaneous reserve is around 75% of the largest generator contingency, with a similar contingency frequency operating band, all of which suggests around 2% load relief is allowed for. This is also suggested by the frequency bias Transpower applies to ACE corrections.

B.8 Regulation

The performance of frequency in the WEM is exceptional, remaining within the Normal Operating Frequency Band for >99.8% of the time.

The NEM has reported a similarly high level of performance on the mainland, with a lower, yet still FOS compliant response in Tasmania. As noted above the introduction of mandatory PFR in 2019 resulted in improvements in NEM frequency performance.

New Zealand has a wider normal operating band and a generation fleet that comprises around 80% synchronous plant that provide PFR. Consequently, frequency performance in New Zealand is exceptional to the point where Transpower does not procure specific services for frequency regulation, but only to correct ACE.

In Ireland the high share of variable renewable generation has generally resulted in lower levels of frequency deviation than those recorded in the other jurisdictions. Over the past years, the electrical frequency in Ireland remained within the normal operating band for around 98.7% of the time.

While there is incomplete documentation as to how quantities of frequency regulation are set in each jurisdiction it appears to be largely determined based on historical quantities, observed requirements, and system trials. This is similar in the WEM, where there is no clear indication how quantities have been derived.

When comparing the level of performance of frequency regulation in each jurisdiction, the amount of regulation procured, the likely presence of PFR with sufficient headroom, as well as the level of renewable penetration, it appears that WEM quantities are not unreasonably set. However, further assessment of WEM regulation performance should consider trials that reduce the quantities of Regulation procured and observe performance.

B.9 Future Frequency Services

The observed and anticipated levels of renewable (non-synchronous) generation operating in each jurisdiction have a direct influence on the nature and types of required frequency ESS.

Ireland with its very high penetration of wind generation also includes frequency ESS to manage high active power ramping rates and renewable generation forecasting errors. The potential for variable renewable generation to create large power swings was also observed in the WEM during September of 2022, when DPV production fluctuations combined with some incorrect generation dispatches resulted in some significant frequency swings over the period of several hours.

In New Zealand presently there are no minimum inertia levels to be managed, however, the Transmission System Operator anticipates that when instantaneous variable renewable penetration levels reach 50% this will become necessary. At present, the instantaneous penetration has been around 80%.

The NEM has also moved to managing minimum inertia levels, but the present course is to procure and manage this in a similar manner to that of system strength provision, in which AEMO specifies the anticipated shortfalls, and the regional transmission network service provider will procure this.

While the WEM appears to be well placed based on the performance of the system frequency, new phenomena or requirements as renewable generation levels increase may need to be considered and new services introduced.

B.10 Contracts and markets

The WEM and the NEM have a fully co-optimised energy and FCESS market based on constrained economic dispatch. New Zealand also co-optimises energy and ESS, although at a much less granular time frame using a 30-minute clearing market.

Ireland still contracts for ESS. However, the Irish Transmission System Operator is currently consulting on reforms to the Irish services arrangements that will also see it transition to a market based procurement model by around 2026. The format and structure of the latter is not yet known.

In conclusion there appears to be a recognition that a market based approach to generate competitive tension works efficiently for the provision of ESS. This requires a minimum volume of service offers, and likely will create different classes of services providers depending on the technology from which the service is being sourced.

B.11 Learning from others

While energy consumption patterns, renewable penetration levels, uptake of DER, and geographical dimensions may differ between jurisdictions, all modern power systems share a purpose, of secure, reliable and economic supply of energy to consumers and most jurisdictions are making changes to their ESS regimes based on increasing renewables.

The three systems compared with the WEM are different in many ways, but also share many common arrangements, including how each manages frequency control services. Differentiators and commonalities between the reviewed markets and the WEM include:

- broad consideration of MPFR in quantifying Regulation Raise and Regulation Lower in other jurisdictions.
- other jurisdictions do not have markets for Inertia (RoCoF Control Service), instead minimum levels are set based on maximum RoCoF for Largest Credible Supply Contingency, or else achieved by setting synchronous generation levels for other service requirements such as system strength, and these are set outside of the market e.g. Transmission Network Service Providers procured in the NEM.
- time differentiated Contingency Reserve Raise services rather than a single performance differentiated market.
- all set minimum synchronous generation levels for system security.
- RoCoF Safe Limits in other jurisdictions that are more generally aligned with known synchronous generator technology capability RoCoF withstand of 1 Hz per second. However, it is noted that capability can vary from plant to plant and should be considered ahead of implementation.

Appendix C. Questions raised by ESSFRWG members

AEMO has responded to concerns raised by some of the ESSFRWG members with the proposal to increase the RoCoF Safe Limit, considering that it has not been observed or tested in real time. AEMO has undertaken jurisdictional comparisons, various types of modelling and analysed potential outcomes to complete its due diligence, with all outcomes suggesting that generators can typically ride through the proposed amended RoCoF Safe Limit.

An extended consultation period is provided, and stakeholders are encouraged to engage and share any evidence that would suggest endangerment to existing Facilities or suggest capabilities differ from those required under the Technical Rules, ESM Rules or the ESS accreditation process. This evidence will be assessed in informing the final outcomes of this Review.

Below is a list of queries from ESSFRWG members and responses from AEMO.

Noting that with the current 0.5Hz/s limit, it is understood that the SWIS has only observed 0.3Hz/s. What does AEMO expected to be the “likely” RoCoF level that the SWIS will operate at following the change in the RoCoF Safe Limit?

The SWIS has observed RoCoF of 0.46 Hz/s from a real-life power system event. This occurred at 11:26 on 02/01/2021 due to a forced outage of the NBT-YDT-TST-ENT91 line. WARRADARGE_WF1 and YANDIN_WF1 tripped resulting in a loss of approximately 308MW. More information can be found under Dispatch Advisory ID 207686. It is worth noting that this was under a different market arrangement prior to the implementation of the RoCoF Safe Limit. However, it is still a notable event and an example of capabilities of the Power System.

Should the proposed amended RoCoF Safe Limit proceed, WEMDE is expected keep the RoCoF level of the power system to 0.75 Hz/s or below for a Credible Contingency Event, provided there are no shortfalls of Contingency Reserve.

How often does AEMO consider the SWIS could hit the 0.75Hz/s RoCoF and if an event were to occur, what is the likely duration of an event?

If the RoCoF Safe Limit is set to 0.75 Hz/s, WEMDE is designed to balance the economic efficiency while maintaining the RoCoF to 0.75 Hz/s or below. The ‘best’ solution may be to operate the power system at a high inertia level, which could result in low RoCoF, should the largest contingency take place; or a lower inertia level with higher RoCoF, but no higher than 0.75 Hz/s.

AEMO has observed a range of power system events with varying duration. In general, if a Credible Contingency Event is due to a fault on the Network, the Network Operator has the obligation to clear the events within the required clearance times (see Table 2.10 and 2.11 in the Technical Rules).

If a Credible Contingency Event is due to a Facility tripping (with no fault on the Network), the frequency could decay for seconds before recovery. However, it is important to note that, the Rate of Change of Frequency is not linear following a disturbance. The rate of change is typically the fastest immediately following a disturbance and slows over the remaining period of the decay.

The frequency however is not expected to decay beyond the requirements in Appendix 13 of ESM Rules or trigger Under Frequency Load Shedding (UFLS) first stage at 48.75 Hz for a Credible Contingency Event.

Can AEMO provide clarity on the expected accuracy of AEMO’s modelling (forecast vs actual) for RoCoF outcomes?

AEMO verified the proposed amended RoCoF Safe Limit in the DFCM, which is the same model that AEMO uses to provide input into WEMDE in real-time operations currently. It shows that with the proposed amended RoCoF Safe Limit, frequency can be maintained between the required Credible Contingency Event Frequency Band.

Information on other modelled outcomes, specifically in relation to Facility Performance Factors and Largest Credible Supply Contingency / Largest Credible Load Contingency sizes can be found in slides 12 to 16 of the [24 July ESSFRWG papers.]

Can AEMO provide clarity on modelled relationships of the ESS markets (i.e. if the model solves so that there is high inertia, does WEMDE allow for lower levels of Contingency Reserve Lower – or are the ESS markets each solved independently of the other)?

If they are independently solved, can AEMO undertake further analysis to understand possible outcomes where the system is dispatched at the lower end of each of the markets – i.e. low Inertia and low Contingency Reserve Lower, and if a contingency event were to then occur, what would be the final outcome in these situations?

All markets are co-optimised together. In practice, as the offered price of all RCS is zero, WEMDE dispatches all available quantities of RoCoF, and so there is no trade-off at dispatch time between RCS and any other service.

To the extent there is a trade-off, it is based on unit commitment, which is outside of WEMDE's control. In theory, if synthetic Inertia becomes available, WEMDE could start co-optimising RCS against other services, but this would require algorithm changes to properly account for headroom requirements to provide RCS from Inverter Based Resources.

Is AEMO reviewing load shedding limits to support generators and SWIS in low Inertia scenario?

- Assuming only tripping load is effective within the first 500ms to 1s from contingency event, is AEMO considering adjustments to UFLS schemes?

AEMO considered the current UFLS under section 2.4 of the Technical Rules in its review of the RoCoF Safe Limit. With the measurement period of 500 ms, the positive RoCoF Safe Limit must not exceed 2 Hz/s and the negative RoCoF must not exceed 2.5 Hz/s, so as not to breach the frequency requirements of Appendix 13 of the ESM Rule or trigger first stage UFLS at 48.75 Hz.

Will frequency be allowed to dip further before ESS becomes effective, or will early load shedding thresholds be maintained to protect system stability?

AEMO verified the proposed amended RoCoF Safe Limit in the DFCM, which contains a full set of pre-calculated possible operational conditions for the WEM and is one of the inputs into WEMDE. Provided there are no shortfalls of Contingency Reserve, the power system is not expected to violate the Credible Contingency Event Frequency Band (48.75 Hz) for power system conditions as strenuous as:

- underlying loads between 1,400 MW and 4,200 MW,
- System Inertia between 5,000 MW.s and 30,000 MW.s, and
- supply contingency up to 650 MW.

For context, the current records since November 2023 are 1,654 MW of underlying load (load + DPV), 10,957 MW.s of min System Inertia and 453 MW of supply contingency.

Noting that frequency decay during contingency events relies solely on System Inertia in the first second (as ESS is ineffective during this initial period); with the lower Inertia it would be expected that frequency will dip lower and at a faster rate, although it may recover more quickly due to the lower energy requirement. Can AEMO please provide information on expected frequency decay outcomes

- In a critical event (worst-case scenario); and
- In a typical event (e.g., single unit trip, occurring approximately 15–20 times per year).

Verifications in the DCFM show that frequency is expected to remain within the Contingency Event Frequency Band following a Credible Contingency Event.

There is no limit to what a Non-Credible Contingency Event would entail and how that would affect frequency decay. UFLS is expected to operate to assist with frequency recovery in these cases.

With reduced Inertia, grid frequency will change more rapidly in response to both small and large disturbances, which affects all synchronous generators - causing more frequent speed changes (unknown effect in long term). PFR is expected to act within 1–3 seconds, operating around the frequency deadband. This increases demand on turbine governors, and we have already observed mechanical linkage issues due to increased PFR activity, particularly during low-load periods.

- Should we expect further decay in frequency stability under low Inertia conditions?

With a RoCoF Safe Limit of 0.75 Hz/s, AEMO does not anticipate the frequency to decay beyond the requirements of Appendix 13 of the ESM Rules or trigger first stage UFLS at 48.75 Hz for a Credible Contingency Event under low Inertia conditions.

With low Inertia and damping, synchronous generators may swing against each other even during minor disturbances. This is more likely during extremely low load conditions in the SWIS. Has this been assessed as part of the proposed change, and what are the risks that this presents to facilities and the SWIS?

Western Power is responsible for monitoring and managing the network stability during low load conditions, including Transient Rotor Angle Stability (clause 2.2.7 of the Technical Rules) and Oscillatory Rotor Angle Stability (clause 2.2.8 of the Technical Rules).

However, the potential impact and requirements of System Strength, especially during low Load conditions, are being studied by AEMO separately under the Engineering Road Map. This is discussed in Chapter 6 of 2025 WEM ESOO and throughout the Engineering Road Map.

We consider that with lower Intertia, the kinetic energy from synchronous generators will be used differently. Further, with fewer synchronous machines online, the remaining generators will likely be required to contribute more kinetic energy over a longer duration.

This is because they sustain the inertial response until active power injection becomes available—either from energy storage systems (ESS) or PFR. This extended reliance on the remaining synchronous units can increase mechanical stress and may require re-evaluation to ensure equipment longevity. We consider it is important to note that impacted synchronous generators will also be impacted during normal operation as <1s response coming only from Inertia.

- Can AEMO provide a model or evaluation of kinetic energy injection from a typical unit (e.g., based on MPS), both before and after the RoCoF limit change, for typical operations during low-load troughs and critical contingencies?

Unfortunately this is not information available to AEMO. Many jurisdictions, including the NEM, operate their power systems to 1 Hz/s or above. OEMs with synchronous generators in those jurisdictions are better placed to provide this information.

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