Frequency Contribution Factors Procedure

Final Report – Standard consultation for the National Electricity Market

Published: 1 June 2023

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New South Wales | Queensland | South Australia | Victoria | Australian Capital Territory | Tasmania | Western Australia

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Executive summary

The publication of this final report concludes the consultation conducted by AEMO to develop and publish a new Frequency Contribution Factors Procedure (**FCFP**) (the **proposal**) under the National Electricity Rules (**NER**).

AEMO thanks everyone who participated in this consultation, which was undertaken as required by NER 11.152.3, following the standard consultation procedure in NER 8.9.2.

This final report details the conclusions reached by AEMO in determining the contents of the FCFP. Key departures from the draft report and draft FCFP include:

- The length of the historical performance period used in the calculation of default contribution factors (**DCFs**) was reduced to 7 days from 28 days, with measures to determine DCFs when there is insufficient historical data, to balance more reflective DCFs with reliability of the calculation.
- The cap on the requirement for corrective response (**RCR**) has been removed. AEMO agreed that a cap is not required to limit market risk because AEMO can recalculate the RCR when bad data causes an incorrectly high RCR.
- When AEMO is unable to calculate and publish the contribution factors (**CFs**) for a trading interval within the time required by NER 3.15.6AA(k)(1), the system will keep trying to access the input for a limited period of 30 minutes after the relevant trading interval, before defaulting to DCFs for Regulation FCAS cost recovery. This maximises the opportunity to use actual performance as the basis for recovery, while still determining and publishing the applicable factors in a timely manner.
- Provision for the Frequency Measure (**FM**) in a region to be taken from multiple sources, to ensure data is still available where the primary feed is either unavailable or experiencing quality issues.
- Four-second performance will be ignored where there is a misalignment between the frequency measure and frequency deviations, and frequency is outside the primary frequency control band (**PFCB**) in the opposite direction from the FM.
- Clarification on unit aggregation has been included, although the intent of the measures remains the same as the draft FCFP: Eligible units with appropriate metering that are aggregated must be in the same region and owned by the same financially responsible Market Participant of the same participant ID.

The FCFP will have effect under NER 3.15.6AA, which commences on 8 June 2025 under the National Electricity Amendment (Primary Frequency Response incentive arrangements) Rule 2022[1].

AEMO's final determination on the proposal is to make the Frequency Contribution Factors Procedure in the form published with this final report, with an effective date of **8 June 2025**. AEMO's existing Regulation FCAS Contribution Factor Procedure will be revoked with effect from the same date and replaced by the FCFP.

[1] Final determination and amending rule available on the Australian Energy Market Commission's website at https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements.

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1. Stakeholder consultation process

As required by National Electricity Rules (**NER**) 11.152.3, AEMO has consulted on the new Frequency Contribution Factors Procedure (**FCFP**) (the **proposal**) in accordance with the Standard rules consultation procedures in NER 8.9.2.

Note that this document uses terms defined in the NER, which are intended to have the same meanings. There is a glossary of additional terms and abbreviations in Appendix A.

AEMO's process and timeline for this consultation are outlined below.

Table 1 Consultation process and timeline

Consultation steps	Dates
Information workshop	19 September 2022
Consultation paper published	31 October 2022
Consultation briefing	4 November 2022
Submissions due on consultation paper	6 December 2022
Draft report published	7 February 2023
Consultation briefing	15 February 2023
Technical workshop	21 February 2023
Workshop on publication of data	28 February 2023
Submissions due on draft report	15 March 2023
Final report published	1 June 2023

AEMO's consultation webpage for the proposal at https://aemo.com.au/consultations/current-and-closed-consultations/frequency-contribution-factors-procedure contains all published papers and reports, written submissions, and other consultation documents or reference material (other than material identified as confidential).

In response to its consultation paper on the proposal, published on 31 October 2022, AEMO received four written submissions.

AEMO also held three briefings, one hosted by AEMO for all interested parties on 4 November 2022, one with the Clean Energy Council on 5 December 2022, and one with the Australian Energy Council on 7 November 2022.

AEMO considered the submissions and other relevant information in developing the draft report and draft determination on the proposal. The draft report and draft FCFP were published on 7 February 2023.

AEMO held a further briefing on 15 February 2023, followed by two technical workshops, one on 22 February 2023, the other on 28 February 2023. On 9 March 2023 AEMO published a list of questions and answers arising from the 28 February technical workshop.

In response to its draft report, AEMO received five written submissions.

AEMO thanks everyone who participated in this consultation, both in meetings and through written submissions. All feedback has been considered in preparing this final report.

2. Background

2.1. Context for this consultation

On 8 September 2022, the Australian Energy Market Commission (**AEMC**) published its final determination of the PFR incentives rule (**Rule**). The Rule provides enduring arrangements to support the control of power system frequency and incentivise plant behaviour that reduces the overall cost of frequency regulation during normal operation. For Market Participants to have sufficient certainty around the implementation of this new framework for the optimisation and development of their systems, the Rule requires AEMO to develop and publish the Frequency Contribution Factors Procedure (**FCFP**) by 8 June 2023, to take effect from 8 June 2025.

The FCFP will replace the Regulation FCAS Contribution Factor Procedure (made under NER 3.15.6A(k)), which currently determines how AEMO calculates the contribution factors (**CFs**) for recovering the cost of regulating raise and regulating lower market ancillary services (**Regulation FCAS**) in the national electricity market (**NEM**). These factors are intended to reflect the extent to which a Market Participant can be taken to have 'caused' the need for Regulation FCAS based on the negative performance of its facilities (where this can be measured), with the residual allocated to Market Customers based on energy consumption.

The FCFP will reflect significant changes introduced by the Rule for the recovery of Regulation FCAS costs, including the introduction of frequency performance payments (**FPP**) for Market Participants' eligible units where their primary frequency response (**PFR**) helps to reduce the frequency deviations (**FDs**) that would otherwise require the dispatch of Regulation FCAS.

2.2. NER requirements

AEMO is required to publish the FCFP under NER 11.152.3. The FCFP must include the content described in, and be consistent with the principles in, NER 3.15.6AA.

2.2.1. Content requirements

NER 3.15.6AA(g) requires the FCFP to include the following:

(g) *AEMO* must include in the frequency contribution factors procedure:

- (1) the criteria for determining whether an eligible unit has appropriate metering;
- (2) a formula that AEMO will use in each *trading interval* to calculate the measure of the need to raise or lower the *frequency* of the *power system*, in order to determine a contribution factor under paragraph (e), which:
  - (i) must be based on the *frequency* of the *power system* in the relevant *region* or *regions*;
  - (ii) must contain sufficient detail so that a *Cost Recovery Market Participant* can use it to estimate the need to raise or lower the *frequency* of the *power system* during each *trading interval*; and
  - (iii) may include parameters to be determined by *AEMO* from time to time to be applied to the different elements of the formula;
- (3) the methodology *AEMO* will use to determine a contribution factor to apply to an eligible unit which reflects the relevant *Cost Recovery Market Participant's* contribution to the deviation in *frequency* of the *power system*;
- (4) the methodology *AEMO* will use to determine default contribution factors to apply to an eligible unit:

(i) under paragraph (b) to determine the trading amount payable by a *Cost Recovery Market Participant* or paragraph (c), where it is impractical for *AEMO* to determine a contribution factor for that unit in a *trading interval* based on the data measured for that *trading interval* under subparagraph (f)(8);

(ii) for the allocation of costs of any *enabled regulating raise service* or *enabled regulating lower service* that was not used by *AEMO* in that *trading interval* under paragraph (d); and

(5) the data *AEMO* will use to calculate the contribution factor for an eligible unit with appropriate metering, which must include the unit's *active power* output or consumption and a measure of *frequency*, and may include:

(i) the *frequency* measured at the *connection point* for the eligible unit; and

(ii) any other data *AEMO* considers relevant.

(6) the methodology *AEMO* will use to determine:

(i) the requirement for corrective response under subparagraph (b)(1), which is a measure of the total volume in MW that contributed to reducing the deviation in *frequency* of the *power system*. This methodology may include parameters to be determined by *AEMO* from time to time to be applied in determining the requirement for corrective response; and

(ii) the usage under subparagraph (c)(1), which is the proportion of *enabled regulating raise service* or *regulating lower service* that contributed to reducing the deviation in *frequency* of the *power system*,

relevant to the *global market ancillary service requirement* or *local market ancillary service requirement* for the *regulating raise service* or *regulating lower service*; and

(7) the methodology *AEMO* will use to determine a reference trajectory in each *trading interval* for each eligible unit which has appropriate metering, which must be informed by:

(i) the *dispatch* target for a *scheduled generating unit*, *scheduled load*, *scheduled bidirectional unit* and *ancillary service unit* at the end of the previous *trading interval* and at the end of the relevant *trading interval*;

(ii) the *dispatch* level for a *semi-scheduled generating unit* at the end of the previous *trading interval* and at the end of the relevant *trading interval*; and

(iii) where practical, any information provided by a *Registered Participant* for a *non-scheduled generating unit* or *non-scheduled bidirectional unit* that relates to its expected trajectory over the *trading interval*,

and may be informed by any other factors *AEMO* considers relevant.

2.2.2. Principles for determining contribution factors

The FCFP should also give effect to the principles listed in NER 3.15.6AA(f):

(1) a negative contribution factor for an eligible unit should reflect the extent to which the unit contributed to increasing the deviation in *frequency* of the *power system*;

(2) a positive contribution factor for an eligible unit should reflect the extent to which the unit contributed to reducing the deviation in *frequency* of the *power system*;

(3) a contribution factor is a number between -1 and 1;

(4) the residual contribution factor for all eligible units that do not have appropriate metering must be equal across and within all classes of *Cost Recovery Market Participant*;

(5) separate contribution factors must be determined with respect to the contribution to the need to raise or lower the *frequency* of the *power system*;

(6) a contribution factor for each eligible unit must be determined by *AEMO* for every *trading interval* unless in *AEMO's* reasonable opinion it is impractical to do so, in which case *AEMO* must determine a default contribution factor;

(7) a contribution factor for each eligible unit applies for the *region* or *regions* relevant to the *global market ancillary service requirement* or *local market ancillary service requirement* for the *regulating raise service* or *regulating lower service*;

(8) a default contribution factor for an eligible unit must be determined based on historical data for that eligible unit unless in *AEMO's* reasonable opinion it is impractical to do so; and

(9) a default contribution factor must only be used in paragraph (b) to determine the *trading amount* payable by a *Cost Recovery Market Participant*.

2.3. The national electricity objective

Within the specific requirements of the NER applicable to the proposal, AEMO has sought to make a determination that is consistent with the national electricity objective (**NEO**) and, where more than one option can fulfil a specific NER requirement, to select the one best aligned with the NEO.

The NEO is expressed in section 7 of the National Electricity Law as:

to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system.

3. List of material issues

The key material issues raised in submissions to the draft report are listed in Table 2. This final report only discusses those issues. Please refer to the draft report for AEMO's consideration of issues arising during earlier stages of this consultation.

Table 2 List of material issues

No.	Issue	Raised by
1.	Measurement of Power System Frequency	Australian Energy Council (**AEC**), CS Energy & Shell Energy
2.	Frequency Measure	AEC, CS Energy & Shell Energy
3.	Default Contribution Factors	CS Energy & Shell Energy
4.	Requirement for Corrective Response	AEC, CS Energy & Shell Energy
5.	Usage	Shell Energy
6.	Reference Trajectories	AEC, CS Energy, Delta Electricity, Shell Energy
7.	Aggregated Dispatch Conformance	Shell Energy & Snowy Hydro
8.	AEMO Inability to Calculate and Publish Contribution Factors in a Reasonable Timeframe	AEC, CS Energy & Shell Energy

A detailed table of issues raised by stakeholders in written submissions to the draft report, together with AEMO's responses, is contained in Appendix B. Questions and responses from non-confidential meetings are published at https://aemo.com.au/consultations/current-and-closed-consultations/frequency-contribution-factors-procedure for the proposal.

Each material issue in Table 2 is discussed in Section 4.

4. Discussion of material issues

4.1. Measurement of Power System Frequency

4.1.1. Issue summary and submissions

AEMO concluded in the draft report that power system frequency should be determined regionally, as it would provide a Frequency Measure (**FM**) that is more closely aligned with what most local units are responding to and requires no adjustment when regional separation occurs. Compared with local measurements at each connection point, the cost and complexity of implementation would be significantly lower.

Three submissions addressed this issue.

Australian Energy Council (AEC)

> The AEC encourages AEMO to consider measuring frequency at more points than one per region. If additional geographic measurements were made, it would lessen the need to suspend payments where islanding does not align with a regional boundary.

CS Energy

> CS Energy supports the AEMO proposal to move from a single power system frequency measurement source to multiple power system frequency measurement sources located throughout the NEM capturing both regions and potential separation event outcomes. This level of redundancy should ensure that in the event of a failure or isolation from the primary power system frequency measurement source, a fail over would occur to an alternate power system frequency measurement source.

Shell Energy

> We support AEMO's proposal to move from a single central frequency measurement point to at least regional based measurement points. We also agree that measurement at each connection point in the power system would lead to an unsatisfactory level of costs and complexity which in this instance is unwarranted. However, we consider there would be benefit in measuring frequency based on key sub-regional locations as opposed to a single measurement point in each region. These key sub-regional locations could be defined based on historical points of line failure which resulted in generating units and potentially scheduled load providing primary frequency response (PFR) being electrically located in areas other than their nominal region. We offer the following initial frequency measurement points for AEMO's consideration.

Queensland	New South Wakes	Victoria	South Australia	Tasmania
South Pine	Sydney West	Thomastown	Torrens Island	George Town
Braemar	Armidale	Heywood	Davenport	Chapel Street
Calvale	Upper Tumut	Dederang		
Nebo				

> Units would be allocated to each frequency measurement point based on their relative strength of electrical connection to each measurement point under system normal conditions. The allocation database should also contain sufficient flexibility to allow temporary reassignment of a generating unit or scheduled load to an alternative measurement point, if required. Non-Scheduled load and generation, (what is currently defined as the residual), would remain allocated to its primary regional frequency reference point at all times.
>
> Whilst this is nine additional frequency measurement points compared to AEMO's proposal, we consider setting the measurement points on a more granular basis in the initial systems change process offers a cost effective outcome that provides higher accuracy resilience under a wide range of power system operating conditions and one that is preferable to AEMO's proposed solution to not pay generating units or scheduled load for the provision of PFR when an electrical islanding event does not align with the regional boundaries. This proposed amendment to AEMO's proposal would provide clear incentives to PFR providers to continue to provide the PFR even during challenging power system operating conditions. AEMO's proposal would incentivise energy storage systems or schedule load to remove service provision under some power system operating conditions. Shell Energy does not support AEMO's proposal to not provide FPPs in the event that an electrical islanding event is not aligned with a regional boundary.

> In the event of a SCADA data failure which impacted one of the frequency measuring points, the affected measuring point would default to the electrically closest alternative measuring point. This default failover provision could be set and communicated to participants in advance. This amendment to AEMO's proposal would also provide additional benefit in facilitating AEMO implementation of Recommendation 2 from the Final Report – Queensland and South Australia system separation on 25 August 2018 dated 10 January 2019, to automate reconfiguring of AEMO's systems including AGC and NEMDE after separation and large system events. Post this event on 28 August 2018, AEMO's systems continued to dispatch units based on an incorrect reference frequency and inter-regional network status in the Queensland and South Australia regions for what the Report regarded was an unacceptable time period from a power system security perspective.

4.1.2. AEMO's assessment

In specifying suitable points for determining the FM, AEMO is conscious of the need to consider and strike an appropriate balance between the benefits of multiple measurement locations per region, and the complexity and cost associated with the different ways this can be achieved. AEMO's assessment has considered the following key factors:

- There is no material difference between frequency at different locations at a 4-second resolution within a region when the power system is operating in a steady state.
- Generation can be allocated to pre-defined sub-regional frequency measurements as the location of generators is fixed.
- For regional load, however, linking sub-regional frequency measurements to the correct sub-regions would require constant monitoring of transmission (and sometimes distribution) line flows.
- AEMO currently does not have sufficiently accurate data for this purpose. The necessary monitoring of transmission and distribution line flows adds considerable complexity and cost due to the extensive system and process changes that would be required from both AEMO and network service providers, which does not appear justified given the relative infrequency of sub-regional islanding.
- Given the inherent disparity in accuracy and quality among various measurements within a given region, applying an averaging methodology to ascertain frequency deviations is not considered appropriate.

4.1.3. AEMO's conclusion

AEMO accepts the AEC's suggestion that, to ensure redundancy, the frequency measurements should, when feasible, be derived from multiple sources within a given region. This arrangement permits the data pre-processing system to transition to an alternate data feed in instances where the primary feed is either unavailable or experiencing quality issues.

4.2. Frequency Measure

4.2.1. Issue summary and submissions

AEMO concluded in the draft report that the FM in the draft FCFP appears to be fit for purpose.

Additional conditions were identified where the FM is considered not a reliable measure of the need to raise or lower the frequency of the power system. In these cases, there would be no FPPs (for raise, lower, or both, depending on the condition) and all Regulation FCAS costs would be recovered based on Default Contribution Factors (**DCFs**).

Three submissions were received on this issue.

AEC

The design always assumed AEMO would need to perform a degree of filtering/averaging of the raw frequency input, and the AEC is pleased that AEMO has performed analysis to support its proposed exponential moving average approach. Whilst this appears the best approach from the information to hand, this is an area also worthy of regular post-implementation review as discussed above.

Given that it is a moving average, there will be instants where the actual frequency has crossed to one side of 50Hz whilst the measure is still on the other side. Those DUIDs who have responded very quickly to that frequency change will be anomalously briefly penalised by the measure. AEMO has argued that this anomaly has low materiality, which the AEC does not dispute. However, as a matter of principle, AEMO should consider whether it is appropriate and feasible to at least zero the penalty for these instants.

CS Energy

CS Energy is supportive of AEMO's proposal to utilise an exponential weighted moving average (**EMA**) to determine the FM. AEMO's proposal to incorporate a calculation dead band of 49,990 – 50.010 Hz may result in overlooking actual PFR supplied by providers that in effect is maintaining the power system frequency within the dead band.

Shell Energy

Shell Energy is supportive of AEMO's proposal to use an EMA for the FM based on the analysis as presented in the draft report. Whilst acknowledging the proposed EMA does not result in perfectly accurate measurement under all power system conditions, based on AEMO analysis it remains the best of the range of options considered. Notwithstanding, we recommend that the procedure contain clear provisions for regular annual review of the proposed EMA method comparing it to alternative methods, in addition to the proposed review of the EMA smoothing factor key inputs.

Shell Energy also notes AEMO's proposal to include secondary condition benchmarks to deal with the issue as noted by AEMO, that in some instances, the proposed EMA may not accurately reflect the need for PFR or the correct direction of its provision. We are supportive of such secondary conditions. However, we do have some concerns that AEMO proposal to implement a calculation dead band between 49.990 and 50.010 hertz may result in undervaluing the actual amount of PFR being supplied. The power system could remain within this boundary simply because of the level of PFR actually supplied at that point in time, yet no FPP would be made.

We would also like to raise what we consider to be a third secondary condition for AEMO's consideration. Data provided to AEMO technical workshop on 21 February 2023[2], indicated that at times the proposed EMA measure is misaligned with actual power system frequency which is the physical metric that generating units or scheduled loads providing PFR respond to. This results in a financial distortion of the physical signals which incentivise the provision of PFR. This is similar to the current issue in the CF calculation where at times the Frequency Indicator (FI) is misaligned with power system frequency. Currently where FI and power system frequency are misaligned the trading interval is removed from the CF calculation. We recommend that the draft procedure be amended to record a Null value for those 4 second intervals when misalignment between the frequency measure and measured power system frequency occur.

4.2.2. AEMO's assessment

There are several issues arising from the submissions that AEMO will address separately.

Exponential Weighted Moving Average (EMA)

AEMO demonstrated in the draft report that EMA (compared to other smoothing alternatives such as a simple moving average or sum of moving averages) provides the best trade-off between different aspects of a suitable FM. Additionally, the EMA provides sufficient flexibility through its smoothing factor (configurable parameter) that can be modified in future, if required.

Annual Review of EMA Method

Shell Energy proposed a regular annual review of the proposed EMA method comparing it to alternative methods, in addition to the proposed review of the EMA smoothing factor key inputs.

[2] AEMO Presentation 21/2/23 - Slide 7 - Primary Frequency Response Incentives Rule Change (aemo.com.au).

AEMO does not consider that the overhead associated with a mandated annual review of the EMA method is warranted, noting that:

- A review of the EMA smoothing factor α can be conducted at any time, and a change made expeditiously if a preferable value is identified.
- Given this inbuilt flexibility, a need to review the underlying methodology itself is not expected to arise frequently. If a need is identified in future, it can be undertaken as required, with any proposed change being subject to the rules consultation procedures.

Secondary FM conditions

AEMO would include all 4-second performance values even when FM is within the FM deadband (between -0.010 and 0.010). The condition applies only if FM remains within the deadband for the whole of the 5-minute interval (i.e., does not exceed 0.010 for regulating raise services or reduce below -0.010 for regulating lower services). If all 75 intervals of the FM are within the deadband, this indicates that the instantaneous frequency did not deviate significantly from 50 hertz (**Hz**), which means it is unlikely to require significant PFR action. On the other hand, removing these secondary FM conditions might lead to a unit being classified incorrectly as a causer at small FM values.

Misalignment between the FM and frequency deviations

AEMO notes that there is potential for the FM and FDs to indicate opposite needs to raise/lower power system frequency.

To understand how often this occurs on average, AEMO conducted an analysis on historical power system frequency data. Figure 1 and Figure 2 respectively show the percentage of trading intervals for different numbers of misalignments when frequency is higher and lower than 50 Hz.

In about half the trading intervals assessed, there is not a single 4-second interval where the FM indicates a need that is opposite to the FD when it is outside the primary frequency control band (**PFCB**) (which is the deadband outside of which PFR must be provided by relevant generating plant, currently 49.985 Hz to 50.015 Hz). Overall, in 99% of trading intervals, the misalignment happens five times or less out of 75 (or around 6.7% of the time). AEMO considers that this demonstrates there is good alignment between the FM and FDs almost all of the time.

Figure 1 Occurrence of 4-second intervals when FDs >15 mHz and FM > 0

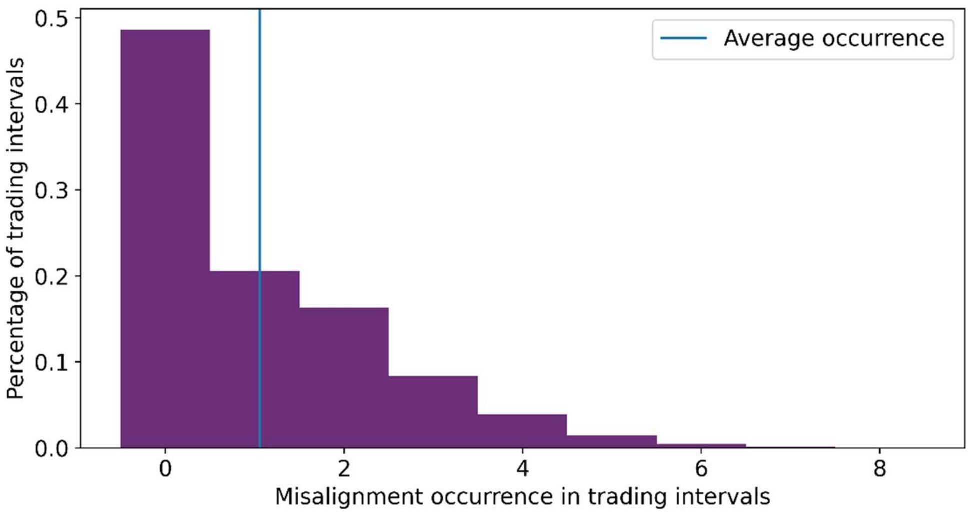
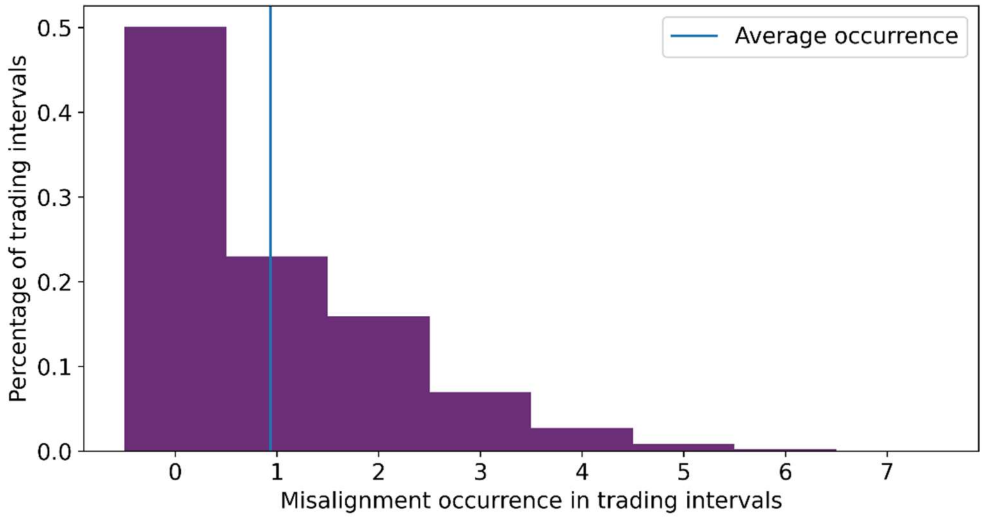


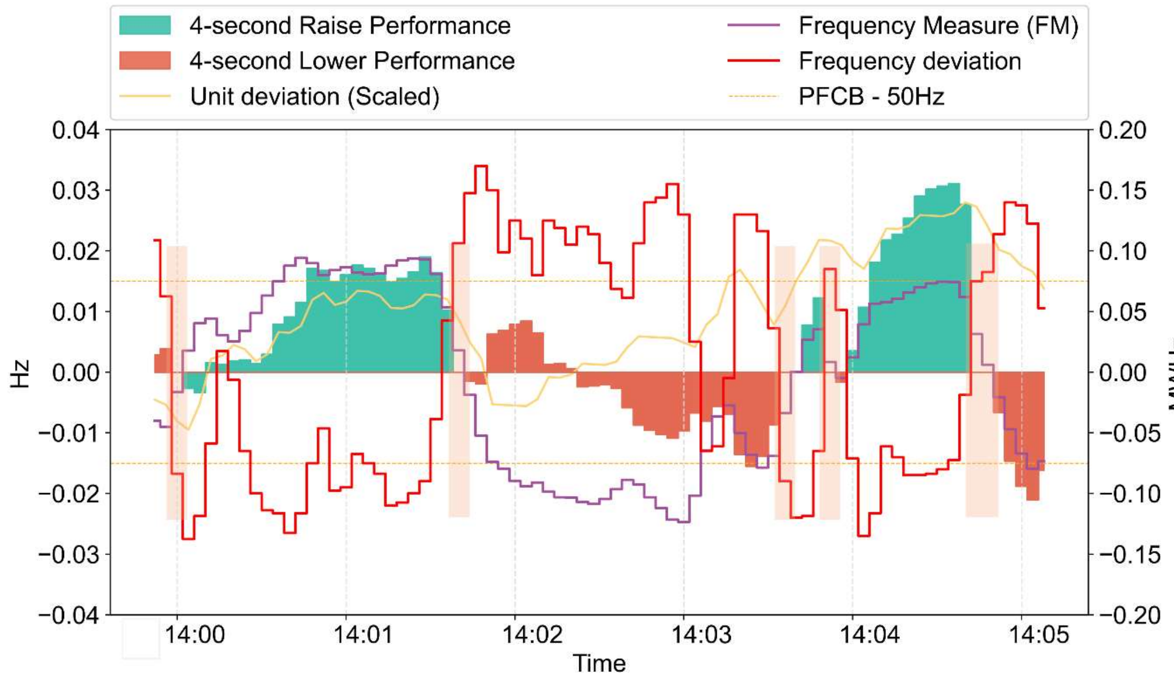
Figure 2 Occurrence of 4-sec intervals when FDs <15 mHz and FM < 0



Where misalignment does occur, AEMO sought to understand the financial impact of ignoring the 4-second intervals of misalignment between FM and FDs by comparing the FPP settlements in this scenario (which sets unit performance values to zero in those intervals) with the base case for an 80-day historical period. The results did not show any material impact on the FPP net settlements.

Nevertheless, AEMO agrees with Shell Energy's and AEC's suggestions to ignore the 4-second intervals (i.e., set the 4-second performance value to zero) when there is a misalignment between the FM and FDs only where the raw frequency is outside the PFCB in the opposite direction from the FM. This should ensure that generating units correctly providing PFR are not penalised. An example of such cases is shown in Figure 3, where the 4-second performance values of a unit are set to zero at 4-second intervals where there is a misalignment between the FM and FDs (there intervals are highlighted in the figure).

Figure 3 Impact of ignoring 4-second intervals where the FM and FDs are misaligned



4.2.3. AEMO's conclusion

EMA and need for review

AEMO intends to monitor implementation of the EMA configurable parameter and will undertake a review of the parameter if any material unintended consequences are identified. However, the FCFP will not include a regular review requirement for the EMA.

Secondary FM conditions

There is no need for further conditions.

Misalignment between the FM and FDs

AEMO will exclude the 4-second intervals where there is a misalignment between FM and FDs, and the frequency is outside the PFCB in the opposite direction from the FM.

4.3. Default contribution factors

4.3.1. Issue summary and submissions

Default contribution factors (**DCFs**) are used in two circumstances:

1. When calculating the cost recovery for unused Regulation FCAS.
2. Where it is impractical for AEMO to calculate a CF for an eligible unit for the cost recovery of used Regulation FCAS or determining the FPP.

NER 3.16AA(f)(8) requires AEMO to use historical data when calculating a DCF, unless it is impractical, in AEMO's reasonable opinion. AEMO's draft determination was to use a 28-day historical performance period for DCF purposes.

Moreover, AEMO concluded that if any of the conditions in Section 4.2 of the draft FCFP apply, the requirement for corrective response (**RCR**) and Usage will be zero, so no FPPs will be due or paid and all Regulation FCAS costs will be recovered based on DCFs applied under NER 3.15.6AA(d).

Two submissions were received on these issues.

CS Energy

Calculation

To incentivise participants to understand and address poor default contribution outcomes, CS Energy does not support AEMO's proposal to continue using the 28 averaging period for the calculation of the default contribution period. CS Energy would encourage AEMO to investigate viable alternatives to the 28 period to provide timely feedback to PFR providers.

Application

CS Energy has concerns with AEMO's proposal to suspend FPPs for PFR providers when a separation event results in an electrical island that is not aligned with a regional boundary. Extended operation of an electrical island, such as the Victoria and South Australia Separation Event on 31 January 2020[3], would be prejudicial to stranded PFR providers.

…

CS Energy has concerns with the AEMO proposal to apply DFCs in the event an electrical island does not align with a region boundary. The response to the Frequency of the power system above may remove the need for this proposal.

Shell Energy

Formulation

Shell Energy does not support the continued use of the 28 day averaging period for the calculation of the DFC. Once additional time is added for AEMO's CF calculation process and the requirement to publish 5 business days in advance, the time period on which participants payments is based could be 48 to 21 days misaligned with FCAS prices which are calculated in real time. This framework provides little incentive for participants to focus on causes of poor DCFs.

We consider that a 7-day averaging period would more accurately reflect a generating unit or scheduled loads causation of the need for Regulation FCAS. In addition, our preference is that this be a rolling 7 day averaging period with daily publication via the Electricity Markets Management System (**EMMS**) table as opposed to a static 7 or the proposed 28 day period published weekly or every 28 days via a PDF file. This would provide improved incentives for generating units and scheduled loads to improve on poor DCF outcomes as it more closely aligns performance with payments. Publication of the CF via the EMMS allows for easy automation of the CF into participant's bidding and dispatch systems. In the event that dispatch or SCADA data was of poor quality, or insufficient to allow the calculation of a reasonably accurate DCF for an eligible unit, the participant would be allocated the previous days, or last known good, DCF.

We also recommend that AEMO should consult on the ongoing need for the 5 business day notification of the DCF. The temporal accuracy of the DCF would be further improved if this requirement was reduced to align with publication of the initial pre-dispatch for the relevant trading day via the EMMS.

Shell Energy supports AEMO's proposal to cap historical trading intervals with positive performance at zero for each trading interval that makes up the historical performance period for the calculation of the DCF to apply to the unused or used Regulation FCAS portions. This notes that where positive contribution occurs for the active service this will be rewarded separately to the Regulation FCAS payments by the FPP. Given this separate payment, poor performance should not be netted out by good performance.

We also support AEMO's proposal to allow netting of poor and good performance, but still capped at zero, for those limited trading intervals where actual performance cannot be calculated and instead a calculated historical performance value is used as a substitute for actual performance. This would result in an outcome where an eligible unit that "on average" was a good performing unit would not be liable for FPP.

Application

Shell Energy does not support application (use) of the DCF when an electrical islanding event is not aligned with a regional boundary. We consider that our proposal as set out above for additional frequency measurement points and

[3] https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/final-report-victoria-and-south-australia-separation-event.pdf?la=en

> temporary reassignment of an eligible unit, if required, provides improved incentives for the ongoing provision of PFR under what could be challenging power system conditions.
>
> We note and support AEMO's proposal to substitute with the DCF were local SCADA data failure impact one or a small limited number of eligible units. AEMO has also raised the issue of not continuing FPP in the event of a regional or global SCADA data failure. In the event there was a generalised and widespread failure of SCADA data that impacted multiple eligible units across all regions, then Shell Energy agrees that the FPP calculation should be suspended and DCFs would apply. AEMO's operating procedure SO_OP_3706 Market Suspension and Systems Failure in section 8.2 may provide additional guidance in this area with regards to criteria to be met to declare a global SCADA data failure. When such a rare event occurs participants should be advised by market notice that FPP has been suspended.
>
> However, for a regional SCADA data failure, we question if FPP should be suspended as proposed by AEMO as doing so would remove the incentive for eligible units in non-affected regions to continue to supply the required service. RCR could still be calculated for non-affected units and in this case the DCF would be applied to the affected units. A eligible units that "on average" was a good performing unit would not be liable for FPP, however, poor performing units would continue to incur a FPP liability. This maintains the incentives for the continued provision of the required service and for good performance overall.

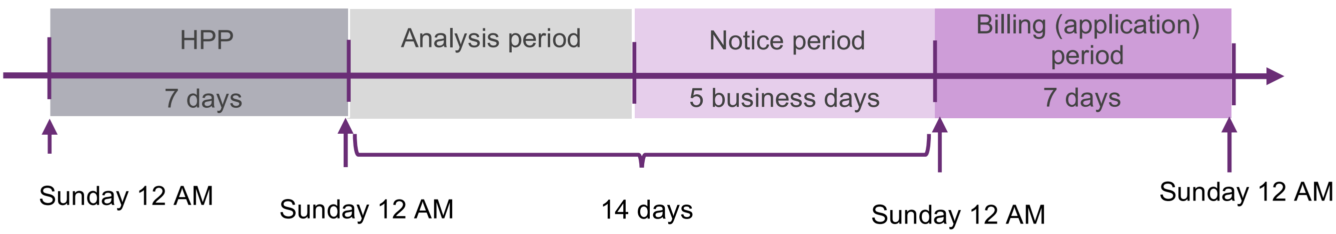
4.3.2. AEMO's assessment

There are several issues arising from the submissions that AEMO will address separately.

Calculation

Noting the support for a shorter historical performance period (**HPP**) to produce DCFs that are likely to be a better reflection of recent performance, AEMO needs to balance this with the need to maintain reliability of the DCF calculation. A 7-day HPP would increase the likelihood of insufficient historical data, and so must therefore be supported by additional measures to calculated DCFs when there is insufficient historical data in the 7-day timeframe.

For clarification, the following timeline is proposed:



where

- HPP: 7-day historical performance period.
- Analysis period: AEMO may assess and exclude bad quality data from the historical data prior to publication of data used to determine DCFs.
- Notice period: NER 3.15.6AA(i) requires publication of data used to determine DCFs 5 business days before the billing period in which the DCFs will apply.
- Billing (application) period: period in which the DCFs are applied.

Notification of DCF

The requirement to publish data used to determine the DCFs at least five days before the relevant billing period is a NER requirement, which AEMO has no authority to vary through the FCFP.

Application

As discussed in Section 4.1, the application of DCFs where there is intra-regional separation appears to be the most efficient solution. AEMO has not identified any reliable and economically efficient alternative methodologies to address the distinct components of the procedure, including frequency measurement, the residual calculation, and the relevance of eligible units to the Regulation FCAS requirements in instances where separation does not align with regional borders.

4.3.3. AEMO's conclusion

Calculation

The length of the historical performance period will be 7 days, reduced from the 28 day period proposed in the draft report, with additional measures outlined in section 6.4.4 of the FCFP to apply where insufficient historical data is available.

Application

AEMO will continue to use DCFs where there is intra-regional separation.

4.4. Requirement for corrective response

4.4.1. Issue summary and submissions

The RCR is a measure of the total volume in MW that contributed to reducing the deviation in frequency of the power system used to scale the total amount of FPPs. In the draft report, AEMO concluded that the RCR for raise and lower requirements is to be determined by the 'peak' of helpful deviations in each direction and that RCR would be determined for global requirements based on 4-second intervals where the FM for Tasmania and the Mainland was aligned.

Three submissions were received on this issue.

AEC

> **Capping**
>
> The AEC is not opposed to the capping of extreme RCR values, and thanks AEMO for estimating the materiality of its proposed caps, but feels the procedure requires greater clarity in explaining the objective of a cap. In the AEC's mind, a cap for a new payment mechanism is appropriate if its objective is limited to excluding only extreme outcomes that have been caused by:
>
> - A systems failure creating anomalously large values; or
> - Circumstances that are clearly well beyond the system's intention to reward investment in frequency correction.
>
> These are very rare circumstances. In contrast, the AEC is not comfortable with AEMO determining a cap in order to limit market risk more generally which would be outside AEMO's role.
>
> The draft proposal's cap activates between 0.1% to 0.4% of the time. Noting the AEC is not aware of the detailed circumstances of those instants of activation, this result seems less rare than the AEC would have expected from a cap tuned only to its preferred limited objectives.
>
> The AEC recommends that:
>
> - the procedure explicitly describes the purpose of RCR capping along the limited lines the AEC has suggested;
> - the proposed caps are reconsidered with respect to whether they meet those objectives and only those objectives;
> - the caps are regularly reviewed post implementation for their appropriateness with respect to those limited objectives.

CS Energy

> CS Energy has reservations on AEMO capping the RCR and how this impact on the final FPP. An alternative approach would be to have a deactivated RCR cap and in the event specified triggers were exceeded, the RCR cap would be invoked and the NEM advised of the outcome.

Shell Energy

> Shell Energy does not support capping of the RCR value. However, we acknowledge AEMO's reasoning as to why an RCR cap may be beneficial for the initial years of FPP operation to allow the market to develop confidence in this new framework. What is not clear in the draft procedure is how the FPP would be calculated and distributed to participants who have provided PFR in good faith when the actual RCR value exceeds the RCR cap value. Would each service provided receive a simple prorate share of the payment. The framework regarding this should be detailed in the Procedure.
>
> AEMO has proposed that any RCR cap should not be active for greater than 0.4% of trading intervals in any year. This equates to 420 trading intervals per year. Shell Energy considers that a threshold of 0.1% or 104 trading intervals would be a more acceptable threshold.
>
> We note that AEMO proposes to use a multiplication constant applied to the Regulation FCAS left-hand side term in the applicable Regulation FCAS constraint equation review to give effect to this RCR cap and to review the RCR multiplication constant annually. Shell Energy is comfortable with this proposed methodology, however, in addition, this annual review should include a review of the continuing need for the RCR cap with a view to removing the RCR cap when appropriate or by a defined period not exceeding three years. This would prevent a degree of free riding by poorly performing entities on PFR providers.
>
> With regards to the calculation of the RCR value, this should only represent the sum of the deviation values on individual eligible units' values for which good SCADA data is available.

4.4.2. AEMO's assessment

After considering the reservations expressed in submissions, AEMO has reviewed the requirement to incorporate a standing cap on the value of RCR. Noting that the RCR can be recalculated when bad quality data causes an incorrectly high RCR, AEMO has concluded that it is not in fact necessary to cap the RCR value.

4.4.3. AEMO's conclusion

RCR will not be capped. Section 7.5.3 will be deleted from the FCFP.

4.5. Usage

4.5.1. Issue summary and submissions

The concept of Usage represents how much of the total enabled amount of a Regulation FCAS requirement was used during a trading interval. In the draft FCFP, it is a factor that determines the percentage of Regulation FCAS costs recovered on the basis of negative CFs (based on measured performance within a trading interval) and the percentage recovered on the basis of DCFs (based on historical performance).

AEMO's draft report endorsed the original proposal to calculate Usage as the maximum (at any point during a trading interval) of the sum of positive deviations for all eligible units with appropriate metering that are enabled to provide the relevant service (deviations of each unit capped at the level that the unit was enabled).

Only one submission was received on this issue.

Shell Energy

> Shell Energy supports AEMO's proposal to use the of the sum of positive deviations for all eligible units with appropriate metering that are enabled to provide the relevant service (capped at the level each unit is enabled for regulation FCAS) that determines what percentage of Regulation FCAS costs are recovered on the basis of CFs (based on measured performance within a trading interval) and what percentage are recovered on the basis of historical DFCs.
>
> For the calculation of overall PFR for FPP, this should be calculated on the sum of positive deviations for all eligible units with appropriate metering regardless of enablement for the provision of Regulation FCAS excluding any Regulation FCAS enablement cap.

4.5.2. AEMO's assessment

AEMO acknowledges Shell Energy's support for the way Usage is addressed.

AEMO does not calculate the "overall PFR". However, if "overall PFR" refers to the RCR, AEMO acknowledges that unit level caps will not be considered in the RCR calculation.

4.5.3. AEMO's conclusion

There will be no change to the FCFP to address Usage.

4.6. Reference trajectories

4.6.1. Issue summary and submissions

NER 3.15.6AA(g)(7) requires AEMO to consider the following when determining a reference trajectory for each eligible unit with appropriate metering in each trading interval:

- if the eligible unit is scheduled, the dispatch target at the end of the previous trading interval and at the end of the relevant trading interval;
- if the eligible unit is semi-scheduled, the dispatch level at the end of the previous trading interval and at the end of the relevant trading interval;
- if the eligible unit is non-scheduled, where practical, any information provided by a Registered Participant for the unit that relates to its expected trajectory over the trading interval.

The reference trajectory methodology may also be informed by any other factors AEMO considers relevant.

AEMO concluded in the draft report that its original proposal of reference trajectories based on the requirements specified in NER 3.15.6AA(g)(7) was appropriate and it was not necessary to account for additional factors.

In the draft report, AEMO noted concerns that delays in the receipt of dispatch instructions could cause a unit to deviate from its target trajectory, with anecdotal reports of delays up to 20 seconds after the start of a trading interval. AEMO analysed the impact of such delays, and concluded in the draft report that disregarding the first 20 seconds of performance data in each interval would make no material impact to units' FPP settlements.

Four submissions were received on this issue.

AEC

> A frequently discussed matter in the design of FPP is the choice of the dispatch trajectory against which the DUID's SCADA is measured. The Draft procedure proposes to use the trajectory between the "cleared MW" quantities produced by the dispatch engine.
>
> AEMO's position is that this Draft procedure's approach [on reference trajectory] is obliged by the new rule 3.15.6AA which draws the trajectory from the "dispatch target….at the end of the previous trading interval…". However "dispatch target" is not a defined term in the Rules. AEMO is using the term in its common meaning, however it may be legally open for the procedure to interpret "dispatch target" differently if other values prove more appropriate.
>
> In particular units operating on AGC are driven to an AGC output setpoint which can be materially different to the cleared MW, and it is of concern to AEC members that DUIDs will be effectively penalised by the complying with an AGC set point. It may be possible to capture this set point as at least the launch point for the trajectory.
>
> For non-AGC units, a cleared MW to cleared MW trajectory seems appropriate, but this should take into account inherent latency in the issuing of a dispatch instruction. An approach may be to begin and end the trajectory at a delay from the start and end of the dispatch interval, recognising these latencies.

The AEC is not explicitly recommending any of these technical adjustments, but is noting that they deserve detailed analysis by AEMO to determine whether the result would represent a more reasonable and fairer implementation. The AEC recommends that is done through this consultation period and considers there is adequate time for this analysis ahead of the implementation date of June 2025.

CS Energy

The delay in AEMO issuing dispatch instructions is a known outcome. The key concern is the resultant misalignment between scheduled plant output and any proposed trajectory that will be utilised to determine PFR performance. Any known and measurable delays should be incorporated into the trajectory being utilised to determine PFR performance.

CS Energy prefers the AEMO Automatic Generation Control (AGC) setpoint 'hand shake' to be the determinant of the reference trajectory. Any further developments on the reference trajectory should be suspended until the completion of the AEMO AGC forums scheduled on 21 March 2023 to enable any feedback and learnings to be incorporated into the final design of the reference trajectory.

Delta Electricity

The weakest link in the chain towards greater overall accuracy is the performance trajectory which will impact on all the outcomes of this procedure. It is acknowledged that this aspect of the process was not reconsidered as it was implied within the Rules as produced. However, the Rules as produced do propose latitude for AEMO designers to consider in detail what a target to target trajectory really means and design whatever adjustments AEMO considers is needed to improve it whilst still conforming to be target to target. … To be a reasonable performance expectation, Units with traditional controllers should be measured against what can be expected from them in automatic conformance. A target-to-target trajectory applied each trading interval does not respect the assigned ROC of the local unit controller or acknowledge the ROC is an applied setting not presently designed to be automatically adjusted to cater for expectations that arise from the performance trajectory. Modifying unit controllers to provide reactive and varying local unit controller rates of change (ROC) to suit an unnatural trajectory should not be an objective of procedures to incentivise better PFR.

To be truly incentivising, the process and the resultant factors need to respect the realities of what Units, subject to Automatic Control driven by an AEMO targeting and 4s control system, can presently do as designed. … For such Units, the central controller and/or the procedure need to respect that the faster local controller is always approaching its local setpoint, and should not:

1. Read a reference basepoint, from which to determine the next target, that is:
   a. too volatile to be considered a stable reference or,
   b. more importantly, not representative of where the Unit will be, or will be approaching, closer to time zero of the next interval in between the time that the central controller can actually read an energy output condition to provide a basepoint and when it can then commence delivering the new target,
2. Subsequently, due to the basepoint choice and timing of the reading of it, issue targets that Units on automatic control cannot meet, and/or
3. Expect a full 5minute's worth of ramping can take place when an interval is effectively being shortened because new targeting information from the central controller is delayed in arrival to the unit eliminating some ramping time from the 5-minute period and therefore reducing the possible obtainable ramp from an automatic unit controller set with the same ROC as the unit energy bid.

Either the targeting system and its interactions with Unit controllers should be collectively modified to reduce the targeting inadequacy so that the procedure's target-to-target trajectory is a more appropriate performance measure or the procedure considered for a further review to overcome the inadequacies contained within the targeting process to improve the reliability of the performance trajectory used in the calculations. The PFR incentivisation is meant to be assigning incentives to have better PFR reactions and the inadequacies mentioned above are not, in some opinions, representative of inadequate PFR reactions. Instead, they represent inadequate coordination between the control systems of AEMO and participants. It is hoped the forums to be held during 2023 on AEMO's Automatic Generation Control (AGC) examine these points and improve understanding within AEMO and participants of the control systems of each party. This effort and any resultant changes to the systems may address the above issues that erode the accuracy of the proposed targeting trajectory as being a PFR performance reference for this procedure.

In order to explore the overall impacts on general outcomes, a single random day of dispatch data of a single Vales Point Unit was explored and charted and is attached to this letter for examination by AEMO.

Of 288 dispatch intervals of the sampled day:

- 179 intervals of this sample day (or 62%) are steady loading which as previously discussed are worth reviewing in consideration of whether actual to target trajectory lines rather than target to target trajectories offer any particular merit for such conditions but also demonstrate how the variations in Unit output will sometimes present as

performance and causation partially influenced by frequency erraticism. However, in assigning trajectories from 5minute data, results from an actual to target trajectory would probably display similar performance/causation variations to that of the target to target trajectory.
- The remaining 109 dispatch intervals are therefore periods of some form of ramping to the energy target of the unit.
- 27 ramping targets from the AEMO AGC are beyond the reach of the Unit setpoint moving automatically at the applied Unit ROC rate from the time t=0 of the trading interval (another two also assigned targets so marginally beyond reach as to be ignored in this analysis). Any delay in the timing of arrival of the dispatch also reduces the time available for a ramp to complete before the end of trading interval but this analysis of such has not been summarised here. Delays in commencement can be observed in the charts.
- The 27 impossible targets also affect the subsequent trajectory generated for the next interval meaning 54 trading intervals are affected. Collectively, this means during the energy ramping conditions of a typical sample day on a typical unit, around 50% of target to target trajectories, are not reliable PFR performance guides. As a proportion of the entire day, this represents 18.8% of the day.
- 52 of the ramping targets (48% of ramps or 18% of the day), some coincident with targets following impossible targets, also display the effects resulting from the local Unit ROC being under utilised either due to energy dispatch not requiring the full capability of the energy bid at the bid ROC or the Unit ROC being higher than the energy bid ROC achieving the assignment often in half the required time in the trading interval. True performance trajectories for such dispatch on Unit such as Vales Points could be designed from the local unit setpoint read at least twice in every dispatch interval and a reference to the applied Unit ROC.

Although all participants will be assessed against a similar designed trajectory which means some sort of consistency in itself results, the performance trajectory currently utilised in the existing system and proposed for the new system carries too much inherent randomness to be an effective “PFR performance” guide from trading interval to trading interval to offer a reliable enough PFR performance assessment to convince control engineers of various participants that better PFR will fix performance against such trajectories. Instead, participants may choose to design controllers to deliver better performance against the trajectories from the arithmetic of the performance measures. Such modifications will need to assign variable ROC capability in the local unit controller which would not represent better PFR and may actually contribute to worsening overall frequency coordination.

In addition, the highly erratic nature of the standing frequency conditions will still impact on the frequency measure as presently proposed but it is acknowledged that the smoothing factor as proposed based on 2021 data may undergo adjustment over time and also that nothing will be perfect when experiencing such erraticism. Eliminating the frequency erraticism, if at all possible, by other coordinated actions from AEMO and participants would probably improve the overall performance of PFR.

It also would be better if the performance trajectory for this procedure was designed with more consideration of local Unit controller setpoint conditions and trajectory and with better consideration of automatic dispatch. Such performance measures, if designed correctly, ought to capture only the variations from that expected from automatic dispatch controllers, as applied locally, rather than expect local unit automatic reactions, designed and implemented for many years to respond to central dispatch in the way they do, to conform to performance trajectories that present both unreachable targets and targets requiring a regularly revised ROC to achieve smooth conformance over 5-minutes instead of a shorter period as driven by the applied local ROC.

ATTACHMENT – 6 February 2023 – VALES POINT UNIT 5 DISPATCH RESPONSE

Basepoint choice

The choice of referring to a single snapshot of actual MWs from a fedback value from the Unit has two sources of inaccuracy:

1. The single snapshot is taken from a volatile value. It would be better to get an averaged value or allow for the volatility with some level of adjustment. The volatility contributes to the possibility of erroneous next target determinations.
2. The timing of the read, understood to be 20s before the end of a trading interval, is also prone to contributing to error in dispatch in two ways, due to the possible changes that occur in the 20s following, one affecting dispatch conformance and one affecting the next target:
    a. The dispatch conformance arithmetic and the reliance on an actual MW value read 20s before the end of the trading interval, often reports off targets that, from data read locally and precisely at the end of the trading interval, do not truly occur and
    b. A basepoint assignment, based on that actual MWs read 20s before the end of the trading interval, is likely to result in erroneous targeting other than just because the signal is highly variable but also because of unit response that follows that reading.

The local Unit Setpoint signal is a more reliable guide from which to set a basepoint for the AEMO AGC central controller because it is a steadier value more realistic of where the Unit is locally driven by the faster local control processes. However, it has to be acknowledged that plant conditions can, on occasion, result in causation under this procedure and so any use of the Unit setpoint continuously would not always result in a fair outcome. Some adjutsments to the local setppint can be due to FCAS controller reactions, which generally should generate performance against a trajectory assigned in advance of real-time conditions and some reactions can be automatic plant reactions to secure the Unit, which generally should generate causation. However, at the start of a dispatch interval, the basepoint has to be set from something and the evidence in this report suggests that the volatile actual MW meter value read some 20s before the end of a trading interval is not the best choice and results in many 5-minute intervals when the PFR performance outcomes measured against such a trajectory are erroneous because the target generated from the AGC from a reading of the volatile MW value is often unachievable by a unit in automatic dispatch.

The Unit setpoint, which is the produced from the received dispatch target, could be referred to by AEMO as the target of relevance to base the start of the trajectory for each interval without contradiction with the PFR incentivisation Rules. Where Units return this value to AEMO each 4s, AEMO could opt to utilise this accurate targeting information to develop the next target in the AGC more precisely in basepoint reference at time zero of each trading interval or use the data in the proposed calculations of this procedure. Similar data is understood to be available in the AEMO system as returned from large Units. When a unit is off its local setpoint, this is true cause of frequency support or causation from a local perspective. However, sometimes the setpoint will include outcomes from the Unit controller, in response to sudden contingent plant conditions, that adjust the unit setpoint to the safest level the Unit can maintain, which can be significantly off the expected and possible dispatch trajectory. Despite this possibility, in developing the target for the next trading interval, the AGC would in general benefit from adopting the local unit setpoint as the basepoint for dispatch decisions rather than the Actual MWs value which is more volatile.

The AGC targeting, by assigning a basepoint from a volatile reading of Actual MWs read in advance of reactions which continue after it has been read, adds randomness to the targeting result because the next target is based upon a single snapshot of energy at a single point in time. This continual process introduces a great source of randomness and inaccuracy in the overall dispatch and frequency control objective. Setting the basepoint for dispatch targeting from the Unit setpoint, a more stable signal and the local target the Unit is controlling to, will provide a steadying impact on overall dispatch and frequency control objectives.

The existing FCAS CF system with its 28 day assessment and determination from averaged points of view of raise and lower FCAS regulation status Not Enabled and Enabled and eliminating only the positive outcomes from the Raise and Lower Enabled intervals seems to get a more sensible causation factor because, as AEMO expects will occur with the new system, the errors in trajectory from trading interval to trading interval cancel out. However, if the DCFs of the new system are specifically eliminating all positive factors both enabled and not enabled, it is expected the DCFs in the procedure will worsen relative to the present ones, partly due to the trajectory choice which, according to the sample charts from a typical day of dispatch at Vales Point, regularly results in individually poor trading interval outcomes. From a control engineer perspective looking at the relevant case examples below of poor or good performance, the data and charts presented in this report suggest to Delta Electricity that incentives to improve Unit PFR reactions will not result from performance/causation based on flawed trajectory assignments. It continues to be our recommendation that AEMO, now or in the future, reconsiders the trajectory design of this procedure and/or raises the priority on actions to better coordinate NEMDE/AGC arithmetic and controllers with Unit controllers to improve the accuracy of outcomes from the procedure and the resultant settlements.

For Units that are returning the local setpoint to AEMOs AGC every 4s, a future procedure could design a more accurate target to target trajectory from referencing the local setpoint signal more often than once each 5 minutes. Catering for possible automatic unit reactions to local conditions that seek to prevent unit interruption would be required suggesting some caution is required in simply relying upon a continuous monitoring of the 4s setpoint but in many intervals where no plant conditions impact, the setpoint provides a continuous information source from which a more concise performance trajectory could be designed one that would not need to compromise on performance objectives that linearising all ramping trajectories across a full five minutes leads to. From the evidence presented below many actual applied trajectories during ramping on Units like at Vales Point do not follow such simplified expectations.

Unit AGC Delay in Target signal arrival

If the AEMO AGC dispatch signal doesn't commence arrival to a Unit until 30-60s into the trading interval, the delay in commencement represents time already lost from the achievable 5 minute ramp that ought not result in causation for a Unit under this procedure.

The Unit has to change the energy output by the amount dispatched which is usually caclulated on the full five minute interval. Unless the local controller ramp rate is greater than the energy bid ramp rate (which is possible but not mandatory) the Unit may not be able to achieve a late arriving target. Therefore, the targeting system, or this procedure, ought to make an allowance for the delay in target commencement to the Unit and only expect the ramp of a Unit to achieve the target represented by Ramp Rate * (5 – AGC target delay time). e.g. if the Unit ramp rate is 3MW/min, then in 4.5minutes due to deficiency in the AEMO AGC delivery, a dispatched Unit can only achieve 13.5MW in the 5 minute interval and not 15MW as would be theoretically possible if the AGC delivery was never delayed in arrival. However, it is also possible that the AEMO system (not well understood by the author) makes some adjustments for this effect.

6 February 2023 – Vales Point Unit 5 Dispatch charts and result

In the suite of charts of dispatch below, the target to target trajectory proposed yields impossible targets for 9.4% of all trading intervals (27 separate 5-minute intervals; two further dispatch intervals also generated impossible targets so small as to be ignored in this assessment). When an impossible target is dispatched, it also affects the precision of the trajectory in the following interval because, although the next target is achievable, a unit following the possible trajectory as determined by the local unit setpoint respectful of the local ROC, is on a different trajectory line. Therefore, the original impossible target affects 18.8% of all dispatch intervals and as the condition is only produced when the Unit is ramping, potentially affects 50% of all ramping intervals.

Intervals where energy ramps are required at less than the maximum capable from the applied local controller ramp rate, also take place on 52 occasions, some coincident with those following impossible targets, also impacting on the accuracy of the trajectory because the proposed linear 5minute to 5minute target to target trajectory does not properly cater for Units ramping precisely at the locally applied ramp rate. The actual Unit trajectory for Vales Point Units observing automatic dispatch will observe the local Unit ROC and, in such intervals, the Unit will reach its dispatch target minutes before the end of the trading interval. Is this sort of dispatch something AEMO is seeking to be corrected by those being incentivised by this procedure? If not, the trajectory for the procedure, or a future revision to it, should seek to respect local Unit ROCs and, where necessary, expect the target to be reached at some time before the end of the trading interval.

As a result of the collected observations of a complete day of dispatch of a single Vales Point unit, it is considered that the inaccuracy of the AGC determination of the next target and the fact that units always ramp at their ramp rate, collectively means the target to target trajectory is inaccurate for at least 18.8% of the time, and for potentially more than 50% of all energy ramping intervals in the typical day example through no real inadequate PFR from a typical Unit and that the subsequent resulting performance/causation arising from the proposed trajectory is therefore potentially random more than 50% of the periods involving energy ramping. The fact that the measured performance/causation will sometimes benefit and sometime tax the participant does indeed mean the overall financial result from random performance will smooth the variability but the intent of the procedure and the Rules is meant to be incentivising participants for better PFR control. It is difficult for participants to be incentivised by a process that shows performance or causation that a participant cannot influence except by building a very unusual controller that won't necessarily correct output for frequency conditions and more than 19% of the time appears to be measuring targeting trajectory limitations as performance/causation instead of PFR or the lack thereof.

To aid AEMO in observations of the following charts[4] several trajectory lines are drawn and/or contained in the data as plotted:

- Target to Target (green dashed line)
- Actual to Target (black dashed line)
- Unit Setpoint to a possible linearly determined target based on the energy target assigned or that which is achievable on the maximum energy ramp contained in the energy bid (navy blue dashed line)
- Continuously Tracked Local Unit setpoint (Cyan) – This setpoint is produced with adherence to the AEMO dispatch but observes the capability assigned from the setpoint and the local ROC as determined from when the AEMO dispatch starts to change early in any dispatch interval where ramping is required. This data is returned to AEMOs AGC very 4s for use in central control and could be used by this procedure to design a more accurate trajectory.
- A value of 50 was added to a calculated FMt that uses the proposed frequency measure with the proposed initial smoothing factor to compare against the plot of local unit frequency as recorded on the Unit high speed recorder.

Shell Energy

We note the analysis undertaken by AEMO on the impact of SCADA data communication delays in the dispatch process. However, we consider that the issue of AEMO delays in issuing a dispatch instruction has not been adequately address. Currently the deviations from the defined reference trajectory calculation is based on an assumption that the issuing of a dispatch instruction by AEMO perfectly aligns with the start of the trading interval. This is not correct. AEMO can issue a dispatch instruction at any time during a trading interval and historically the dispatch instruction has been issued by AEMO anywhere between 20 to 60 seconds after the start of the trading interval.

In addition to this delay this causes in a generating unit or scheduled load commencing an alteration to its dispatch output to align with the latest dispatch instruction, a generating unit or scheduled load will continue to move towards its latest dispatch instruction until the time at which a new dispatch instruction is issued. This includes continuation of this action into the next trading interval. This outcome occurs for both EMMS and AGC based dispatch.

We recommend that this observable delay in issuing of the dispatch instruction by AEMO should be included in defining the baseline trajectory to account for positive and negative deviations across the entire dispatch period which may include time periods across trading interval boundary times as required. This could be undertaken via offsetting the time period allocated to the reference trajectory by the calculated historical average delay in the issue of the

[4] AEMO note: No charts attached.

dispatch instruction by AEMO. We also consider that routine monitoring of this time delay in the issuing of the dispatch instruction is warranted with annual review and adjustment of the time offset value if required.

Shell Energy supports the calculation of the reference trajectory as a linear straight line between the two sequential active energy output dispatch instructions issued by AEMO. As indicated above, this trajectory should be calculated based on the time at which the dispatch instruction is issued and not simply based on the trading interval boundary time.

In addition, in our view AEMO also needs to take account of how the dispatch instruction is issued to a scheduled generating unit or scheduled load. In general, a scheduled generating unit or scheduled load receives its dispatch instruction via AEMO's AGC system, as opposed to directly via the EMMS. AGC is the common mechanism for providing the signalling for both Automatic Balancing Control (**ABC**) and Load Following Services (Regulation FCAS). Under AGC control, the facility can either be in ABC or Load Following Mode. The important distinction between ABC and when a unit is enabled for regulation FCAS is that while AGC is actively controlling the facility when providing regulation FCAS, ABC is only providing a representation of a dispatch instruction and an acknowledgement mechanism.

In either ABC or regulation FCAS mode, AEMO's AGC system issues a scheduled generating unit or scheduled load an AGC output setpoint which may vary from the EMMS dispatch instruction, and which may also vary during any dispatch interval. Unit setpoints are issued every 4 seconds by the AGC system. The revised unit setpoint will in each case take into account the initial active energy output and the participant provided rate of change of unit output in determining the latest output setpoint update. We consider that the manner in which the dispatch instruction is issued must also be considered in setting the reference trajectory. For units receiving its dispatch instruction via AEMO's AGC system, use of a simple target-to-target reference trajectory may result in the incorrect calculation of regulation FCAS and FPP liabilities and FPP payments for a generating unit or scheduled load operating under AEMO's AGC control.

AEMO have previously acknowledged the potential for use of a simple target-to-target reference trajectory to result in incorrect calculation of regulation FCAS contribution (causer pays) factors[5].

AEMO now considers that a target-to-target reference trajectory may not be the most appropriate basis of determining deviations with respect to the changing generation mix.

AEMO also acknowledges that alternative reference trajectories (including an initial-to-target trajectory) may provide a stronger incentive for frequency control, and therefore further work should be undertaken to understand the relative merits.

AEMO therefore intends to undertake further work to investigate the merits of alternative reference trajectories.

However, further work in this area was deferred by AEMO focussing on achieving mandatory narrow band primary frequency response and its implementation. Shell Energy considers that this further work should be progressed as part of this consultation process.

4.6.2. AEMO's assessment

Several issues arise out of these submissions that AEMO will address separately. In considering these issues, it is important to recognise that the FPP is not designed to reward all PFR provided to the system. Rather, its purpose is to incentivise frequency responses that are helpful towards maintaining power system frequency as close to nominal as is possible.

Use of dispatch targets

NER 3.15.6AA(g)(7)(i) requires the methodology used to determine a reference trajectory to be informed by the dispatch target for a scheduled generating unit, scheduled load, scheduled bidirectional unit and ancillary service unit at the end of the previous trading interval and at the end of the relevant trading interval. While other factors may be included in the methodology, it is clear that the dispatch target must be incorporated.

Although the term "dispatch target" is not defined in the NER, "dispatch" is, as is "dispatch level" (the equivalent term used in NER 3.15.6AA(g)(7)(ii) for semi-scheduled units). Chapter 10 defines "dispatch" as:

[5] AEMO Regulation FCAS Contribution (Causer Pays) Factor Procedure Consultation Final Report – November 2018 – Page 18.

> The act of initiating or enabling all or part of the response specified in a *dispatch bid*, *dispatch offer* or *market ancillary service offer* in accordance with rule 3.8, or a *direction* or operation of capacity the subject of a *reserve contract* or an instruction under an *ancillary services agreement* or to *enable* an *inertia network service* or *system strength service* as appropriate.

"Dispatch level" is defined as (emphasis added):

> The amount of electricity to be supplied by a *semi-scheduled generating unit* for a *trading interval*, **specified in a *dispatch instruction*** as the target *active power* at the end of the *trading interval*.

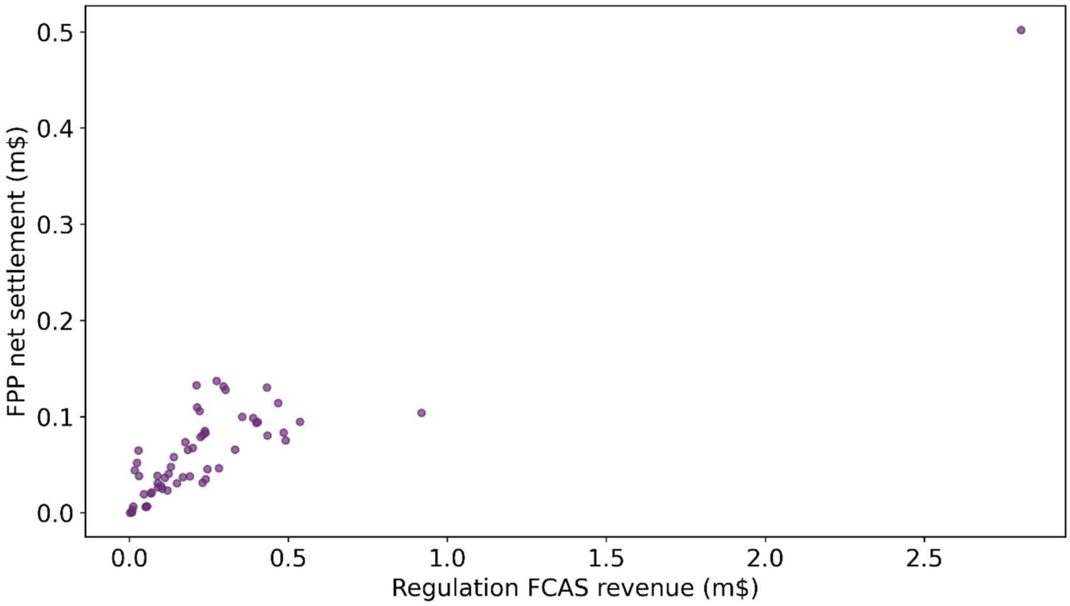
When "dispatch" is combined with "target", AEMO considers the term can only refer to the instruction given by AEMO to a participant after completing the process detailed in NER 3.8.1(b). In some instances, that instruction is contained in an AGC signal, in others it is transmitted by EMMS. As the AEC submission acknowledges, this is also the common understanding of a "dispatch target" for scheduled resources in the NEM. AEMO considers that there is no reasonable interpretation of the Rule that allows AEMO to apply a different meaning to that term.

When eligible units are enabled to provide Regulation FCAS and required to follow AGC setpoints, it is true they may be assigned negative performance based on their real-time impact on power system frequency. Following the AGC signal could result in a 5-minute negative performance when the frequency indicator (FI) and FM do not align in most of that trading interval, which results in the unit's deviations not helping real-time frequency.

However, AEMO's analysis over an 80-day period shows that, due to the positive correlation between FI and FM, when regulation-enabled units follow AGC setpoints, they receive a positive net settlement in FPP overall. This is because, in 73% of 4-second intervals when RCR is non-zero (i.e., FM conditions do not hold), the signs of FM and FI match. This suggests that even though some regulation-enabled units might incur penalties in specific trading intervals, the overall correlation between FI and FM results in a net FPP incentive for them. This is consistent with AEMO's analysis discussed in the draft report, which showed the notably positive net settlements for regulation-enabled units compared to other units and the residual.

Supporting this, a new unit-level analysis depicted in Figure 4 shows a strong positive correlation between FPP net settlement and Regulation FCAS revenue of regulation-enabled units in the mainland during the intervals they were enabled to provide either global or mainland Regulation FCAS. The new findings reinforce the conclusion from previous analysis that regulation-enabled units tend to receive positive FPP net settlements.

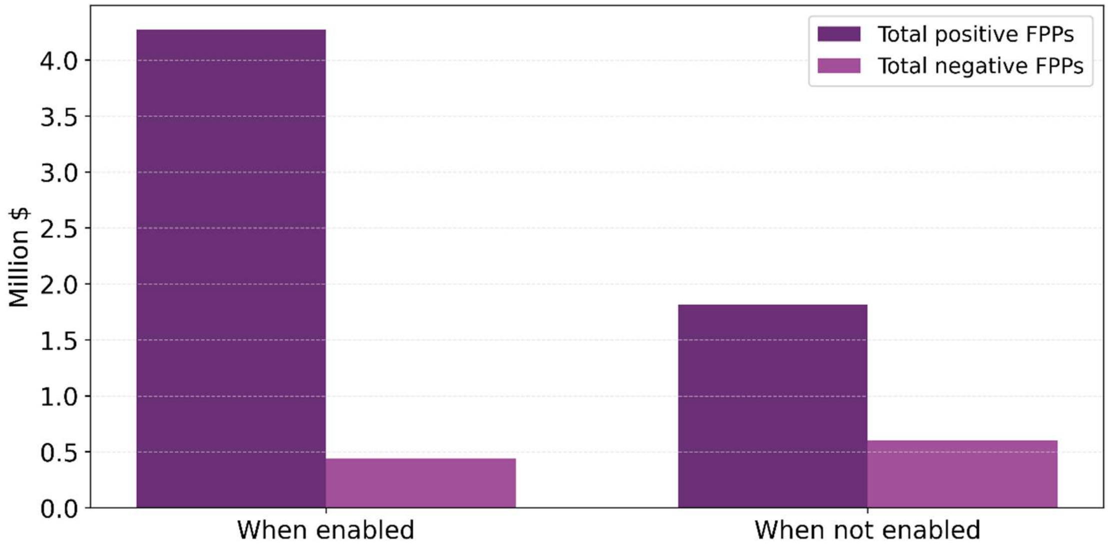
Figure 4 Unit-level analysis of the FPP net settlement of regulation-enabled units



Nevertheless, to determine the materiality of the misalignment between the FM and the AGC signal (FI), AEMO has undertaken further analysis, comparing the total FPP incentives paid to regulation-enabled units with the total FPP penalties paid by them during the trading intervals that they were enabled (thus, following the AGC setpoints). In this analysis, FPPs are calculated for global and mainland Regulation FCAS Requirements. Over the 80-day study period, the enabled units received a total of $4.3 million in FPP and contributed $0.45 million toward the cost associated with FPP. In other words, only around 10% of their good performance was offset by their negative performance when they were enabled, and they received $3.85 million in net settlements over the 80-day period when they were enabled.

Figure 5 shows these findings in more detail for the trading intervals that the units were enabled compared to the intervals that they were not. This confirms that the correlation between the FI and FM leads to significant positive FPPs paid to the regulation-enabled units following the AGC signal when they are enabled.

Figure 5 System-level analysis of FPPs paid to and by the regulation-enabled units



In light of these observations, AEMO considers that using different types of trajectories for different types of Regulation FCAS providers (AGC vs non-AGC, Regulation FCAS enabled vs not enabled, different technologies, etc) will create complexities and cost without yielding commensurate benefits. Additionally, AEMO notes that Regulation FCAS providers may factor in the possibility of a negative FPP, in addition to other factors, when submitting their Regulation FCAS bids.

Delays in receiving dispatch instructions

As noted in the draft report, AEMO's analysis showed that there is no significant change in the CFs and FPP settlements when ignoring the first 20 seconds due to potential delays in the receipt of dispatch instructions. Furthermore, assessing a linear reference trajectory following a delay from the start of a trading interval (i.e., offsetting the period allocated to the reference trajectory in the trading interval) is not a suitable or practical solution because:

- Any latency is not similar for all eligible units.
- Latency is not constant over time and using an average would not result in an accurate calculation of deviations (even assuming all units experience the same delay).
- Delay cannot be measured accurately and consistently.
- The reference trajectory in the first few seconds would be chosen arbitrarily.

The latency issue might affect any scheduled or semi-scheduled unit. Thus, there is no reason for differentiating between these two types of units. Moreover, keeping the reference trajectory methodology simple and straightforward has a material value for the units that intend to analyse their performance.

Overall, the impact of latency on FPP net settlements would not be significant because:

- The primary impact is only in the first few seconds of a trading interval, i.e., less than 10%.
- It affects all units, and AEMO's analysis indicates the impact on CFs would be minimal.
- Deviations from the reference trajectory are not always "unhelpful", so some parts of negative performance would be washed out.

Any issues related to communication delays to calculate dispatch targets needs to be solved at the source of the problem. Attempting to build allowances into new frameworks can work against resolving the problem, and entrench processes that become difficult to unwind later.

Unit inability to follow the reference trajectory

AEMO's AGC (which is similar to all known AGC systems with similar market design) uses linear target-to-target trajectory. If a linear initial-to-target trajectory is used instead, the first 4-second sample will have no deviation, but there still can be an FD that is not being addressed.

In AEMO's view, a linear target-to-target trajectory for all scheduled and semi-scheduled units provides the best, fairest reference for determining their positive and negative contributions to keeping power system frequency close to nominal. A linear target-to-target trajectory cannot take into account the limitations of each unit. NEMDE solves the energy balance equation for each trading interval, so all units following a linear target-to-target trajectory provides a constant theoretical energy balance. Any unit deviating from its trajectory means it contributes to the energy imbalance. This deviation can, of course, be caused by reasons outside the control of the unit operator. A linear target-to-target trajectory creates a level playing field, which considers all units' positive and negative contributions to power system frequency in the same manner. Given the FPP design, customising the trajectory for some units will lead to unfair CFs for the rest. Additionally, a linear trajectory derives from AEMO's Dispatch procedure[6].

4.6.3. AEMO's conclusion

There will be no change to the determination of a reference trajectory in the FCFP.

4.7. Aggregated dispatch conformance (ADC)

4.7.1. Issue summary and submissions

In the draft report, AEMO concluded that where two or more eligible units in an integrated resource system register to participate in ADC under NER 4.9, they will be assessed under the FCFP as a single eligible unit, regardless of the status of their conformance mode in dispatch for a specific trading interval.

Two submissions were received on this issue.

Shell Energy

> Shell Energy supports AEMO's proposal to treat individual generating units and scheduled loads which connect through a single connection point as a permanent aggregated unit for the purpose of calculation of regulation FCAS and FPP liabilities and FPP payments. Where individual generating units and scheduled loads connect through multiple connection points these should not be treated as an aggregated unit.

Snowy Hydro

> As part of the proposed changes, Snowy Hydro is concerned by ADC. Although ADC is being implemented as part of the Integrated Energy Storage Systems (IESS) reform there will still be technologies that are not serviced by one connection point. Where individual generating units and scheduled loads connect through multiple connection points these should not be treated as an aggregated unit as they will not all fall under the IESS reform. This should be clarified by AEMO and it should demonstrated how it would work with all generators that are not serviced by one connection point.

[6] https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation/power-system-operating-procedures.

4.7.2. AEMO's assessment

Eligible units with appropriate metering that are aggregated must be in the same region and owned by the same financially responsible Market Participant of the same participant ID.

AEMO will treat eligible units that are aggregated under NER 3.8.3 as a single *eligible unit* when determining CFs.

The National Electricity Amendment (Implementing Integrated Energy Storage Systems) Rule 2021[7] will permit eligible units to participate in ADC, and if this occurs, they will also be assessed under the FCFP as a single eligible unit.

For clarification, eligible units that connect through multiple connection points will be treated as separate units unless either of the above two conditions are met, or multiple DUIDs represent one unit in a physical sense (e.g. battery storage systems).

4.7.3. AEMO's conclusion

Clarification on the treatment of unit aggregation will be included in the FCFP.

4.8. AEMO inability to calculate and publish contribution factors in a reasonable timeframe

4.8.1. Issue summary and submissions

In the draft report, AEMO considered two options to address the problem of being unable to calculate and publish CFs within the time required by NER 3.15.6AA(k)(1) but, ultimately, concluded that it was preferable for AEMO not to calculate CFs and to recover Regulation FCAS costs by using DCFs.

Three submissions were received on this issue.

AEC

> At section 4.13 AEMO has discussed what action to take when a technology system issue has caused a delay in the CFs. Whilst the AEC agrees timely publication of CFs is a critical aspect, it does not feel that effectively pausing the process through the use of DCFs is an appropriate remedy. Instead, whilst an interruption is unfortunate and should be rectified as soon as possible, it would be better for the calculation and settlement process to continue.

CS Energy

> AEMO are encouraged to consider alternative proposals in the event AEMO is unable to calculate and publish the CFs within the specified period. The current proposal appears to be too drastic.

Shell Energy

> Shell Energy does not support AEMO's proposal to not calculate the active or used service CFs in the event AEMO is unable to calculate these within a relatively short timeframe. Instead, we propose that AEMO adopt a process similar to the current manifestly incorrect inputs and manual over constrained dispatch frameworks.
>
> Whilst it would be highly desirable to calculate CFs associated with the previous trading interval within the time period of the current trading interval, in the event of an issue occurring that prevented the publication of the factors as above, a delay of up to 30 mins in publication of the data would not impose unmanageable risks on market participants.
>
> In the first instance, when AEMO is unable to calculate the active service CFs associated with the previous trading interval within the time period of the current trading interval, AEMO would issue a market notice to indicate this. AEMO would then have 30 minutes to determine if a CF could be calculated and publish the factor if able to do so. In the event this was not possible, AEMO would issue a further market notice to indicate the trading interval is a manual

[7] https://www.aemc.gov.au/rule-changes/implementing-integrated-energy-storage-systems.

CF interval and would have until the end of the next business day to calculate the CF and advise the market of the calculated value.

We consider this retains the correct incentives for the ongoing provision of the required PFR and also aligns with well known existing AEMO price revision or determination processes.

4.8.2. AEMO's assessment

AEMO agrees with the submissions that timely publication of CFs is a vital aspect of the FPP process, which allows participants to track their performance and take necessary action to minimise their exposure to Regulation FCAS costs.

The process by which CFs are published relies on AEMO's systems' ability to retrieve data from external sources. These systems, however, can only do so for a limited period. AEMO considers it is reasonable for its systems to keep trying to access the input data for a maximum of 30 minutes after the relevant trading interval before other measures are put in place.

At the expiry of this 30-minute period, AEMO considers it is reasonable that Regulation FCAS costs be recovered on the basis of historical performance using DCFs.

4.8.3. AEMO's conclusion

AEMO will amend section 10.2 of the FCFP to state that, if AEMO's systems cannot retrieve the necessary data to publish CFs within 30 minutes after the end of a trading interval, no FPP will be determined and Regulation FCAS costs will be allocated using DCFs.

AEMO will issue a market notice after each system failure and affected Registered Participants will be informed separately. If it is not a system wide issue, only the affected Registered Participants will be notified that DCFs are being used for that relevant period.

5. Other issues

In addition to the material issues addressed in Section 4, two additional issues were raised by the stakeholders on the regular reviews and further consultation for the procedure. These are addressed in Appendix B.

6. Drafting improvements

AEMO has made several drafting amendments in the final FCFP to improve clarity and streamline the document. Changes from the draft FCFP are shown in the marked-up version published with this final report.

7. Final determination on proposal

Having considered the matters raised in submissions to the draft report, AEMO's final determination is to make the FCFP in the form published with this final report, in accordance with NER 11.152.3, following the procedure in NER 8.9.2.

The final FCFP differs from the draft FCFP in the following material respects, for the reasons discussed in Section 4 of this final report:

- AEMO will derive the frequency measurements, when feasible, from multiple sources within a given region to determine the FM in the region.

- AEMO will exclude the 4-second intervals where there is a misalignment between FM and FDs, and the frequency is outside the PFCB.
- The length of the historical performance period used in the calculation of DCFs was reduced to 7 days from 28 days.
- AEMO has removed the cap on the RCR because AEMO can recalculate it when bad data causes an incorrectly high RCR.
- Where AEMO's systems are unable to calculate CFs at the expiry of a 30-minute period after a trading interval, AEMO considers it is reasonable that Regulation FCAS costs be recovered on the basis of historical performance using DCFs.

Effective date

The effective date of the FCFP is 8 June 2025. The FCFP will replace AEMO's Regulation FCAS Contribution Factor Procedure from that date.

Appendix A. Glossary

Term	Definition
ADC	Aggregated Dispatch Conformance
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AGC	Automatic generation control.
Bad Quality	Any telemetered data that is not 'Good Quality', as that term is the Power System Data Communication Standard.
CF	Contribution Factor: A factor calculated in accordance with section 6 of the FCFP and applied to an *eligible unit* with *appropriate metering*.
DCF	Default Contribution Factor: A CF determined in accordance with 6.3 of the FCFP and applied to an *eligible unit* with *appropriate metering* in the circumstances described in NER 3.15.6AA(g)(4).
EMA	Exponential weighted moving average
EMMS	Electricity Market Management System
FCFP	Frequency Contribution Factors Procedure
FD	Frequency deviation
FI	Frequency indicator
FM	Frequency Measure: The indication of a need to raise or lower *frequency* calculated by AEMO in accordance with section 4 of the FCFP.
HPP	Historical Performance Period: A seven-day period, starting at 12:00 AM on a Sunday and ending at 12:00 AM on the following Sunday, which concludes 14 days prior to the commencement of the billing period, inclusive of the 5 business days' notice period, as referred to in NER 3.15.6AA(i).
NEM	National Electricity Market.
NEO	National electricity objective
NER	National Electricity Rules. NER followed by a number refers to that numbered rule or clause of the NER.
RCR	Requirement for corrective response, as described in NER 3.15.6AA(g)(6)(i).
PFCB	Primary frequency control band
PFR	Primary frequency response

Appendix B. List of submissions and AEMO responses

No.	Stakeholder	Issue	AEMO response
1		Measurement of power system frequency (see Section 4.1.1)	See sections 4.1.2 and 4.1.3
2		Frequency Measure (see Section 4.2.1)	See sections 4.2.2 and 4.2.3
3		Default contribution factors (see Section 4.3.1)	See sections 4.3.2 and 4.3.3
4		Requirement for corrective response (see Section 4.4.1)	See sections 4.4.2 and 4.4.3
5		Usage (see Section 4.5.1)	See sections 4.5.2 and 4.5.3
6		Delays to dispatch instructions (see Section 4.6.1)	See sections 4.6.2 and 4.6.3
7		Reference trajectories (see Section 4.6.1)	See sections 4.6.2 and 4.6.3
8		Aggregated dispatch conformance (see Section 4.7.1)	See sections 4.7.2 and 4.7.3
9		AEMO inability to calculate and publish contribution factors within a reasonable timeframe (see Section 4.8.1)	See sections 4.8.2 and 4.8.3
10	AEC	**Regular Reviews** The AEC broadly supports the draft procedure and the consultative process that AEMO has undertaken. The AEC considers the introduction of FPPs an important reform, and whilst there are valid views that should be taken into account on elements of AEMO's design choices, all parties nevertheless strongly support the introduction of FPP on the due date of June 2025, preceded by an extended pre-production period. The AEC thanks AEMO for the provision of backcasting analysis throughout the Draft Report which has provided a much more practical grounding for the necessary design choices than had the Report discussed them purely theoretically. Backcasting analysis of financial turnover in figure 11 and in more detail as presented at the forums was also very useful in confirming that the overall design meets expectations. The FPP design requires the procedure to undertake a number of judgements regarding the smoothing of metered information and approaches to building reference trajectories. Inevitably there are mixed views, but the AEC acknowledges AEMO has provided a reasonable explanation of how these draft judgements were made. The backcasting has been particularly helpful, but the AEC suspects real FPP operation will provide a stronger evidence basis. Therefore the AEC suggests the procedure include a requirement for regular reviews of the FPP operation after implementation in order to re-assess the validity of these judgements. The AEC notes some differences of views between members and AEMO arise because of perceived deficiencies in AEMO's AGC system, which leads to the policy question of whether the	The FCFP is able to be revised through the rules consultation procedures if and when changes are required, however changes may also be required to AEMO and/or participant systems. Any need for change will become evident in the regular operation of the FCFP, and would be discussed with the industry through consultative forums such as the Electricity Wholesale Consultative Forum (EWCF). On that basis AEMO does not consider a regular review of the FCFP is warranted. AEMO understands the concerns raised in relation to the AGC system, and the interdependencies with elements of the FCFP. As previously outlined, AEMO's approach is to engage on the AGC matters separately to the FCFP consultation, and notes that the first meeting of an AGC Forum was held on 14 April 2023, and AEMO is committed to ongoing transparency and improvement of AGC as part of our role in operating the power system.

No.	Stakeholder	Issue	AEMO response
		FPPs should be adjusted to account for this. The AEC understands AEMO's response to this view is that deficiencies in AGC should be resolved within the AGC system itself. FPP should operate only upon observed plant behaviour in support of, or in opposition to, the frequency, regardless of its cause. The AEC does not disagree with the logic of AEMO's response, but notes that over an extended period of time its membership has frequently raised concern about the performance of AGC which do not appear to have been adequately addressed. Whilst the AEC agrees that AGC design and performance is outside the scope of this consultation, if AEMO is to take this response, it is incumbent upon AEMO to commit to a plan of action to address the matters raised.	
11	Shell Energy	**Further consultation** There are a number of significant issues that are yet to be determined to allow this new framework to provide acceptable outcomes to participants. Given that implementation is scheduled for mid-2025, we consider there remains sufficient time to work through these issues to deliver the best solution of the market overall. We recommend that AEMO consider issue of a directions paper as a next step with further industry technical working groups prior to formulating their final determination report.	AEMO does not consider issuing a directions paper and delaying the publication of a final determination is warranted because: • The relevant issues raised in submissions have been addressed. • AEMO is required to publish the final determination by 8 June 2023. Apart from the compliance issue it raises, delaying the finalisation of the FCFP carries additional cost and risk for AEMO and all impacted participants. • Even with a two year implementation timeframe, the delivery program is quite tight and the system build cannot commence until the requirements are finalised in the FCFP. • Should any issues be identified during the system build that impact on the FCFP, AEMO would commence a new consultation to address them, using the NER process most appropriate for the nature of the issue and proposed change.