Australian Energy Market Commission

AEMC
Australian Energy Market Commission

DETERMINATION

Draft rule determination

National Electricity Amendment (Improving contingency FCAS arrangements) Rule

Grids Energy Pty Ltd

4 June 2026

Enquiries

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About the AEMC

The AEMC reports to the energy ministers. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the energy ministers.

Acknowledgement of Country

The AEMC acknowledges and shows respect for the Traditional Custodians of the many different lands across Australia on which we live and work. The AEMC office is located on the land of the Gadigal people of the Eora nation. We pay respect to all Elders past and present, and to the enduring connection of Aboriginal and Torres Strait Islander peoples to Country.

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Summary

1 The Commission has decided to make a more preferable draft rule to formalise AEMO's obligations relating to its current practice of co-optimising the volume of contingency frequency control ancillary services (FCAS) procured with the size of the largest credible contingency in dispatch. The more preferable draft rule includes a requirement for AEMO to use reasonable endeavours to undertake contingency size co-optimisation. It also introduces new reporting obligations to improve transparency related to how co-optimisation is being used. In addition, the Commission does not propose any change to the existing cost recovery arrangements in relation to contingency FCAS.

2 The draft rule is in response to two related issues raised by Grids Energy Pty Ltd (proponent). These were submitted as two separate rule changes, and the Commission has decided to consolidate the two requests due to their shared subject matter and common objective - to improve the National Electricity Market's (NEM) contingency FCAS frameworks.

3 AEMO procures contingency FCAS to maintain a secure power system in the event of a credible contingency, such as the sudden loss of a generating unit or transmission line. The volume of contingency FCAS procured in each dispatch interval is primarily determined by the size of the largest credible contingency. The NEM dispatch engine (NEMDE) determines dispatch outcomes by co-optimising energy and FCAS bids to meet demand at least cost while maintaining system security. However, under current arrangements, the size of the largest credible contingency is typically treated as an input to the dispatch process rather than a variable that can be adjusted to improve overall efficiency (i.e. co-optimised).

4 The first issue relates to whether a more efficient dispatch could be achieved through co-optimising the size of the largest credible contingency. In relation to this, the Commission considers that improvements to the design of co-optimisation constraints could theoretically improve FCAS price efficiency within the NEM. However, the Commission considers that:

- the benefit from expanding AEMO's current approach to optimising the largest credible contingency is likely to be small and concentrated in limited intervals, with limited benefits to be realised beyond what is already occurring through existing practices
- there are material implementation costs and risk considerations associated with the development of new constraints, particularly in the context of other reforms currently underway
- there is uncertainty as to whether market efficiency could be improved over time by expanding the use of co-optimisation constraints.

5 Therefore, the draft rule seeks to improve transparency in relation to contingency size co-optimisation by:

- formalising the requirement for AEMO to use reasonable endeavours to co-optimise the size of the largest credible contingency, in central dispatch
- requiring AEMO to set out how it will perform co-optimisation of the largest credible contingency in the constraint formulation guidelines
- requiring AEMO to report on the instances in which contingency size co-optimisation constraints are applied and, where applicable, AEMO's assessment of the impact of co-optimisation in maximising the value of spot market trade.

6 The second issue relates to considering whether changes to the contingency size cost recovery arrangement would be warranted. Specifically, to recover costs under a 'runway' cost recovery

arrangement, replacing the current arrangement of recovering costs in proportion to energy dispatch or consumption. The runway pricing proposal would allocate more contingency FCAS costs to units that contribute more to the size of the largest credible contingency. As part of its assessment, the Commission also considered alternative cost recovery arrangements.

7 The Commission does not propose any change to the existing cost recovery arrangements. The Commission notes that while the current cost recovery arrangements may not be fully cost-reflective they are well understood by participants. Further, the expected benefits of any change to these arrangements at this stage are limited, and are unlikely to outweigh the material costs, complexity and delivery risks associated with implementation.

8 We are seeking feedback on our draft determination and rule by **16 JULY 2026**.

The benefits of expanding current co-optimisation practices are modest

9 AEMO currently co-optimises the size of the largest credible contingency in dispatch, under the circumstances set out in AEMO's constraint formulation guidelines. AEMO undertakes this practice in accordance with its requirement to maximise the value of spot market trade.[1]

10 Many stakeholders recognised there are merits in expanding AEMO's current practice of co-optimisation to yield further market efficiency improvements. However, stakeholders also noted that co-optimisation has the potential to lead to increased volatility in contingency requirements, particularly during periods of high FCAS and energy prices, potentially creating market instability. Stakeholders therefore noted that the benefits should be traded off carefully with implementation costs and risks.

11 The Commission engaged ACIL Allen to provide an assessment of the benefits of expanding existing co-optimisation practices. ACIL Allen's modelling results - published alongside this report - identified that improvements to the design of co-optimisation constraints could improve FCAS price efficiency; however, overall improvements to efficiency are modest and likely to be concentrated in limited intervals.

12 In light of the stakeholder feedback and ACIL Allen's assessment, the Commission does not consider that mandating broader or routine co-optimisation in all circumstances in the rules is justified at this time, given the modest and uneven benefits identified as well as the implementation risks discussed above.

13 ACIL Allen suggests that costs could be minimised through implementing the approach directly into NEMDE, however the Commission understands that in practice, changes to NEMDE can often be a complex and costly task . While software changes may be simple, system verification and integration with supporting systems can be resource-intensive. The need for this should therefore be considered in the context of other reforms underway.

The draft rule is designed to enable continuous improvement of co-optimisation practices over time

14 The draft rule seeks to improve transparency around the use of co-optimisation in practice. The Commission considers that greater clarity and transparency would improve stakeholder visibility of AEMO's practices and allow for a more thorough consultation process on the development of the constraint formulation guidelines. The draft rule requirement for AEMO to include information on co-optimisation in its existing weekly and quarterly frequency performance reporting, would

1 NER, clause 3.4.1(a).

provide sufficiently granular visibility on co-optimisation practices. The Commission considers that this would promote a more considered assessment of the need to expand the application of contingency size co-optimisation over time, while avoiding disproportionate implementation costs and risks.

15 To give effect to the above outcome, the rule also introduces a transitional arrangement requiring AEMO to undertake a review of the co-optimisation arrangements under the constraint formulation guidelines, and complete this review process by 1 October 2028, taking into account the publication of weekly and quarterly reports under the draft rule.

16 The Commission is particularly interested in stakeholder feedback on the specific reporting requirements that would be most beneficial. The Commission envisages that weekly reporting would include quantitative information related to the dispatch intervals in which constraint sets relating to co-optimisation were applied to NEMDE and how often they are binding. In the quarterly report, the Commission proposes that AEMO provide a more qualitative assessment on whether co-optimisation could be applied more broadly.

The Commission does not propose to make changes to contingency FCAS cost recovery arrangements at this time

17 The Commission has decided not to pursue changes to contingency FCAS cost recovery arrangements at this time. This includes both the runway cost recovery approach proposed by the proponent, as well as alternative cost recovery methodologies, including hybrid runway models, frequency performance payments and deviation pricing. The Commission found these alternatives to be unsuitable, as they do not materially improve upon current arrangements or justify the associated costs and risks.

18 While a more cost-reflective cost recovery arrangement could improve incentives for participants to consider the capacity size of their investments on the volume of contingency FCAS required, the Commission considers that, in practice, such reforms would be complex to implement, and are unlikely to produce material benefits for consumers.

19 The Commission also sought ACIL Allen's analysis on this aspect of the rule changes, which found that since cost allocation is based on each participants' contribution to a fixed largest credible contingency, all participants face a financial incentive to reduce output in order to lower their cost exposure and avoid moving up the runway. However, a reduction in output from participants who are not part of the largest credible contingency would not affect the volume of contingency FCAS required. This analysis, as well as stakeholder feedback to date, indicates that implementing runway pricing, particularly in the absence of mandatory co-optimisation, could create incentives that tend to increase system costs, particularly during periods of scarcity.

20 The Commission considers that the draft rule provides a pathway for future consideration of cost-recovery reform, by improving transparency and the evidence base on how dispatch outcomes, FCAS procurement and system costs interact over time.

We assessed our draft rule against three assessment criteria, taking stakeholder feedback into account

21 The Commission has considered the NEO[2] and the issues raised in the rule change requests. We have assessed the draft rule against three assessment criteria outlined below.

2 Section 7 of the NEL.

22 The more preferable draft rule would contribute to achieving the NEO by:

- **Maintaining system, security and reliability outcomes** – The draft determination seeks to support system security and reliability relative to both the status quo and the original rule change proposal from Grids Energy, by clarifying AEMO's ability to co-optimise contingency requirements where appropriate, while preserving operational discretion and avoiding unintended security risks. In relation to contingency FCAS cost recovery arrangements, the Commission considers that the current arrangements remain appropriate from a system security perspective. Further, the Commission considers that improvements to transparency would support improved system security outcomes.
- **Improving market efficiency** - The draft rule is expected to promote more efficient market outcomes compared to both the status quo and more prescriptive reform options through increased transparency around co-optimisation practices, which are designed to provide sufficiently granular information to participants to support the improvement of these practices over time through the constraint formulation guideline consultation process.
- **Minimising implementation costs** - The draft determination supports the NEO by minimising implementation costs and delivery risks, relative to both the original proposals and alternative reform options, while still enabling incremental improvements in outcomes. The Commission's draft rule avoids material changes to NEMDE, constraint formulation, and FCAS settlement systems, avoiding costs, while still achieving benefits.

Implementation approach

23 The draft rule would be implemented on a staged basis to align with AEMO's existing reform priorities. If made as a final rule:

- provisions clarifying the requirement for AEMO to use reasonable endeavours to undertake co-optimisation would commence on 4 September 2026
- new transparency and reporting obligations would commence on 1 October 2027, allowing sufficient time for system build, automation and consultation.
- the transitional arrangements would require AEMO to complete a review of the constraint formulation guidelines by 1 October 2028.

How to make a submission

We encourage you to make a submission

Stakeholders can help shape the solution by participating in the rule change process. Engaging with stakeholders helps us understand the potential impacts of our decisions and contributes to well-informed, high quality rule changes.

How to make a written submission

Due date: Written submissions responding to this draft determination and rule must be lodged with Commission by **16 July 2026.**

How to make a submission: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code **ERC0359.**[3]

Tips for making submissions on rule change requests are available on our website.[4]

Publication: The Commission publishes submissions on its website. However, we will not publish parts of a submission that we agree are confidential, or that we consider inappropriate (for example offensive, defamatory, vexatious or irrelevant content, or content that is likely to infringe intellectual property rights).[5]

Next steps and opportunities for engagement

There are other opportunities for you to engage with us, such as one-on-one discussions or industry briefing sessions.

You can also request the Commission to hold a public hearing in relation to this draft rule determination.[6]

Due date: Requests for a hearing must be lodged with the Commission by 11 June 2026.

How to request a hearing: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code **ERC0359.** Specify in the comment field that you are requesting a hearing rather than making a submission.[7]

For more information, you can contact us

Please contact us with questions or feedback at any stage, noting the project code.

Email:	aemc@aemc.gov.au
Telephone:	(02) 8296 7800

3 If you are not able to lodge a submission online, please contact us and we will provide instructions for alternative methods to lodge the submission

4 See: https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/our-work-3

5 Further information about publication of submissions and our privacy policy can be found here: https://www.aemc.gov.au/contact-us/lodge-submission

6 Section 101(1) of the NEL

7 If you are not able to lodge a request online, please contact us and we will provide instructions for alternative methods to lodge the request.

Contents

1 The Commission has made a draft determination

This draft determination is to make a more preferable draft rule (hereafter 'draft rule') in response to two rule change requests submitted by Grids Energy Pty Ltd (proponent) seeking to enhance the efficiency of the existing contingency frequency control ancillary services (FCAS) framework. The Commission's draft determination is to:

- formalise AEMO's obligations relating to its current practice of co-optimising and improve transparency on the application of co-optimising the size of the largest credible contingency in dispatch (referred to throughout this paper as co-optimisation)
- retain the existing contingency FCAS cost recovery arrangements.

This Chapter provides a high-level summary of the rule change request and the Commission's draft decision. Chapters 2 to 4 provide further detail on the Commission's reasoning.

We are seeking feedback on this draft rule and draft determination. Submissions close **16 July 2026**.

1.1 We received two proposals for improvements to contingency FCAS arrangements

The proponent submitted a package containing two related rule change requests. However, the Commission has decided to consolidate the two rule change requests due to their shared subject matter and common objective - to improve the NEM's contingency FCAS frameworks. The proposals are summarised below:

- **ERC0359 – Optimising contingency size in dispatch:** proposes that co-optimising the size of the largest credible contingency by treating it as a variable as opposed to an input in the NEM dispatch engine (NEMDE), would help reduce the total costs of energy and FCAS procured. For more information, see: https://www.aemc.gov.au/rule-changes/optimising-contingency-size-dispatch
- **ERC0360 – Allocating contingency FCAS costs:** proposes a 'runway' cost allocation approach, which the proponent considers improves on the cost reflectivity of the current cost recovery arrangements. This method would concentrate costs on the largest generators or loads, whose potential loss defines the contingency size and drives the contingency FCAS requirement. For more information, see: https://www.aemc.gov.au/rule-changes/allocating-contingency-fcas-costs

1.2 Our draft rule clarifies and improves the transparency of co-optimisation

The Commission's draft rule seeks to clarify and improve transparency around co-optimisation of the largest credible contingency. The draft rule introduces a:

- reasonable endeavours obligation for AEMO to undertake contingency size co-optimisation in the central dispatch process
- requirement for AEMO to set out in the constraint formulation guidelines how it will perform co-optimisation
- requirement for AEMO to publish information on co-optimisation through the existing weekly and quarterly Frequency Performance and Time Deviation Monitoring report:
  - weekly report: instances where co-optimisation was applied in the previous week

- quarterly report: commentary on the impact of co-optimisation in the previous quarter.

The draft rule seeks to improve transparency and understanding of existing practices in relation to co-optimisation. The draft rule responds to stakeholder feedback that under the current arrangements, it can be challenging to observe and anticipate when co-optimisation of contingency FCAS requirements has been applied in dispatch outcomes, while taking into account the costs and risks of more extensive reform.

The Commission's detailed considerations in relation to the draft rule are set out in Chapter 3.

1.3 The Commission does not propose changes to contingency FCAS cost recovery arrangements

Under current arrangements, contingency FCAS costs are allocated broadly across participants based on their energy output or consumption, with limited regard to their role in determining the size of the contingency. The runway pricing proposal, instead allocates costs on a more incremental basis, with participants contributing in proportion to the extent to which their size increases the overall FCAS requirement. For further information on the runway pricing approach, refer to section 3.1 of the consultation paper.

In addition to the proponent's proposal for the Commission to consider a runway pricing mechanism, the Commission also examined a range of alternative cost recovery arrangements. This included:

- **Allocating a greater proportion of costs to the largest units only -** applying the runway cost recovery approach to only the unit or units which set the largest credible contingency. A similar approach can also be adopted by allocating contingency FCAS costs based on the shadow prices that would be determined if co-optimisation is applied in central dispatch.
- **Applying frequency performance payments -** costs would be allocated based on a participant's historical performance in responding to frequency deviations and measured through 'contribution factors'.
- **Applying deviation pricing -** costs would be allocated according to participants' real-time relative helpfulness or unhelpfulness in responding to frequency disturbances. That is, participants would be paid for responses that return the frequency into the required frequency band, and participants that cause deviations away from the required frequency band would incur a cost.

In considering the trade-offs for each cost recovery arrangement, the Commission's draft determination is not to amend the existing cost recovery arrangements for contingency FCAS.

The Commission's detailed considerations in relation to contingency FCAS cost recovery arrangements are set out in Chapter 4.

1.4 The Commission considered stakeholder feedback and sought technical advice

The Commission sought a wide range of inputs to inform this draft determination on the proposed rule changes, including:

- stakeholder views raised in submissions to the consultation paper and through a technical working group discussion
- insights from further stakeholder engagement, including areas of agreement and concern regarding co-optimisation and cost recovery arrangements

- independent analysis commissioned from ACIL Allen (and SW Advisory) to assess the costs, benefits and risks of the proposals.

The sub-sections below provide an overview of the key findings from each input, with further discussion of the inputs and how they informed the decision-making process set out throughout Chapters 3 and 4 of this paper.

1.4.1 Stakeholder feedback to the consultation paper

On 20 November 2025, the Commission published a consultation paper seeking feedback from stakeholders on the issues presented in both rule change proposals. A total of 17 submissions to the consultation paper were received.

Stakeholders raised a range of views on both proposals that the Commission has taken into account in this draft determination. Stakeholders particularly questioned the magnitude of potential benefits from the proposals and identified risks, given the transition, and emphasised the need for cost–benefit analysis and detailed studies to inform substantive changes to the current framework. Specifically, stakeholders:

- considered the current arrangements effective, describing them as generally transparent and predictable, enabling participants to understand their likely exposure and manage risk in ways that minimise market distortions.
- questioned whether the efficiency gains justified the proposed changes, given the relatively small value of contingency FCAS costs and the additional dispatch complexity the changes would introduce.
- emphasised the need for rigorous cost–benefit analysis and detailed studies to demonstrate the value of the proposed changes, given the risks involved.

1.4.2 The Commission conducted a technical working group meeting to seek further stakeholder input

The Commission decided to engage further with stakeholders on the technical merits of each proposal by establishing a technical working group (TWG). A TWG meeting was convened on 1 April 2026. The TGW included presentations from ACIL Allen on its key findings and AEMO on its submission to the consultation paper, and invited feedback on the proposals.

While perspectives at the TWG were varied, stakeholders generally expressed limited support for substantive reform. Stakeholders saw co-optimisation of the largest credible contingency as efficient in theory, and necessary in some circumstances, however expressed a need for greater transparency on when and why co-optimisation of the largest credible contingency is undertaken in practice. However, stakeholders raised a range of concerns regarding implementation cost and complexity, and interactions with existing market arrangements, noting:

- implementation is likely to be complex regardless of whether co-optimisation is implemented directly in central dispatch or via generic constraints
- there is currently limited understanding of how co-optimisation might adversely impact participants in ‘edge case’ market events.

Stakeholders generally agreed that current cost recovery arrangements are imperfect, but views differed on whether changes would improve outcomes. There was interest in narrow or hybrid approaches - such as applying runway pricing principles only to the largest credible contingency. Stakeholders viewed improvements to cost-reflectivity and incentives for efficient dispatch and investment as primary objectives if changes were made. For any proposed changes to cost recovery, stakeholders were vigilant about the unintended behavioural incentives and settlement impacts beyond FCAS.

1.4.3 ACIL Allen has been commissioned to provide analysis of the proposals

The AEMC has engaged ACIL Allen Consulting, supported by its subcontractor SW Advisory, to provide analysis to inform the Commission's consideration of the proposed rule changes. The analysis and findings presented by ACIL Allen (and SW Advisory) represent independent advice provided to the Commission and should not be construed as reflecting the views of the AEMC. This advice is one input to the Commission's broader assessment of the proposed rule changes. [8]

ACIL Allen's analysis is intended to provide insight into market outcomes under historical NEM conditions and to consider how those outcomes may evolve as the NEM transitions over the longer term. The scope of the work undertaken by ACIL Allen included analysis of the costs, benefits, and risks associated with implementing contingency size optimisation and runway pricing for contingency FCAS cost recovery arranangements in the NEM. The analysis also examined potential impacts on bidding and dispatch behaviour, financial outcomes for NEM participants, and any implications for contract markets arising from the proposed changes.

The final report - published on our website - makes the following key findings:[9]

- Co-optimising contingency FCAS requirements is an improvement to the current arrangements and would continue to be beneficial as the power system evolves. It would ensure AEMO procures a more efficient level of contingency FCAS in each dispatch interval and would provide clearer price signals by avoiding a reliance on other forms of frequency response such as mandatory primary frequency control availability in the system that occurs under the current approach.
- The primary economic benefit of co-optimisation arises from improved allocative efficiency, enabling more efficient joint use of energy and FCAS resources, increasing the value of spot market trading and, over time, leading to the most efficient settlement outcomes.
- Runway cost allocation is only beneficial if implemented alongside co-optimised contingency requirements, and should be carefully designed to assign costs to the causers of the marginal increment in contingency risk. Applying runway pricing without co-optimisation, or across all large generators, is likely to result in inefficient price signals and dispatch outcomes, while alternative 'causer pays' approaches based on marginal constraints may better align with market design principles.

8 The final report is published on the project website

9 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May 2026.

2 The draft determination would contribute to the energy objectives

2.1 The Commission must act in the long-term interests of energy consumers

The Commission can only make a rule if it is satisfied that the rule will or is likely to contribute to the achievement of the relevant energy objectives.[10]

For this rule change, the relevant energy objective is the NEO:

The NEO is:[11]

> 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; and
>
> (c) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

The targets statement, available on the AEMC website, lists the emissions reduction targets to be considered, as a minimum, in having regard to the NEO.[12]

2.2 We must also take these factors into account

2.2.1 We have considered whether to make a more preferable rule

The Commission may make a rule that is different, including materially different, to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule is likely to better contribute to the achievement of the NEO.[13]

For this rule change, the Commission made a more preferable draft rule. The reasons are set out in section 2.3 below.

2.2.2 We have considered whether to make a draft rule for the Northern Territory

The NER, as amended from time to time, apply in the Northern Territory, subject to modifications set out in regulations made under the Northern Territory legislation adopting the NEL.[14] Under those regulations, only certain parts of the NER have been adopted in the Northern Territory.

The more preferable draft rule **does not** relate to parts of the NER that apply in the Northern Territory. As such, the Commission has not considered Northern Territory application issues.

See Appendix C for more detail on the legal requirements for our decision.

10 Section 88(1) of the NEL.
11 Section 7 of the NEL.
12 Section 32A(5) of the NEL.
13 Section 91A of the NEL
14 These regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations 2016.

2.3 How we have applied the legal framework to our decision

The Commission must consider how to address the risk that existing contingency FCAS frameworks may no longer efficiently support the secure and cost-effective procurement of contingency FCAS as system conditions evolve, against the legal framework. This includes assessing whether it is necessary to revise the existing contingency FCAS arrangements to:

- require AEMO to expand its existing practise of optimising the largest credible contingency size in dispatch, as proposed under the *optimising contingency size in dispatch* proposal
- introduce a runway pricing cost allocation methodology to replace the existing cost recovery methodology, as proposed under the *allocating contingency FCAS costs* proposal.

We identified the following criteria to assess whether the proposed rule change, no change to the rules (business-as-usual), or other viable, rule-based options are likely to better contribute to achieving the NEO:

- **Safety, security, and reliability** - The rule change requests relate to the way in which dispatch minimises certain risks to system security, in particular, the size of the largest credible contingency. In making its draft rule, the Commission has considered whether the aim of the rule change would enhance system security by limiting the size of the largest credible contingency and, therefore, the size of the disturbances the system must remain secure against.
- **Principles of market efficiency** - The proponent views the rule change proposals as providing market efficiency benefits by directly minimising the amount and costs of FCAS required, and internalising FCAS costs into market processes through better signals for operation and investment. The Commission has considered the extent to which the draft rule would lead to different dispatch outcomes and, therefore, costs relative to outcomes under existing arrangements.
- **Implementation considerations** - The proposed rule changes have implementation considerations from the necessary changes in AEMO's systems, as well as the potential impact on the pace of the transition, should the reduction in dispatch lead to earlier thermal retirements or reductions in contract market liquidity. In making the draft rule, the Commission has considered implementation costs and risks to both AEMO and industry more broadly.

These assessment criteria reflect the key potential impacts – costs and benefits – of the rule change request, for impacts within the scope of the NEO. Our reasons for choosing these criteria are set out in Section 4 of the consultation paper. No changes were made to the criteria following consultation on the Consultation Paper, as no stakeholders raised substantive objections.

The Commission has evaluated the impacts of the various policy options against the assessment criteria, taking into account stakeholder submissions to the consultation paper, feedback from stakeholders that participated in the TWG, and inputs from ACIL Allen through its final report findings, which include quantitative analysis on the proposed changes.

The rest of this section explains why the draft rule best promotes the long-term interest of consumers when assessed against the three criteria set out above.

2.3.1 System security and reliability

The draft determination seeks to support system security and reliability relative to both the status quo and the original rule change proposals from Grids Energy, by clarifying AEMO's ability to co-optimise contingency requirements where appropriate, while preserving operational discretion and avoiding unintended security risks.

Optimising contingency size in dispatch

The draft rule improves security outcomes by formalising AEMO's obligations relating to its current practice of co-optimising the size of the largest credible contingency in dispatch. The draft rule sets out a 'reasonable endeavours' obligation on AEMO to undertake co-optimisation of the largest credible contingency. AEMO is required to provide guidance in the constraint formulation guidelines on the circumstances in which co-optimisation could be applied, which would include consideration of how co-optimisation would impact the secure operation of the power system, if invoked.

The Commission recognises the concerns raised by ACIL Allen that relate to the way in which co-optimisation is undertaken by AEMO. ACIL Allen identified two structural limitations in the current process for determining the largest credible contingency:[15]

- timing of information used, which relates to the largest credible contingency constraints relying on SCADA information available at the start of the dispatch interval. Where generator output, VRE conditions, or storage targets change materially within the interval, this approach may not reflect the actual largest credible contingency by the end of the period.
- incomplete recognition of available frequency response in determining the largest credible contingency, as AEMO does not account for the contingency and regulation FCAS that units may already be enabled to provide. This can distort the calculated contingency requirement.

As a result of these limitations, ACIL Allen considers AEMO may not enable sufficient contingency FCAS to match the largest credible contingency at times. However, the Commission agrees with ACIL Allen's finding that this does not usually result in system security issues as many units that are not enabled for FCAS still provide primary frequency response (PFR).[16] The Commission has set out its consideration of the market efficiency impacts of this issue in section 2.3.2.

Further details on how the draft rule would operate are provided in Chapter 3.

Allocating contingency FCAS costs

In relation to contingency FCAS cost recovery, the Commission considers that the current arrangements remain appropriate from a system security perspective. The Commission has not identified any concerns regarding system security and reliability under the current FCAS settlement arrangements.

The Commission acknowledges the view held by some stakeholders that runway pricing could penalise large synchronous generators while failing to recognise their provision of inertia, fault current and system strength, potentially creating incentives to reduce the availability of assets critical to security. However, the Commission agrees with ACIL Allen's finding that changes to contingency FCAS volumes are unlikely to affect the commitment decisions of large synchronous units or their provision of essential system services, as these decisions are driven primarily by energy market fundamentals rather than FCAS procurement.[17]

Despite this clarification, on balance, the Commission considers that changes to cost recovery would not materially improve security or reliability outcomes relative to the status quo.

15 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p. 17.
16 Ibid.
17 Ibid., p. 31.

2.3.2 Market efficiency

The draft determination is expected to promote more efficient market outcomes compared to both the status quo and more prescriptive reform options, while recognising that the magnitude of efficiency benefits identified to date is incremental.

Optimising contingency size in dispatch

The Commission's draft rule to clarify AEMO's discretion to co-optimise contingency requirements supports incremental improvements in allocative efficiency in specific dispatch intervals. ACIL Allen's analysis indicates that co-optimisation can reduce systematic over-procurement of contingency FCAS and enable more efficient joint use of energy and FCAS resources.[18] While these benefits are currently limited in scale and concentrated in particular system conditions, they are consistent with the requirement to maximise the value of spot market trading.[19]

The draft rule also seeks to improve predictability without materially altering dispatch behaviour. Stakeholders emphasised that the current arrangements are well understood and that abrupt or mandatory changes could introduce uncertainty and inefficient bidding responses. The draft rule requires AEMO to provide guidance in the constraint formulation guidelines to clarify when co-optimisation may be applied, rather than mandating its use in all instances. Therefore, the draft rule supports efficiency by reducing regulatory ambiguity and avoiding unnecessary disruption to established bidding and dispatch incentives.

The Commission considers that improved reporting and transparency provides a pathway for evidence-based evolution of co-optimisation practices. Enhanced information on the use and effects of co-optimisation will allow future assessment of co-optimisation practices through rules consultation processes on the constraint formulation guidelines. This would support continuous improvement as system conditions change, leading to consideration of market efficiency outcomes from co-optimisation over time.

Allocating contingency FCAS costs

The Commission considered stakeholder proposals to reform contingency FCAS cost recovery, including runway pricing and alternative approaches. On balance, the Commission considers that these options are unlikely to materially improve market efficiency. Stakeholders noted that contingency FCAS costs currently comprise a relatively small and declining share of wholesale costs, limiting the potential efficiency gains from reallocation. ACIL Allen's analysis further indicates that applying a full runway methodology across all generators may distort dispatch incentives, particularly by exposing large units (that are not the largest credible contingency) to high FCAS costs without reducing the underlying contingency requirement.[20]

The Commission also explored the merits of a revised runway approach where only the unit(s) contributing to the setting of the largest credible contingency in the dispatch interval are allocated costs under the runway method, with all other costs smeared across remaining participants. While this approach may sharpen incentives for the marginal causer, the Commission considers that its benefits would likely be narrow, largely indirect and uncertain in magnitude. Any efficiency gains would be limited to a small number of high-price intervals and may not be consistently realised, with further uncertainty as to whether these gains would be passed through to consumers. These effects are compounded by the small cost base of contingency FCAS, which represents only a

18 Ibid., p. 8.

19 NER, clause 3.8.1(a).

20 ACIL Allen, Contingency size co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May 2026, p. 17..

minor share of wholesale energy costs, such that any overall impact on market outcomes is likely to be limited.

The Commission discusses these approaches and the rationale for its determination further in Chapter 4.

2.3.3 Implementation considerations

The draft determination supports the NEO by minimising implementation costs and delivery risks, relative to both the original proposals and alternative reform options, while still enabling incremental improvements in outcomes.

Optimising contingency size in dispatch

The Commission's draft rule avoids material changes to NEMDE, constraint formulation, and FCAS settlement systems, significantly reducing systems development, testing, and assurance requirements. This responds to stakeholder concerns about implementation complexity and delivery risk.

The proposed transparency and reporting requirements are designed to be delivered through existing AEMO publications and processes, limiting additional systems investment and reducing the risk of unintended operational consequences. Allowing flexibility in how reporting is implemented enables AEMO to integrate these obligations efficiently while meeting the policy intent.

Allocating contingency FCAS costs

The Commission considered the implementation costs of alternative cost recovery arrangements, including runway pricing and related methodologies. While the Commission has not sought formal implementation advice from AEMO, it understands that implementation costs associated with changes to settlement arrangements are likely to be comparable to the recent Frequency Performance Payments reforms. In this context the Commission estimates that implementation costs for implementing changes to contingency FCAS cost allocation to be in the order of $2–3 million. The Commission notes that while AEMO has increased familiarity with such processes, this would not materially reduce the need for supporting studies, system testing and verification to manage delivery risk. On balance, the Commission considers that these costs are disproportionate to the likely benefits, and that implementing such reforms would add complexity without materially improving outcomes.

Further, the Commission considers that preserving current cost recovery arrangements avoids creating new behavioural incentives or settlement risks that could undermine contract market liquidity or contribute to inefficient asset exit. Stakeholders broadly expressed little appetite for significant reform to existing FCAS arrangements, noting a fatigue from an extensive frequency reform program over the past decade.

3 The draft rule clarifies and improves the transparency of co-optimisation

The Commission's draft rule is a proportionate and targeted response to the issues raised by stakeholders in relation to the proponent's proposal to optimise the size of the largest credible contingency in dispatch. The draft rule formalises AEMO's obligations relating to its current practice of co-optimising the largest credible contingency, and introduces targeted transparency measures to improve stakeholder understanding of when co-optimisation is applied, and whether its application could be expanded. The Commission considers that this approach preserves operational flexibility for AEMO, minimises implementation risk and cost, and enables improvement over time as system conditions evolve.

This chapter explains how the draft rule operates. It sets out:

- the current arrangements and approach to co-optimising the largest credible contingency
- the evidence on potential benefits and limitations of expanding AEMO's current practices of co-optimising the size of the largest credible contingency
- stakeholder views regarding transparency, predictability, implementation complexity and cost of proposed reforms
- how the draft rule functions and responds to issues raised by stakeholders.

3.1 AEMO currently co-optimises contingency size under existing dispatch obligations

The NER establish a framework under which AEMO is required to operate and maintain the power system in a secure, safe and reliable manner, while also promoting efficient outcomes in the National Electricity Market (NEM). In particular, the Rules require AEMO to operate the central dispatch process to maximise the value of spot market trading, subject to power system security requirements. Within this framework, the Commission understands that while there are no explicit requirements on AEMO to co-optimise the size of the largest credible contingency, AEMO:

- undertakes contingency size co-optimisation in specific circumstances, consistent with its obligations to maximise the value of spot market trading[21]
- sets out the circumstances in which co-optimisation is applied through updates to the constraint formulation guideline.[22]

The Commission considers that while AEMO has both the capability and discretion under the current Rules to optimise contingency size in dispatch, the circumstances in which this occurs, and the way it is reflected in dispatch outcomes, are not explicitly articulated in the Rules and are not always transparent to stakeholders. The current arrangements are explored further in the sections below.

3.1.1 Co-optimisation is consistent with AEMO's requirement to maximise the value of spot market trade

Clause 3.8.1(a) of the NER requires AEMO to operate a central dispatch process to balance supply and demand, using reasonable endeavours to maintain power system security and to maximise the value of spot market trading:

21 NER clause 3.8.1(a).
22 NER clause 3.8.10(c).

> *AEMO* must operate a *central dispatch* process to *dispatch scheduled resources* and *market ancillary services* in order to balance *power system supply* and demand, using its reasonable endeavours to maintain *power system security* in accordance with *Chapter 4* and to maximise the value of *spot market* trading on the basis of *dispatch bids*.

Clause 3.8.1(b) further explains that maximising the value of spot market trading involves maximising the value of electricity consumption, less the combined cost of electricity production, wholesale demand response, market network services and market ancillary services, subject to a range of physical and security constraints.

In its report to the Commission, ACIL Allen explains that the value of spot market trading is a measure of producer–consumer surplus generated by spot market transactions.[23] In a dispatch context, this surplus is maximised where energy and ancillary services are jointly optimised such that the marginal cost of providing those services is minimised, subject to maintaining system security.

This objective is implemented in practice through the National Electricity Market Dispatch Engine (NEMDE), which solves a linear optimisation problem in each dispatch interval. NEMDE determines the objective function value for each dispatch interval by aggregating the dispatched energy and ancillary services quantities multiplied by the bid prices for each dispatchable unit (including storage).

Contingency FCAS procurement costs form part of the overall costs that AEMO is required to consider under this objective. Where changes to energy dispatch affect the size of the largest credible contingency—and therefore the quantity of contingency FCAS required—there is a direct interaction between energy costs and FCAS costs. Co-optimisation of contingency size is therefore relevant to AEMO's obligation to maximise the value of spot market trading, because reducing contingency size at times of high FCAS prices may increase total welfare (producer–consumer surplus) where the FCAS cost savings exceed the incremental energy costs.[24]

3.1.2 AEMO recently updated its guidelines to apply co-optimisation

The constraint formulation guidelines provide a transparent, consultative framework through which AEMO provides guidance on its application of network constraint equations. Clause 3.8.10(c) requires AEMO to publish and maintain the constraint formulation guidelines. Updates to the constraint formulation guidelines are subject to the Rules consultation procedures. Clause 3.8.10(b) requires AEMO to determine and represent network constraints using a formulation that is fully co-optimised:

> Subject to paragraph (e), *AEMO* must determine and represent *network constraints* in *dispatch* which may result from limitations on *intra-regional* or *inter-regiona l* power flows and, in doing so, must use a *fully co-optimised network constraint formulation*.

In practice, a fully co-optimised constraint involves formulating constraints such that variable terms are placed on the left-hand side of the constraint equation, allowing NEMDE to optimise inputs against a fixed requirement on the right-hand side. This enables NEMDE to optimise generator dispatch, load and interconnector flows simultaneously to manage network limits at

23 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p. 11.

24 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, pp.11-12..

least cost.[25] AEMO is also required to specify circumstances where a fully co-optimised formulation is not appropriate (these are called alternative constraints).[26]

Box 1: Variables passed to the left-hand side of the constraint equation are optimised in dispatch

Constraint equations represent physical, security and operational limits that must be respected in dispatch in order to maintain a secure power system. As described in the constraint formulation guidelines, constraint equations are formulated with three key elements:

- a left-hand side (LHS), consisting of controllable variables such as generator dispatch, interconnector flows or aggregated FCAS quantities
- an operator (for example, ≤ or ≥)
- a right-hand side (RHS), representing a fixed requirement or limit that cannot be optimised by NEMDE.

Variables placed on the LHS are decision variables that NEMDE can optimise. Placing a greater number of relevant variables on the LHS provides NEMDE with greater degrees of freedom and increases the number of feasible solutions available to meet a given constraint, allowing the dispatch engine to compare the economic impacts of alternative dispatch outcomes.

By contrast, variables placed on the RHS are treated as fixed inputs to the optimisation. For FCAS constraints, the RHS typically represents the required quantity of a particular ancillary service, calculated outside NEMDE and passed into the dispatch engine prior to each run.

Source: AEMO, 2025. Constraint formulation guidelines. p.6-7.

The Commission notes that the framework under clause 3.8.10, which sets out the requirement for AEMO to develop the constraint formulation guidelines, refers only to the documentation of network constraintsand does not explicitly extend to co-optimisation of the constraints that determine the largest credible contingency. However, the current version of the constraint formulation guidelines provides commentary on the formulation of non-network constraint formulations, including FCAS. In the 2023 consultation on the constraint formulation guidelines, AEMO addressed a proposal from Grid Energy's rule change request to consider co-optimisation of the largest credible contingency. In the final report on the constraint formulation guidelines, AEMO noted that, given this rule change had been submitted to the AEMC, it was preferable to avoid parallel changes to the constraint formulation guidelines that could duplicate or pre-empt Commission decisions.[27]

Notwithstanding this, AEMO updated section 6.5 of the constraint formulation guidelines to provide clearer guidance on when generator output is currently co-optimised with FCAS requirements. These examples focus on system-security-driven circumstances in which available FCAS is insufficient, and co-optimisation effectively reduces contingency size to maintain a secure operating state. Documented cases include islanding scenarios (e.g. in SA and QLD) and reclassified or combined generator contingencies in which the effective contingency size exceeds the largest single unit.[28]

25 AEMO, 2025. Constraint formulation guidelines. p.10.
26 NER clause 3.8.10(c).
27 AEMO, 2023. Final report - standard consultation for the NEM, Constraint formulation guidelines. pp.9-13.
28 AEMO, 2025. Constraint formulation guidelines. pp.22-23.

3.1.3 Mathematical formulation for co-optimising the size of the largest credible contingency

Contingency FCAS maintains power system frequency stability following disturbances, such as the unplanned loss of a generator, load, or network element, known as contingency events. These services respond rapidly to correct the imbalance in active power caused by such events, arresting frequency deviations and restoring system frequency to approximately 50 Hz.

The volume of contingency FCAS procured is generally the largest creible contingency operating in the dispatch interval, equal to the maximum unit size dispatched in that trading interval, adjusted for load relief and, in some cases, inertia.[29] Under current arrangements, AEMO typically determines the largest credible contingency as SCADA measurements of unit output at the start of each dispatch interval. These values are then set as the FCAS requirement (i.e. the RHS value of the contingency FCAS constraints). Box 2 sets out the mathematical formulation under the current approach to determining the largest credible contingency.

Box 2: The current approach to determining the size of the largest credible contingency

Under the current approach, for the 6 second, 60 second and 5 minute contingency raise services, the largest credible contingency is usually set as the maximum SCADA-measured energy output of any generating unit, j, in the relevant region or group of regions. Mathematically, this can be expressed as:

$$LargestContingency = Max[SCADA_{energy}(j, T-5)]$$

where the SCADA measurement is taken at the start of the dispatch interval, at time, *T-5*, where, *T*, is the end of that dispatch interval.

The contingency FCAS requirement also considers counteracting factors such as load relief. For example in raise contingency FCAS services, the 6 second and 60 second contingency FCAS requirements are calculated as:

$$FCASrequirement = LargestContingency - Load\ Relief$$

The quantity of FCAS enabled under a non-co-optimised scenario, in a region, a, by FCAS service type, x, for time t, can be set out in the following general form:

$$TotalFCAS(a, x, t) = \sum_{j \in U_a} FCAS(j, x, t) \geq FCASrequirement$$

NEMDE then determines the units enabled for contingency FCAS by trading-off bids for FCAS and energy, and taking into account the units' FCAS trapezium.

The constraint formulation guidelines note additional features of FCAS constraint formulation, including:

- substitution of regulation FCAS for 5-minute contingency services
- incorporation of inertia for 1-second contingency services
- specialised formulations for separation risks, islanding and major interconnectors such as Basslink.

Source: Mathematical formulations based on ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, pp. 14-15.

As set out in Box 4, when co-optimisation is not undertaken, AEMO provides the *FCASrequirements*, from the SCADA information, to NEMDE. However, when using co-optimisation

29 AEMO, 2025. Constraint formulation guidelines. pp.16-18.

to determine the FCAS requirements, NEMDE would be used to simultaneously determine the optimal unit dispatches and the associated FCAS requirements, instead of AEMO providing the requirements as inputs to NEMDE. Co-optimising FCAS requirements becomes a decision variable rather than an input parameter. [30]

ACIL Allen explains that conceptually, the amount of raise contingency FCAS service, *x*, must cover, is for the loss of any generator. To cover the loss of generator j, the total amount of FCAS enabled for all of the other generators must be greater than the energy dispatch of generator, *j*, over the dispatch interval, *[T-5,T]*. If we ignore the impact of load relief, inertia and regulation, this becomes:[31]

$$\sum_{k \notin j} FCAS(k,x,t) \geq EnergyGen(j,t)$$

where, *FCAS(k,x,t)* is the enabled raise service from generator *k*, and *EnergyGen(j,t)* is the energy generation for unit j over the interval *[T-5,T]*.

The FCAS requirement can then be determined through NEMDE (ignoring other impacts) as:

$$\sum_{k} FCAS(k,x,t) \geq FCASRequirement(x,t) = LargestContingency(x,t)$$

This would mean NEMDE determines the optimal FCAS requirement, based on the energy generated by the unit in the dispatch interval. The optimised FCAS requirement can then be passed to the FCAS constraint, for NEMDE to determine the optimal units to dispatch for frequency, noting frequency services are already co-optimised with energy.

For further information on the co-optimisation formulation approach, refer to the ACIL Allen final report.[32]

3.2 Stakeholder feedback and technical advice informs the Commission's draft determination

While the existing Rules framework permits co-optimisation of the largest credible contingency in dispatch, there is no explicit requirement for AEMO to undertake this practice. As identified in section 3.1.3, contingency FCAS requirements are generally determined outside NEMDE, using SCADA information at the start of the dispatch interval, which is then passed to the dispatch engine via constraint equations. This has contributed to uncertainty among stakeholders about when and why co-optimisation is undertaken and how it interacts with AEMO's broader system security obligations.

The Commission sought a range of stakeholder feedback in considering its draft determination. This included receipt of 17 submissions to the consultation paper, published 18 November 2025, and the establishment of a TWG, which convened on 1 April 2026. The Commission also sought technical economic advice from ACIL Allen, and its sub-contractor SW Advisory. ACIL Allen's findings are published on our website.

The sections below set out the Commission's consideration of stakeholder concerns and advice from ACIL Allen, in making its draft rule determination.

30 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p. 15.
31 Ibid.
32 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, pp. 14-17.

3.2.1 Expanding co-optimisation may provide incremental system benefits

ACIL Allen's report indicates that, in principle, co-optimising the size of the largest credible contingency can improve allocative efficiency by allowing the dispatch process to trade off energy and FCAS costs more directly.[33] The results of historical modelling conducted by ACIL Allen over FY25, suggested that co-optimisation could:

- reduce contingency FCAS requirements by a small amount on average
- increase overall market efficiency by improving the value of spot market trading
- deliver benefits that are concentrated in a limited number of intervals, typically under tight system conditions.

Importantly, the modelling indicates that:

- the incremental efficiency benefits beyond AEMO's existing practice are small in magnitude
- benefits are highly concentrated in certain periods rather than widespread across dispatch intervals
- many potential benefits are already captured, through AEMO's current application of co-optimisation, in particular, during security-driven circumstances.

ACIL Allen considers that the primary benefit from co-optimisation is derived from an improvement in pricing efficiency

ACIL Allen's analysis indicates that the current approach to determining the largest credible contingency can result in contingency FCAS being over-procured, leading to inefficient pricing outcomes.[34] While current arrangements generally remain secure, ACIL Allen considers that these inefficiencies are likely to become more pronounced as the power system becomes more dynamic. ACIL Allen concludes that these issues could be resolved through co-optimisation of contingency size, particularly if implemented directly within NEMDE rather than through generic constraint formulations[35]

ACIL Allen has identified two structural limitations in the current constraint formulation approach for determining the largest credible contingency. The first issue relates to the timing of information used. Largest credible contingency constraints rely on SCADA information available at the start of the dispatch interval. Where generator output, VRE conditions, or storage targets change materially within the interval, this approach may not reflect the actual largest credible contingency by the end of the period.[36]

The second issue concerns the incomplete recognition of the available frequency response. In determining the largest credible contingency, AEMO does not account for contingency and regulation FCAS that units may already be enabled to provide. ACIL Allen considers that in the event this unit trips off, any contingency FCAS that the unit is enabled to provide would trip off as well, which could result in instances where there is insufficient contingency FCAS available following the trip.[37]

As a result of these limitations, ACIL Allen considers that AEMO may not be able to enable sufficient contingency FCAS to match the largest credible contingency at times. However, the Commission agrees with ACIL Allen, that this **does not result in system security issues** because

33 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p. 8.
34 ACIL Allen, 2026, pp. 8, 32.
35 ACIL Allen, 2026, p. 5.
36 ACIL Allen, 2026, p.18.
37 Ibid.

many units that are not enabled for FCAS still provide primary frequency responses (PFR), for example as a requirement under the mandatory primary frequency response arrangements. ACIL Allen considers that the approach of relying on non-enabled services to ensure sufficient services are available lacks transparency, and most likely results in excess contingency services being acquired a significant portion of the time (available non-enabled plus enabled services). ACIL Allen argues that co-optimising the largest credible contingency through NEMDE would reduce over-procurement by better accounting for changes in dispatch targets and the contingency and regulation services provided by the largest units, improving price signals and transparency.[38]

ACIL Allen expects these issues to become more material as system conditions evolve, including:[39]

- increasing penetration of fast-response technologies (e.g., BESS and pumped hydro) could mean that the current state of units, based on their SCADA measurements at the start of the dispatch interval, could be quite different from their energy targets at the end of the dispatch interval
- increased network-driven contingencies, including REZ connections, Marinus Link, and planned outages on key transmission elements
- greater interval-to-interval variability driven by local VRE conditions and storage dispatch targets.

The Commission considers that there is a material volume of non-enabled mandatory PFR in the system, arising from PFR obligations for registered scheduled and semi-scheduled generators under the NER.[40] Mandatory PFR requires generators to respond only when physically able - it does not require units to maintain headroom to deliver that response. As a result, non-enabled PFR cannot be relied upon with certainty at the time of a contingency event (e.g. when units are at full output or fuel-constrained, including variable renewable generation).

Mandatory primary frequency response is also only required to operate within a very narrow deadband, which is much narrower than the deadband through which contingency FCAS operates.[41] AEMO must therefore continue to procure a baseline level of enabled contingency FCAS, regardless of estimates of non-enabled PFR, to ensure the system remains secure. This limits the extent to which co-optimisation can reliably reduce contingency FCAS volumes, meaning some degree of apparent "over-procurement" is structural rather than inefficiency-driven. The Commission also notes that non-enabled PFR is not cost-free — it is remunerated through the primary frequency response incentive arrangements — reinforcing the need for caution in assuming excess "free" supply.

Therefore, the Commission considers that the existence of non-enabled PFR means that co-optimisation alone cannot fully resolve concerns about contingency FCAS volumes or costs and that targeted transparency and improved information may address clarity concerns more proportionately than prescriptive changes through co-optimisation.

The benefits of expanding co-optimisation beyond AEMO's current practice are modest, however could

38 Ibid.

39 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p.37.

40 NER clause 4.4.2.

41 The frequency operating standard sets the primary frequency control band (PFCB) as 49.985 – 50.015 Hz. The PFCB relates to the sensitivity for the provision of mandatory primary frequency response.

increase overtime

ACIL Allen conducted a historical modelling to estimate the changes in the value of spot market trading had the contingency requirement been co-optimised for the largest generator contingency in financial year 2025. ACIL Allen assessed the potential benefits above the status quo, in the case where co-optimisation is applied across all dispatch intervals over FY2025.

ACIL Allen assessed the following benefits:[42]

- the total welfare benefit, which estimates the producer and consumer surplus, measured through changes in the NEMDE objective function.
- changes in total energy and FCAS settlement costs, reflecting the consumer surplus benefit only.

ACIL Allen highlights that the total welfare benefit is considered a stronger approximation of the benefit of co-optimisation, as it accounts for changes in resource allocation resulting from co-optimisation.

Box 3: Assessing the welfare benefit

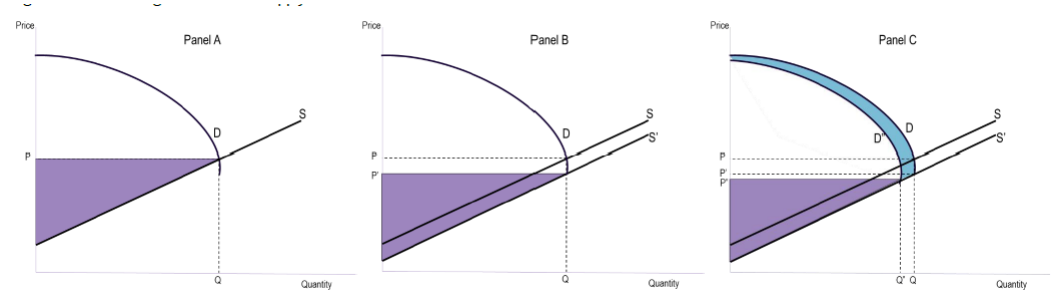
The value of spot market trade is a measure of the welfare, or producer-consumer surplus generated by spot market transactions. The producer-consumer surplus is measured by the area under the consumer demand curve (the aggregate of what consumers are willing to pay for energy market services), but bounded by the supply curve (the aggregate of the cost of generation-related services available to be supplied to the market).

In the figure below, Panel A, the generator supply curve S intersects the consumer demand curve D with price set at P for quantity Q. Consumers pay, and generators receive, price $P/MWh for quantity Q MWh delivered to the market. The producer-consumer surplus is the area between the curves (the coloured triangle (producer surplus) and the clear area between the triangle and the demand curve D (consumer surplus).

In Panel B, the reduction in supply costs shifts the supply curve from S to S' and lowers the price to P'. In this example, the producer surplus is largely unchanged, while the consumer surplus increases, so total welfare increases. The demand curve is deliberately drawn vertically on the right-hand side, reflecting little or no price elasticity of demand for the marginal consumers.

Panel C represents an adjustment to avoid acquiring excess services and is explained under "Acquiring excess services" below.

Figure 3.1: Changes in welfare as supply costs are lowered



Source: ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p.12.

For contingency FCAS services, AEMO sets the requirement (demand). Where AEMO acquires services that are in excess of the optimal requirement, reducing the demand will pull the demand

42 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p. 5.

curve to the left from D to D" as shown in the figure above, Panel C, which will reduce the overall producer-consumer surplus. However, the original curve representing excess to the optimal requirement is not a true representation of the requirement. The blue-shaded area in Panel C represents a loss of allocative efficiency rather than a contribution to the producer-consumer surplus, as the excess demand has no utility. Adjusting the contingency FCAS requirement to the optimal amount overcomes this efficiency loss.

Source: ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p. 11-12.

The results over the FY2025 period show (as an example relating to order of magnitude): [43]

- a $255,000 increase in welfare benefits across the year.
- $1.37 million increase in settlement costs above the status quo:
  - This outcome was driven by periods of high FCAS and energy prices in August 2024 and June 2025.
  - Excluding these periods, the settlement costs reduce by $3.8 million from the status quo.
  - On average, co-optimisation reduced contingency FCAS requirements by around 9 MW per dispatch interval.

ACIL Allen also considers that the benefits of co-optimisation could increase over time. ACIL Allen notes that while large thermal generators are exiting, the largest contingencies are not expected to fall, as:[44]

- some large units, such as Kogan Creek are expected to remain in the system beyond 2040
- network-driven contingencies are expected to become more prevalent as REZ transmission expands.

ACIL Allen also notes that BESS may also increasingly provide contingency FCAS, particularly in and around REZs, but as energy-constrained resources, they rely on efficient dispatch outcomes rather than FCAS revenues alone.[45]

The Commission considers that while the results indicate that there is potential to expand AEMO's existing practice of co-optimisation, the cost and risks of implementation are likely to be a driving factor for whether a rule should require AEMO to broaden its existing practice. The results indicate that the net benefits of co-optimisation, beyond AEMO's current practice are small, with large benefits concentrated in a limited number of intervals.

The Commission recognises that there may be scope for the benefits of co-optimisation to grow over time as the size of the largest contingency is unlikely to reduce into the future. However, the Commission also notes that FCAS costs have fallen considerably since the commencement of the very fast contingency FCAS markets in 2023. While contingency sizes may increase, the reduction in FCAS costs could mean benefits remain modest over time.

3.2.2 Expanding co-optimisation could increase implementation complexity and cost

A key issue raised through stakeholder submissions to the consultation paper and discussion with TWG members, relates to the implementation of co-optimisation and the associated costs and risks. There are two ways in which co-optimisation can be implemented:

43 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p. 24-36.

44 ACIL Allen, 2026, p. 37.

45 Ibid.

- generic constraint formulation (the Commission understand this is the current approach AEMO uses to implement co-optimisation)
- directly through central dispatch (this is the approach recommended by ACIL Allen).

ACIL Allen recommends that co-optimisation is implemented directly through central dispatch

ACIL Allen suggests that co-optimisation is best implemented directly within NEMDE through changes to the mathematical formulation of contingency requirements. ACIL Allen highlights that implementation via generic constraints would involve hundreds of constraints that would require ongoing, regular maintenance, that could prove costly over time.[46]

If implemented in NEMDE, AEMO would only require implementing the largest contingency constraints corresponding to general mathematical equations, similar to that set out in section 3.1.3. NEMDE would then automatically formulate the required set of constraints at each node, based on the general equation. ACIL Allen considers that data input requirements would be minimal as NEMDE already takes in the required inputs for co-optimsation.[47]

ACIL Allen also considers that implementation through NEMDE would provide for clearer, and more structured documentation, under clause 3.8.4(d), noting that while generic constraints are published, they are complex formulations that are poorly documented and difficult to access. [48]

The Commission understands there are material costs and risks in implementing changes through central dispatch

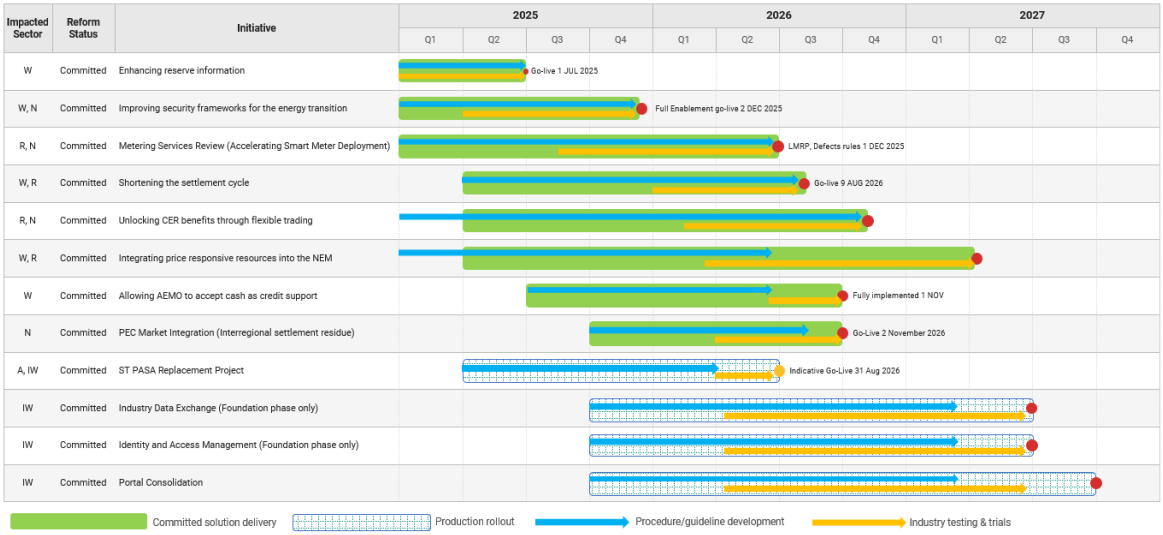
While the Commission has not sought specific implementation advice on the expansion of AEMO's current practice of co-optimising the largest credible contingency, the Commission understands from AEMO that:

- its current practice relies on generic constraint formulation to preserve operational flexibility and operator visibility
- embedding co-optimisation logic directly within NEMDE would introduce system-wide changes, testing and assurance requirements, ultimately leading to increased risk and cost
- changes to NEMDE tend to have flow-on impacts to linked systems, increasing delivery cost.

The Commission recognises that there are material implementation challenges in expanding the current practice of co-optimisation, whether that is through generic formulations or directly through NEMDE. The Commission understands that while software changes may be relatively simple, system verification could be resource-intensive and should be considered in the context of other reforms underway. The Commission also understands AEMO has a pipeline of committed market reform projects till mid 2027, as set out in Figure 3.2.

46 ACIL, Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May 2026, p.18.
47 Ibid.
48 Ibid.

Figure 3.2: AEMO has a pipeline of market reform project till mid 2027



Source: AEMC, 2026, based on AEMO NEM implementation road map, version 6.

Stakeholders called for any changes to the co-optimisation of the largest credible contingency to balance benefits with costs and risks

Stakeholder feedback to the consultation paper noted that changes to NEMDE and the constraint formulation are non-trivial, and that costs and risks may outweigh the limited benefits without strong safeguards and clear thresholds. This was noted in submissions from AEC, CS Energy and Stanwell.

The AEC and CEC noted that implementation "is likely to be complex and costly due to the need for individual FCAS constraint equations to be written for each large unit within the NEM Dispatch Engine"[49] [50]CS Energy also noted that "NEMDE is already experiencing delay issues under specific circumstances and additional optimisation processing is likely to compound this issue."[51]

AEC requested "that AEMO provide a cost estimation of the implementation as part of the consultation process". [52] The Commission has not sought formal implementation advice from AEMO, as this would require in-depth scoping of the requirements. Instead, the Commission has engaged with AEMO and the TWG to explore the risks and costs of implementation. The Commission has also given consideration to implementation costs associated with similar changes in making its draft determination.

Stakeholders that supported co-optimisation noted that the benefits should be proportionate to costs, applied narrowly, and integrated with broader FCAS and cost-allocation reforms. Hydro Tasmania noted in its submission to the consultation paper that "while we are aligned with the principles underpinning these proposals, we encourage the AEMC to consider the materiality of the benefits relative to the costs involved to ensure that any changes deliver proportionate benefits." [53] Powerlink highlighted the need to integrate changes to co-optimisation with broader FCAS reforms, noting "co-optimising energy and contingency FCAS in dispatch, where it enhances

49 AEC, submission to the consultation paper, 18 December 2025. p.2.
50 CS Energy, submission to the consultation paper, 18 December 2025. p.3.
51 Ibid.
52 AEC, submission to the consultation paper, 18 December 2025. p.2.
53 Hydro Tasmania, submission to the consultation paper, 18 December 2025. p.2

market outcomes, aligns with our desire to get the most out of our assets to the benefit of customers."[54]

The Commission considers that further work may be required to enable continuous improvement of NEMDE over time

Changes to NEMDE are inherently complex and risky, reflecting an ageing platform, interdependencies with multiple systems, and the absence of a sustained program of continuous improvement. ACIL Allen highlights that AEMO's NEMDE and related generic constraint-based systems appear to have had little development since the commencement of the NEM in 1998.[55]

The Commission recognises that NEMDE could benefit from a more fundamental redesign to align with advancements in the capability and performance of market systems used globally. However, the Commission highlights that this type of reform falls outside the immediate scope of this rule change request process and is not considered in detail in this draft determination.

The Commission will continue to engage with AEMO, beyond this rule change process, to better understand the challenges in enabling continuous improvement of NEMDE reform over time.

3.2.3 Stakeholders raised concerns that co-optimisation could increase dispatch volatility and result in adverse market outcomes

The Commission has considered a range of feedback from stakeholders through submissions to the consultation paper and the TWG meeting relating to concerns around the incentives and behavioural impacts of co-optimisation, including:

- increased dispatch volatility if the largest credible contingency changes frequently
- incentives created for defensive bidding or rebidding behaviour in edge cases
- increased difficulty in forecasting dispatch and price outcomes.

Stakeholders including Delta, CS Energy, AGL and EnergyAustralia expressed that explicitly introducing a requirement to optimise the contingency size could weaken the relationship between bidding, dispatch and revenue outcomes, making dispatch and price outcomes more difficult to anticipate and explain. Delta Electricity expressed that co-optimisation could introduce "a new and discretionary intervention into energy market outcomes", weakening the link between bids and dispatch and "increasing basis and volume risk for contracts" [56]. Delta further stated that reducing the predictability of dispatch outcomes "undermines confidence in market outcomes" and increases the risk of unintended behavioural responses.[57]

Similarly, EnergyAustralia raised concerns that frequent changes to the largest contingency setter could increase dispatch volatility and make financial exposure more difficult to forecast. EnergyAustralia noted that "frequent switching of the largest contingency setting can influence dispatch targets and offer incentives for participants to alter availability or bid strategically" and may result in "difficulty forecasting FCAS requirements".[58] Stakeholders including AGL and ENGIE also emphasised that reducing transparency and predictability in FCAS costs and dispatch outcomes would make it more challenging for participants to manage commercial risk in a transitioning market.[59] [60]

54 Powerlink, submission to the consultation paper. 18 December 2025. p.2.
55 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p. 38.
56 Delta Electricity, submission to consultation paper, 18 December 2025, p.1
57 Ibid.
58 EnergyAustralia, submission to consultation paper, 17 December 2025, p.3
59 AGL, submission to consultation paper, 15 December 2025, p.1.
60 ENGIE, submission to the consultation paper, 18 December 2025. p.1.

Origin, Delta, Stanwell and EnergyAustralia suggested that participants may rebid defensively, withhold capacity or operate more conservatively to manage FCAS exposure, potentially increasing energy prices and reducing allocative efficiency. Origin submitted that concentrating contingency FCAS exposure could drive "providers to operate more conservatively to ensure sufficient capacity is available to manage their exposure", reducing available capacity for dispatch and contracting and placing upward pressure on prices.[61]

AEMO suggested that "where the marginal cost of FCAS exceeds the marginal energy profit of the largest dispatchable supply contingency, the benefit of its co-optimisation may be undermined by socialised allocation of FCAS costs". AEMO suggest that this is because the "largest dispatchable contingency is not exposed to the marginal cost of FCAS, but more likely a smaller cost after sharing with other suppliers". AEMO notes that the resulting behavioural incentive is for the spot trader to "defeat co-optimisation by offering an energy price lower than its own true marginal energy cost" and AEMO proposes that this issue could be addressed by a runway cost recovery approach.[62]

The Commission is satisfied with ACIL Allen's findings that co-optimisation is unlikely to result in inefficient bidding behaviour or materially affect participants' ability to manage commercial risk. ACIL Allen finds that co-optimisation is unlikely to cause any significant change in risk for participants, as generators can manage energy and FCAS dispatch outcomes through established bidding strategies.[63] Where FCAS prices are high, NEMDE may back off output from larger units to reduce FCAS requirements, but this outcome reflects efficient dispatch where the net reduction in FCAS costs outweighs any increase in energy costs. In such circumstances, generators retain the ability to rebid energy at or above their price of indifference, limiting adverse financial impacts.[64]ACIL Allen also found that these dynamics do not materially increase exposure under forward contracts, including in scenarios where energy and FCAS prices are simultaneously high, and that third-party intermediaries are expected to continue participating in contract markets.[65]

A number of stakeholders also expressed concern that co-optimisation could materially affect investment and contracting behaviour for large synchronous and dispatchable assets. Delta, Stanwell and EnergyAustralia submitted that increased curtailment risk and revenue volatility could weaken incentives to enter into long-term contracts, reduce derivative market liquidity, and undermine investment signals for assets that continue to play an important role in system reliability during the transition. For example, Delta cautioned that additional uncertainty "is likely to discourage long-term contracting and raise investment risk premiums, particularly for large-scale dispatchable assets that are critical to system reliability".[66]

The Commission agrees with ACIL Allen's finding that the co-optimisation of contingency FCAS requirements are not expected to materially change the level of contracts offered to the market. ACIL Allen's analysis indicates that electricity contracting behaviour is driven primarily by factors such as plant reliability, portfolio composition, network constraint risk, marginal costs, and participants' expectations of future spot prices, rather than by contingency FCAS procurement arrangements.[67] Accordingly, the Commission does not consider that co-optimisation would materially alter contracting volumes or undermine contract market liquidity.

61 Origin Energy, submission to the consultation paper, 18 December 2025, p.2.
62 AEMO, submission to the consultation paper, 18 December 2025. p.5.
63 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p. 31.
64 ACIL Allen, 2026, p.9.
65 ACIL Allen, 2026, p. 33.
66 Delta Electricity, submission to consultation paper, 18 December 2025, p.1.
67 Ibid.

Some stakeholders also questioned whether co-optimisation adequately captures interactions with broader system security services. EnergyAustralia, AGL and Stanwell submitted that co-optimising contingency size based on short-run cost considerations may undervalue the inertia, system strength and fault current contributions provided by large synchronous units, creating tension between short-run cost minimisation and secure operation. EnergyAustralia submitted that large synchronous units "provide fault current, inertia, voltage stability, and grid-forming stability which arrest the severity of frequency deviations" and that these services "are not reflected in FCAS prices and are not valued in dispatch co-optimisation".[68]

The Commission considers that while co-optimisation may result in larger units reducing their output, the output size would not significantly reduce the units' provision of system security services such as inertia, system strength and fault current. The Commission agrees with ACIL Allen's finding that contract positions and energy prices are more likely to impact a generator's commitment decisions, and as noted above, ACIL Allen does not consider co-optimisation of the largest credible contingency to have a significant impact on the ability for generators to hedge their risks through contract positions.

3.2.4 Improved transparency could minimise volatility risk and provide for improvements to co-optimisation practices over time

A consistent theme in stakeholder submissions and discussions at the TWG was that market participants currently find it difficult to observe and anticipate when co-optimisation of contingency FCAS requirements has been applied in dispatch outcomes. Stakeholders emphasised that reduced transparency can adversely affect the predictability of dispatch outcomes, confidence in price signals, and the ability to manage risk through bidding, hedging and contracting strategies.

The Commission considers that the core issue raised by stakeholders is one of visibility rather than outcomes. The Commission understands from its engagement with TWG participants that improved transparency and reporting around co-optimisation could be a key condition for being comfortable with its use, regardless of whether any formal expansion of co-optimisation were to be pursued. Improved transparency was viewed as a way to reduce perceived volatility risk and build confidence in market outcomes without constraining AEMO's operational discretion.

A targeted transparency approach is therefore intended to improve understanding without prescribing operational outcomes. Under the draft rule, AEMO would be required to provide clearer information on instances where co-optimisation has not been applied and the operational reasons for that decision. This would improve stakeholders' ability to interpret dispatch outcomes and price signals, while preserving AEMO's flexibility to respond to real-time system conditions, including uncertainty around non-enabled services and network-related contingencies.

This is consistent with the evidence base provided by ACIL Allen. ACIL Allen's analysis suggests that further benefits from broader application of co-optimisation may emerge as system conditions evolve. ACIL Allen noted that as the power system becomes more complex, with increased interconnection, greater penetration of variable renewable energy and reduced thermal dispatchable capacity, understanding scheduling and dispatch outcomes will require greater transparency.[69]In this context, less transparency around AEMO's decision-making — including reliance on non-enabled services — would hinder participants' ability to respond efficiently to price signals in both the short term and the long term. Requiring maximum transparency around

68 EnergyAustralia, submission to the consultation paper, 17 December 2025, p.3.

69 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p. 36-37.

AEMO's decision-making, scheduling and dispatch of services was described by ACIL Allen as a "no-regrets" policy that would improve allocative efficiency over time.[70]

3.3 The draft rule offers a proportionate response to the issues

The Commission's draft rule adopts a transparency-focused and proportionate approach that formalises AEMO's requirement to use reasonable endeavours co-optimise the largest credible contingency, enhances market transparency, and enables evidence-based improvement over time, without mandating operational change or imposing disproportionate costs and risks. The Commission considers that this approach best addresses stakeholder concerns identified through this rule change process while preserving continuity with the existing practice of co-optimisation of the largest credible contingency and consistency with existing market design principles. The core elements of the draft Rule are described in Box 4.

Box 4: Overview of the draft rule

The Commission's draft determination is to make a draft rule to clarify and improve transparency in relation to the application of co-optimising the largest credible contingency, including:

- formalising AEMO's use of co-optimisation through a new requirement for AEMO to use reasonable endeavours to co-optimise the largest credible contingency, consistent with its requirement to maximise the value of spot market trade under NER Clause 3.8.1(a) and 3.8.1(b).
- requiring AEMO to set out how it will perform co-optimisation of the largest credible contingency in the constraint formulation guidelines
- expanding AEMO's current ex-post reporting under the weekly and quarterly Frequency Performance and Time Deviation report to identify and comment on the application of co-optimisation over the reporting period.
- a transitional arrangement to undertake a review of the co-optimisation arrangements under the constraint formulation guidelines, following the first publication of weekly and quarterly reports under the draft rule.

The draft rule would:

- improve transparency and understanding of existing practices
- provide greater regulatory certainty around AEMO's discretion to undertake the practice of co-optimisation.

The Commission considers that introducing a rule mandating broader or routine application of co-optimisation in all circumstances would risk embedding complex operational judgements directly in the Rules, limiting flexibility and increasing regulatory risk. By contrast, a targeted, transparency-based approach provides a lower-risk and more proportionate response, enabling stakeholder understanding and constructive engagement without prescribing dispatch outcomes.

By improving clarity and visibility, the draft rule is expected to support continuous improvement in co-optimisation practices over time, without forcing immediate changes to dispatch outcomes or AEMO operations. Enhanced transparency will assist stakeholders to better understand the circumstances in which co-optimisation is applied and will support informed dialogue on whether,

70 Ibid.

and how, its application could be broadened as system conditions evolve, through existing consultation-based processes such as the network constraint formulation guideline framework.

The draft rule is not intended to mandate immediate implementation of co-optimisation through NEMDE, require changes to AEMO's current dispatch systems or constraint architecture, or specify particular mathematical formulations or operational thresholds. Decisions on when and how to apply co-optimisation remain matters of operational judgement for AEMO, allowing it to respond appropriately to prevailing system conditions, FCAS availability and security risks.

The Commission has considered stakeholder proposals to mandate broader co-optimisation and notes that such approaches would be likely to involve material implementation costs and delivery risks that would ultimately be borne by consumers and market participants. Given the modest and uneven benefits identified at this stage of the transition, the Commission considers it inappropriate to impose these costs.

The sections below discuss the draft R\rule and how it would operate.

3.3.1 The draft rule clarifies AEMO's requirement to undertake co-optimisation

The draft rule introduces two new provisions in clause 3.8.1 to formalise AEMO's requirement to co-optimise, while preserving flexibility to respond to implementation cost, risk and system security considerations. Importantly, the draft rule does not mandate changes to dispatch systems, NEMDE formulations, or constraint architectures, nor does it require co-optimisation to be implemented through any particular mechanism. The Commission considers this proportionate given the modest benefits identified and the potential costs and delivery risks associated with mandating broader co-optimisation.

This policy approach is consistent with ACIL Allen's advice, which indicates that while a rule change may not be strictly necessary to enable co-optimisation, formal clarification and increased transparency would provide benefits. ACIL Allen also observed that, in the absence of a clear rule framework, AEMO has not broadly adopted co-optimisation despite its technical availability, until recent updates to its constraint formulation guidelines following consultation in 2023.

New clause **3.8.1(b1)** provides that:

> *AEMO* must use reasonable endeavours to co-optimise the size of the largest *credible contingency event* in the *central dispatch* process in order to increase the value of *spot market* trading by reducing the cost of *market ancillary services*.

New clause 3.8.2(b2) provides that:

> *AEMO* must explain how it will perform co-optimisation under paragraph (b1) in the *network constraint* formulation guidelines issued under clause 3.8.10(c), including the co-optimisation process and methods that it will apply.

The draft rule under clause 3.8.1(b1) does not create an expectation that co-optimisation be applied routinely or in all circumstances. The reasonable endeavours obligation means that AEMO is only expected to apply co-optimisation where, in its operational judgement, doing so is appropriate and consistent with maximising the value of spot market trading. The Commission considers that in deciding on the circumstances where co-optimisation is appropriate, AEMO should give consideration to the materiality, practicality and system security implications which are currently part of AEMO's discretion and judgement when considering co-optimisation. Where AEMO considers that co-optimisation may not be appropriate, or is uncertain whether its

application would improve market outcomes, the Commission would not expect co-optimisation to be applied.

Decisions about whether and how to apply co-optimisation remain matters for AEMO's operational judgement, including consideration of system security outcomes and prevailing system conditions. However, the Commission recognises that transparency regarding this decision-making is important for market participants when interpreting dispatch outcomes.

The draft rule, under clause 3.8.1(b2) requires AEMO to provide guidance to participants on the circumstances in which it performs co-optimisation. The Commission considers that the draft rule establishes a process that is consistent with AEMO's established practice of documenting operational methodologies within the constraint formulation guidelines framework, while strengthening transparency and consultation opportunities.

The Commission recognises that while the constraint formulation guidelines is focused on documenting the application of network constraints, clause 3.8.10(c) establishes a minimum reporting and consultation requirement that may be expanded to include consideration of other constraint formulation considerations. This is consistent with current practice, whereby AEMO discusses FCAS constraints and its use of co-optimisation of the largest credible contingency in the constraint formulation guidelines, despite no explicit requirement under clause 3.8.10. The draft rule includes a note after clause 3.8.10(c) to signpost the requirement under clause 3.8.1(b2) for AEMO to explain how it will perform co-optimisation in the constraint formulation guidelines. This provides clarity for stakeholders in the NER.

The Commission recognises the importance of stakeholders' contributions to support the development of co-optimisation practices over time. Clause 3.8.10(c) requires that updates to the constraint formulation guidelines are consulted on under a Rules consultation process. This requires AEMO to seek stakeholder feedback through the publication of a consultation paper and draft report. The Commission considers this requirement would support AEMO in studying edge cases over time, enabling continuous improvement to such practices.

The Commission also considers that the draft rule is consistent with the market design principles under clauses 3.1.4(a)(1) and 3.1.4(a)(2) of the NER, which emphasise minimising AEMO decision-making in favour of participant autonomy, and maximising transparency to support efficient market outcomes.

> (1) minimisation of *AEMO* decision-making to allow *Market Participants* the greatest amount of commercial freedom to decide how they will operate in the *market*;
>
> (2) maximum level of *market* transparency in the interests of achieving a very high degree of *market* efficiency, including by providing accurate, reliable and timely forecast information to *Market Participants*, in order to allow for responses that reflect underlying conditions of *supply* and demand;

The timing implications of the draft rule are discussed in section 3.3.4, below.

3.3.2 The draft rule improves transparency of the application of co-optimisation

As noted in section 3.2, stakeholders have raised concerns about the difficulty of observing when co-optimisation is applied in dispatch and understanding why it is not applied in other instances. The Commission considers these concerns primarily relate to visibility, rather than to the outcomes of co-optimisation itself, and that targeted transparency measures are an appropriate and proportionate response.

The draft rule introduces new reporting requirements under clause **4.8.16** to improve visibility of AEMO's application of co-optimisation, without constraining operational decision-making:

- new clause **4.8.16(a)(4)** requires AEMO to include, in its weekly frequency performance report, information on the instances in which co-optimisation was applied during the reporting period, by market ancillary service type. This will provide participants with timely, high-level information on the use of co-optimisation in dispatch.
- new clause **4.8.16(b)(6)** requires AEMO to include, in its quarterly frequency performance report, where applicable, AEMO's assessment of the impact of co-optimisation in maximising the value of spot market trade.

Together, these reporting requirements are expected to support a more comprehensive understanding of how co-optimisation affects contingency FCAS procurement outcomes, and enable continuous improvement of this practice over time. The Commission considers that targeted reporting addresses stakeholder concerns directly by requiring AEMO to acknowledge when co-optimisation has been applied, and to provide high-level explanatory material on its impacts, without hard-coding prescriptive obligations into the Rules.

In practice, these reports would expand the *Frequency Performance and Time Deviation* reports published by AEMO on a weekly and quarterly basis to include reporting on co-optimisation practices. The Commission acknowledges that frequency performance reports have historically focused on system security outcomes. However, while the Commission considers that co-optimisation generally improves the system's economics, leveraging this existing and familiar reporting framework is an efficient and proportionate way to enhance transparency while avoiding duplicative reporting obligations. The Commission welcomes stakeholder feedback on the appropriateness of the proposed reporting mechanism.

The Commission is seeking stakeholder feedback on weekly reporting requirements

The intent of the weekly reporting is to provide participants with sufficiently granular information to understand when co-optimisation is applied in dispatch and to allow stakeholders to assess whether its application could reasonably be expanded over time. The Commission recognises that a weekly reporting frequency should not require AEMO to undertake extensive analysis. Rather, the focus should be on quantitatively identifying instances in which co-optimisation has been applied. On the other hand, the quarterly reporting seeks a qualitative assessment from AEMO on its application of co-optimsiation over the reporting period, and to provide a view to the market on whether the practice of co-optimisation could be expanded.

In developing this approach, the Commission seeks to strike an appropriate balance between providing information that is valuable to participants operating under co-optimised conditions and supporting potential enhancements to co-optimisation practices, while maintaining reporting simplicity through largely automated disclosure of co-optimisation constraint utilisation.

The Commission notes that generic constraint sets are published in MMS data on the following day. However, stakeholders have indicated that identifying when co-optimisation related constraints are applied remains challenging in practice, particularly without a clear explanation of the relevant constraint formulations. The Commission considers that improved visibility in this area would materially assist participants in interpreting dispatch outcomes.

To this end, the Commission envisages that weekly reporting would include information on:

- the dispatch intervals in which constraint sets relating to co-optimisation were applied to NEMDE

- application of any variation to these constraint sets (e.g. through swamping)
- the number of constraints that were binding in each relevant interval
- and the nature of the impact of binding co-optimisation constraints on the value of spot market trade.

and that AEMO's quarterly report include:

- indicative impacts on FCAS procurement outcomes (e.g. contingency volumes procured relative to typical levels)
- cumulative use of co-optimisation over the financial year
- commentary on whether co-optimisation could be applied more broadly (including relevant operational/security considerations).

The Commission considers that providing this information would deliver meaningful transparency benefits to participants, while avoiding the imposition of extensive analytical requirements at a weekly reporting frequency.

The Commission is seeking further stakeholder feedback on the specific information that would be most useful to include in the proposed weekly and quarterly reporting. In particular, the Commission will consider the extent to which the proposed combination of quantitative weekly reporting and qualitative quarterly assessment would provide sufficient transparency to identify when co-optimisation has been applied, interpret its impact on dispatch and prices, and support an assessment of whether its application could be expanded, while remaining operationally feasible and avoiding unnecessary complexity for AEMO.

The Commission does not consider that additional reporting requirements are required in relation to primary frequency response

As discussed in section 3.2.1,ACIL Allen observed that under current arrangements AEMO may rely on non-enabled frequency services when managing contingency FCAS requirements, with primary frequency response (PFR) being the predominant source of these services. ACIL Allen noted that there is limited transparency regarding AEMO's estimates of the volume of non-enabled services available at any point in time and that, as the power system transitions, the gap covered by non-enabled services may increase.

The Commission has previously considered transparency and visibility of PFR through its assessment of the mandatory primary frequency response rule change and subsequent reforms. Those reforms placed priority on improving AEMO's visibility of PFR capability and performance to support secure system operation. The Commission notes that PFR arrangements are generally bespoke and highly dependent on individual plant characteristics, operational settings and system conditions, which makes consistent and meaningful public reporting of non-enabled PFR particularly challenging.

The Commission considers that the existing regulatory framework governing PFR is operating as intended and that AEMO has sufficient mechanisms to manage and observe PFR outcomes for operational purposes. In light of this, and having regard to the implementation complexity and limited incremental benefit of additional reporting requirements, the Commission does not consider it necessary or proportionate to expand transparency or reporting obligations in relation to PFR at this time.

3.3.3 The draft rule introduces a transitional arrangement to consider updates to the constraint formulation guidelines

The draft rule introduces a transitional arrangement for AEMO to undertake a review of the co-optimisation arrangements under the constraint formulation guidelines, and commence this review process following the first publication of weekly and quarterly reports under the draft rule so that an updated version of the constraint formulation guidelines is published by 1 October 2028.

While the most recent publication of the constraint formulation guidelines (effective 2 December 2025) contains information on when generator output is currently co-optimised with FCAS requirements, the Commission considers that the guidance in relation to co-optimising the largest credible contingency should be reviewed in line with published information on co-optimisation practices.

The review could seek to expand the current guidance to provide the following information to market participants:

- the principles and methodology AEMO uses to determine whether co-optimisation is expected to increase the value of spot market trading
- the methodology used by AEMO in selecting how co-optimisation is implemented in dispatch, including how co-optimisation is reflected within constraint formulations or other operational mechanisms
- the process for applying, invoking, and discontinuing the use of co-optimisation under different system conditions
- where applicable, AEMO's approach to managing interactions between co-optimisation and any related operational outcomes, including the circumstances in which co-optimisation may be used to mitigate inefficient market outcomes while maintaining secure system operation.

The draft rule would also provide for the transitional arrangements to expire automatically on 31 January 2031. AEMO's review and update of the constraint formulation guidelines must be published by 1 October 2028 and the transitional provision will be redundant after that date. Removing redundant provisions ensures the rules are clearer to stakeholders and will improve the quality of the NER.

3.3.4 The Commission proposes a staged implementation approach to the draft rule

The Commission considers that a staged implementation approach to the draft rule is appropriate, having regard to AEMO's current implementation program, the priority of this rule change relative to other reforms, and the need to ensure continuity with AEMO's existing operational processes. The staged approach is intended to provide regulatory clarity in the near term, while allowing sufficient time for implementation of new transparency measures and for stakeholders to consider their implications.

From 4 September 2026, the draft rule would commence provisions clarifying AEMO's discretion to co-optimise the largest credible contingency. From this date:

- *AEMO* would be required to use reasonable endeavours to co-optimise the size of the largest *credible contingency event* in the *central dispatch* process in order to increase the value of *spot market* trading by reducing the cost of *market ancillary services*.
- *AEMO* would be required to explain how it will perform co-optimisation under paragraph (b1) in the *network constraint* formulation guidelines issued under clause 3.8.10(c), including the co-optimisation process and methods that it will apply.

The Commission considers that AEMO's existing practice of co-optimising under its current constraint formulation guidelines is broadly consistent with this requirement, and that these provisions largely clarify and formalise current arrangements rather than requiring material operational change.

From 1 October 2027, the transparency and reporting elements of the draft rule would commence. From this date:

- AEMO would publish, in its weekly frequency performance report, information on the instances in which co-optimisation was applied during the reporting period, by market ancillary service type.
- AEMO would publish in its quarterly frequency performance report, where applicable, AEMO's assessment of the impact of co-optimisation in maximising the value of spot market trade.

The Commission considers that this timing provides sufficient opportunity for AEMO to develop and automate the required reporting processes and aligns with the commencement of a quarterly reporting period. In effect, this provides AEMO with 13 months to implement the new reporting requirements.

By 1 October 2028, AEMO would be expected to complete a review of the network constraint formulation guidelines to consider the operation of co-optimisation in practice, taking into account any findings from the weekly and quarterly reporting publications. The Commission considers that this timeframe would allow participants and AEMO to review and assess the information made available through the new reporting arrangements and to propose potential refinements to co-optimisation practices through established consultation processes.

Overall, the staged implementation approach is intended to balance timely clarification and transparency with prudent delivery sequencing, enabling proportionate, evidence-based improvement of co-optimisation practices over time while managing implementation risk and cost.

4 The Commission makes a no-rule determination for cost recovery at this time

The Commission has decided not to make any change to the existing cost recovery arrangements. In addition to the runway cost recovery approach proposed by the proponent, the Commission has considered:

- A hybrid arrangement between the runway settlement approach and the current proportioning approach.
- Application of the frequency performance methodology to contingency FCAS arrangements
- Application of the deviation pricing philosophy to contingency FCAS arrangements methodology.

The Commission notes that while the current cost recovery arrangements may not be fully cost-reflective, they are well understood by participants. Further, the expected benefits of any change to contingency FCAS cost recovery arrangements at this stage are limited, and are unlikely to outweigh the material costs, complexity and delivery risks associated with implementation.

This chapter sets out the Commission's rationale for this decision.

4.1 The costs of implementing changes to cost recovery are high and are expected to outweigh the benefits

4.1.1 The current framework is imperfect but broadly fit for purpose

Under current arrangements, the volume of contingency FCAS procured by AEMO is principally determined by the size of the single largest credible contingency. The costs for the procurement of this FCAS are allocated to generators and loads for raise and lower services respectively in proportion to their total energy generated or consumed.

Contingency FCAS cost recovery arrangements are designed around a 'causer pays' principle. This is based on the idea that generation or consumption capacity should broadly correlate with the volume of energy generated or consumed, and so larger capacity generators and loads, which are more likely to set the contingency requirement, will face a greater share of the costs.[71]

The Commission recognises that current cost recovery arrangements are not fully cost-reflective. This is because contingency FCAS costs are not recovered by participants' incremental contribution to the contingency requirement, meaning that smaller units that do not influence the contingency requirement, pay the same rate per MWh for contingency FCAS as large units that set the requirement. In this sense, the current proportional arrangement is only loosely cost-reflective.

Despite this limitation, the Commission considers that current arrangements are simple, transparent, and operationally robust, and therefore largely fit-for-purpose. The framework is well understood by market participants, produces predictable dispatch and settlement outcomes, and avoids the need to introduce more complex allocation mechanisms that could be difficult to implement and sequence alongside competing market reforms.

Importantly, the Commission considers that these characteristics support relatively stable and efficient market operation. In this context, the Commission considers that the benefits of adopting an alternative approach would need to be significant and easily demonstrable to justify departing

71 NEMMCO, 2007. FCAS Review Final Report. p.26-27.

from the current framework. In the absence of such a case, the Commission is of the view that while imperfect, current arrangements are broadly fit for purpose.

The Commission notes that current arrangements also align with the market design principles set out under NER clause 3.1.4(a)(8), which states that:

> where arrangements require participants to pay a proportion of *AEMO* costs for *ancillary services*, charges should where possible be allocated to provide incentives to lower overall costs of the *NEM*. Costs unable to be reasonably allocated this way should be apportioned as broadly as possible whilst minimising distortions to production, consumption and investment decisions;

In assessing the need for further reform, the Commission has considered a range of alternative cost recovery arrangements to consider whether contingency FCAS costs could be apportioned to materially lower overall costs of the NEM.

The following sub-sections discuss the Commission's consideration of the application of the runway cost recovery arrangement as proposed by the proponent.

The Commission's consideration of alternative arrangements is considered in section 4.2.

4.1.2 The runway cost recovery arrangement may create inefficient incentives if applied broadly across participants

The proponent states that fairness and market efficiency could be improved by making contingency FCAS cost allocation more cost-reflective through the application of runway cost recovery. Under a runway cost recovery arrangement, contingency FCAS costs are allocated to participants based on their contribution to the size of the largest credible contingency. This results in larger generators, who drive the contingency requirement, bearing a greater share of costs, while smaller generators, who do not typically affect the requirement, bear a relatively smaller share.[72] The proponent considers that full runway cost recovery would be more cost-reflective because it would directly link the allocation of contingency FCAS costs to participants' incremental contributions to the contingency requirement.

The Commission agrees with the proponent that, in theory, runway cost recovery may improve cost-reflectivity and, in some cases, deliver efficiency benefits. By more directly linking cost allocation to participants' marginal contribution to the largest credible contingency, runway cost recovery allocates risk to the parties best positioned to manage it, namely, large generators who determine the contingency requirement. This creates an incentive for large generators to factor the contingency FCAS cost impact of their output into their energy offers and operational decisions.

In the short term, runway cost recovery may encourage large generators to make operational decisions that result in reduced output. In the longer term, it may influence investment decisions by encouraging plant configurations or operating profiles that reduce contribution to the largest credible contingency. To the extent that these responses reduce the contingency requirement, runway cost recovery may place downward pressure on contingency FCAS costs and improve market efficiency.

Notwithstanding these potential benefits, the Commission considers that runway cost recovery is likely to create inefficient incentives for generators who are not the largest credible contingency. Since cost allocation is based on each participants' contribution to a fixed contingency

72 For further information on how the runway approach works, refer to section 3.1.2 of the consultation paper.

requirement, generators who are not the largest credible contingency face a financial incentive to reduce output in order to lower their cost exposure and avoid moving up the runway. ACIL Allen noted that "during periods when FCAS prices are high, the second-largest generator(s) would face high costs, likely leading them to back off generation, but this would have no impact on the contingency FCAS requirement."[73]

This incentive for the non-largest credible contingency generators to reduce output is likely to be strongest during periods of tight supply or elevated FCAS prices, where generators achieve greater savings by bidding in ways that reduce their cost exposure, at a time where available capacity is most critical.

The incentive for generators who are not the largest credible contingency to reduce output is inefficient because reductions in output from these participants do not reduce the overall contingency requirement or the volume of FCAS procured. Rather, for these participants, runway cost recovery is more likely to result in a redistribution of costs among remaining participants rather than delivering material savings or enduring efficiency gains for consumers.

Further, the application of a runway cost recovery arrangement to large loads may create incentives for these participants to absorb large costs in the short to medium term. Unlike generating units, large loads are not as price responsive, and decisions to curtail energy consumption are likely to be driven by decisions tied to their line of business rather than changes in energy prices. This concern was highlighted by BlueScope and Viotas, with BlueScope emphasising that "the application of runway pricing to large industrial loads...may increase cost volatility and financial exposure for industrial users".[74] [75] BlueScope also notes that "these concerns arise from the operational realities of large, continuous industrial processes, which differ fundamentally from flexible generation or storage assets and cannot respond to FCAS price signals in real time"[76]

4.1.3 The costs, risks and complexity associated with implementing alternative cost recovery arrangements are significant

The Commission considers that there are material costs and risks associated with implementing any changes to cost recovery arrangements. Changes to cost recovery arrangements, whether to a runway approach or any alternative explored in this paper, would require non-trivial modifications to dispatch and settlement systems, which cannot occur in isolation. As noted by ACIL Allen, cost recovery mechanics are closely linked to how contingency requirements are determined in dispatch.[77]

This interdependence increases the scope of implementation and the risk of delivery and operational challenges, given that reform would require coordinated upgrades and monitoring across dispatch, settlement and assurance systems.

While the Commission has not sought formal implementation advice from AEMO, it understands that implementation costs associated with changes to settlement arrangements are likely to be comparable to the recent Frequency Performance Payments (FPPs) reforms in regulation FCAS

73 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p. 9
74 BlueScope, submission to the consultation paper. 18 December 2025. p.1.
75 Viotas, submission to the consultation paper. 18 December 2025. p2.
76 BlueScope, submission to the consultation paper. 18 December 2025. p.1.
77 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p. 8.

markets in 2025. At the time, AEMO advised that the cost of implementing a new causer pays arrangement to be in the order of $9.6 million.[78] The Commission considers that these costs may be reduced by AEMO's familiarity with implementation, however note that AEMO would need to still carry out supporting analysis, testing and verification to maintain settlement accuracy and system integrity. To this end, the Commission estimates that even under a conservative estimate, implementation costs would still be in the order of $2-3 million.

The Commission also considers that changes to cost recovery arrangements would need to be sequenced within AEMO's broader market reform catalogue, which currently extends to 2027, and includes other reforms with more immediate implementation priority.[79] The importance of introducing runway cost recovery therefore needs to be weighed against AEMO's delivery capacity, existing reform commitments, and the risk of diverting resources from higher-priority market reforms.

4.1.4 Expected benefits of changes to cost recovery arrangements are narrow, largely indirect and challenging to estimate accurately

The Commission considers that the expected benefits of changes to the cost recovery arrangements, whether to a runway approach or any alternative explored in this paper, are limited, largely indirect and challenging to estimate accurately. Changes to cost recovery arrangements, including the runway approach and alternatives explored in this paper, are likely to result in a redistribution of costs amongst participants, rather than a reduction in total costs.

While the Commission notes calls from some stakeholders for a robust assessment of the costs and benefits to justify further reform, the Commission has not undertaken an extensive quantitative assessment of the potential benefits of runway cost recovery or alternative cost recovery arrangements. This is because any such assessment would be driven by several assumptions in relation to the impact of a redistribution of costs amongst participants and the indirect impact of any cost savings by specific units as a result of the change, to energy consumers.

Consistent with this, ACIL Allen did not undertake historical counterfactual modelling of alternative cost recovery approaches either alone or with co-optimisation, noting that it was not possible to accurately determine how affected participants would have adjusted their bids under alternative approaches.[80]

Even if such behavioural responses were realised, the Commission notes that the frequency of benefits is constrained by the way contingency requirements are determined. While more cost-reflective approaches - such as runway cost recovery - may create incentives for generators to reduce the LCC, these incentives are likely to be strongest when contingency FCAS prices are elevated. Under typical market conditions, price signals may not be strong enough to consistently and materially affect the output of the unit setting the LCC, meaning benefits would be concentrated in a limited number of high-price intervals rather than realised consistently over time.

There is also uncertainty as to whether any efficiency gains from runway cost recovery would ultimately flow through to consumers. To the extent runway cost recovery primarily redistributes costs between participants, any private benefits may be retained by generators rather than passed through in the form of lower wholesale prices or reduced costs for consumers.

78 AEMC, Primary frequency response incentive arrangements, Rule determination, 8 September 2022. p.22.

79 AEMO NEM implementation road map, version 6.

80 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p. 11.

These limitations are compounded by the narrow cost base to which any benefits would apply. Contingency FCAS costs represent only 1–2% of quarterly total market turnover, meaning that even sizeable efficiency gains would have only a limited impact when considered holistically.[81]

Viewing these limitations together, the Commission does not consider that the expected benefits of runway cost recovery are sufficiently material, enduring or certain to outweigh the costs, risks and complexity of implementation.

4.2 In addition to runway cost recovery the Commission also assessed alternative cost recovery approaches but found that none justify reform

While the Commission considers there are material limitations in pursuing a runway cost recovery approach when broadly applied to participants, the Commission has also given consideration to the following alternative settlement arrangements, which are considered in the sub-sections below:

- Section 4.2.1**: Allocating a greater proportion of costs to the largest units only,** for example, using runway pricing only for the unit or units that set the largest credible contingency, or allocating costs based on shadow prices.
- Section 4.2.2**: Applying frequency performance payments,** under which cost allocation would be linked to participants' historical performance in responding to frequency deviations, measured through 'contribution factors'.
- Section 4.2.3**: Applying deviation pricing,** under which, costs would be allocated according to participants' real-time relative helpfulness or unhelpfulness in responding to frequency disturbances.

However, as noted in section 4.1, the Commission does not consider any of the alternative arrangements to materially improve upon the existing settlement arrangements.

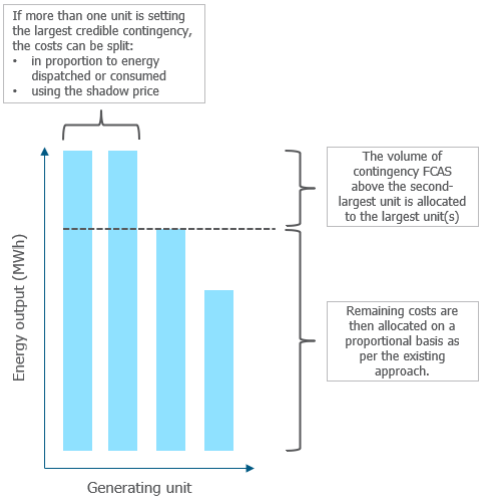
4.2.1 Approaches that allocate a greater share of costs only to the largest units may reduce distortions, but do not justify reform

The Commission considered a modified version of the runway cost recovery approaches that allocates a greater proportion of contingency FCAS costs to larger generating units, without adopting a runway cost recovery model that applies universally.

This approach allocates the marginal component of contingency FCAS costs only to the large unit or units setting the requirement, while recovering residual costs on a proportional basis. In principle, these approaches may improve cost-reflectivity while limiting some of the incentive and risk effects associated with full runway pricing, as discussed in section 4.1

81 AEMC, Contingency FCAS rule changes consultation paper, 20 November 2025, p.3.

Figure 4.1: Allocating a greater share of costs to only the largest units



Source: AEMC.

Note: The diagram above illustrates a two-step allocation of contingency FCAS costs where multiple generating units contribute to the largest credible contingency. First, the incremental contingency requirement, defined as the volume above the second-largest unit, is attributed only to the largest unit(s), reflecting their role in causing the marginal increase in the requirement. Second, remaining costs are allocated across participants on a proportional basis, consistent with the existing framework. Where more than one unit contributes to setting the LCC, costs between these units can be apportioned based on relative output, or shadow prices generated in dispatch optimisation.

The Commission considered two principal approaches to allocating a greater share of costs to the largest units as set out in Box 5.

Box 5: Approaches to allocate contingency FCAS costs to units impacting the contingency size

Allocating costs based on shadow prices

This approach allocates contingency FCAS costs using the shadow prices, or marginal values, of dispatch constraints. These prices are derived through the dispatch optimisation process and reflect the marginal change in total system cost associated with relaxing the contingency requirement. In this way, shadow prices provide a measure of the extent to which participants contribute to the marginal cost of increasing the contingency requirement in a given dispatch interval.

In practice, allocating costs on this basis means costs are borne by the unit(s)setting the largest credible contingency, because these units determine the contingency requirement, and the marginal cost of meeting the requirement, as reflected by the shadow price.

Under this approach, participants who do not affect the largest credible contingency would not face contingency FCAS costs. This provides a targeted cost-allocation model that reflects the largest units' discrete and marginal contribution to the contingency requirement.

Runway cost recovery for the largest unit(s) only

This hybrid mechanism uses runway cost recovery only for the incremental contingency FCAS costs associated with increases in the largest credible contingency. Remaining costs are then recovered from participants proportionally, as per current arrangements.

This approach may improve cost-reflectivity, as per full runway cost recovery, while mitigating some of the inefficient redistributive and behavioural effects discussed in Section. 1.1.

The Commission recognises that targeted applications of shadow pricing or runway cost recovery could sharpen incentives without incentivising inefficient behaviour from generators that are not the largest credible contingency. As these generators no longer pay in proportion to their contribution to the largest credible contingency, the financial incentive to lower output to reduce cost exposure and the perverse market outcomes it produces are largely mitigated. Ultimately, however, the Commission considers that these approaches would not offer benefits that are proportionate to implementation risks and complexity.

ACIL Allen notes that a drawback of the shadow pricing approach is that there can be multiple equally valid solutions of the shadow prices associated with contingency constraints in dispatch optimisation.[82] Therefore, cost allocation may depend arbitrarily on which of these valid solutions is selected, rather than reflecting a unique or stable measure of cost causation. While methods may exist to reduce or mitigate this issue, the Commission considers that introducing them would add unwarranted complexity and uncertainty to the cost recovery framework.

Therefore, the Commission considers that approaches that allocate a greater share of FCAS costs only to the largest units are unsuitable for reform at this time.

4.2.2 Frequency performance payments are an unsuitable mechanism for allocating contingency FCAS costs

The Commission considered whether contingency FCAS costs could be allocated using an approach based on FPPs. Under this approach, cost allocation would be linked to participants' historical performance in responding to frequency deviations. Participants who have historically contributed to maintaining system frequency would face lower cost allocation, while those who contribute negatively would bear a greater share of costs. This framework is currently used to recover costs in regulation FCAS markets, where 'contribution factors' are recorded by AEMO to reflect participant performance over time.[83]

The Commission recognises this approach has some potential advantages. In particular, it may strengthen participants' incentives to respond to frequency deviations, thereby improving overall system performance. It also leverages an existing framework, which may reduce implementation complexity relative to entirely new cost allocation mechanisms.

However, the Commission also considers that there is a fundamental misalignment between the drivers of contingency FCAS requirements and the basis for this cost-allocation method, rendering it an untenable solution. In particular, contingency FCAS is procured to manage discrete, low-probability, high-impact events, such as the loss of the largest credible contingency, rather than for ongoing frequency performance management. By contrast, frequency performance payments are designed to reflect participants' behaviour in normal operating conditions.

This means that there is only a weak causal relationship between a participant's measured frequency performance and the need to procure contingency FCAS. Participants with strong frequency response may still contribute to large contingency risks, while participants with weak performance may not materially influence the size of the contingency requirement. This misalignment reduces the effectiveness of FPPs in achieving cost-reflectivity and risks weakening the link between cost allocation and cost causation. This is supported by ACIL Allen's commentary that "the amount of contingency FCAS required is unrelated to general frequency

82 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes,p.22

83 For further information, see: https://www.aemo.com.au/-/media/files/initiatives/frequency-performance-payments-project/frequency-performance-payments-fact-sheet—-overview-final-for-publication.pdf?rev=96246096a9bf41e88b5d67a2cbe432b3&sc_lang=en

performance and dispatch compliance" and that "the FPP arrangement is "an unsuitable basis for the cost recovery of contingency FCAS".[84]

4.2.3 Deviation pricing is not appropriate for contingency FCAS cost recovery

The Commission considered the application of deviation pricing to contingency FCAS cost recovery. Under a deviation pricing approach, participants would be rewarded or penalised based on their contribution to frequency deviations following a contingency event, with payments linked to real-time system performance. Participants who respond in ways that help arrest or recover frequency would receive payments, while those who are unhelpful in the frequency response sequence would incur costs. This approach is intended to align incentives more closely with actual system outcomes by linking payments to real-time performance during contingency events.

The Commission considers that deviation pricing is not well-suited to contingency FCAS for several reasons:

- **Contingency events are infrequent and unpredictable by nature.** As a result, the revenue and cost streams associated with deviation pricing would be highly volatile and uncertain. This creates challenges for participants in forecasting costs and managing risk, and may undermine efficient investment and contracting decisions.
- **Deviation pricing interacts with the fundamental nature of contingency FCAS as a reliability service**. The purpose of contingency FCAS is to ensure that sufficient reserves are available ex-ante to manage a potential event. A mechanism that relies on ex-post performance signals may not provide a reliable basis for ensuring that sufficient capacity is procured ahead of time.
- **Deviation pricing could create self-defeating incentives**. There is a risk that incentives created by deviation pricing could reduce the need for contingency FCAS by encouraging participants to respond more effectively to frequency deviations. While this may be desirable for regulation FCAS, where services are used continuously, it is less appropriate for contingency FCAS, where requirements are determined by the size of the largest credible contingency rather than participant behaviour in real time.

As such, the Commission does not consider deviation pricing to be an appropriate replacement mechanism for current arrangements.

Further information on the application of a deviation pricing approach to contingency FCAS arrangements is set out in the Commission's 2017 Frequency control frameworks review.[85]

4.3 The Commission's draft rule for co-optimisation could guide future consideration of cost-recovery arrangements over time

Like other energy markets, contingency FCAS markets are likely to evolve over time. In particular, changes in system conditions, including increased penetration of fast-responding technologies, ongoing changes to the generation mix, and evolving network constraints, may affect contingency requirements and participants' responsiveness to cost-reflective price signals. As these conditions develop, the limitations under the current arrangements may deepen, while the potential benefits of other cost recovery arrangements may become clearer and, if sufficiently material, warrant further consideration.

The Commission does not consider that changes to contingency FCAS cost recovery arrangements are appropriate at this time. As set out above, the expected benefits of reform are

84 ACIL Allen, Contingency co-optimisation and cost allocation: Analysis to support AEMC considerations of proposed rule changes, 21 May, 2026, p. 2.
85 AEMC, Frequency control frameworks review, Final report, 26 July 2018.p.105

uncertain and limited in scope and are unlikely to justify the material upfront costs, complexity and risks associated with implementation. However, the Commission considers that changes to contingency FCAS cost recovery arrangements in future may be justified if the benefits become clearer, or system conditions evolve such that the case for change can be demonstrated to promote the long-term interests of consumers.

The Commission considers that the co-optimisation draft rule provides a practical pathway for assessing contingency FCAS market arrangements over time. By clarifying AEMO's ability to undertake co-optimisation and improving transparency around when and how it is applied, the draft rule is expected to strengthen the evidence base on the interaction between dispatch outcomes, FCAS procurement and total system costs.

In particular, the Commission considers that the weekly and quarterly reporting requirements proposed under the draft rule would provide participants with adequate transparency on the impact of co-optimisation on total system costs over time. Assessing this information could, over time, inform participants' views on the potential costs and benefits in shifting settlement arrangements.

A Rule making process

A standard rule change request includes the following stages:

- a proponent submits a rule change request
- the Commission initiates the rule change process by publishing a consultation paper and seeking stakeholder feedback
- stakeholders lodge submissions on the consultation paper and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a draft determination and draft rule (if relevant)
  - stakeholders lodge submissions on the draft determination and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a final determination and final rule (if relevant).

You can find more information on the rule change process on our website.[86]

A.1 Grids Energy Pty Ltd proposed rules to require AEMO to co-optimise contingency size in dispatch and recover contingency FCAS costs through runway pricing

Grids Energy Pty Ltd proposed rules to require AEMO to co-optimise contingency size in dispatch (ERC059) and to recover FCAS contingency costs through a runway cost allocation approach (ERC0360).

Under **ERC0359 – Optimising contingency size in dispatch**, the proponent sought to require AEMO to co-optimise the size of the largest credible contingency with wholesale energy in dispatch. The proponent considered that, under current arrangements, contingency FCAS costs are not typically co-optimised with energy dispatch, which may result in market inefficiency, particularly when FCAS costs are high. The proponent considered that integrating contingency size into dispatch optimisation would enable more efficient trade-offs between energy and FCAS costs.

Under **ERC0360 - Allocating contingency FCAS costs,** the proponent sought to replace the current proportional allocation of contingency FCAS costs with a runway approach. This approach would allocate costs based on generators' incremental contribution to the contingency requirement, rather than broadly smearing costs across all generators. In doing so, the proponent considered that a runway approach would better align cost recovery with the underlying drivers of FCAS requirements and strengthen cost-reflectivity.

The rule change requests are directed at improving the efficiency of contingency FCAS arrangements by better aligning dispatch outcomes with FCAS requirements and strengthening the 'causer pays' arrangement within the contingency FCAS cost recovery framework. By co-optimising contingency size with energy dispatch and introducing runway cost recovery, the proposals aimed to reveal participants' marginal contribution to system requirements, sharpen operational incentives to reduce contingency size and overall FCAS costs, and promote more efficient dispatch and investment outcomes over time.

86 See our website for more information on the rule change process: https://www.aemc.gov.au/our-work/changing-energy-rules

A.2 The process to date

On 20 November 2025, the Commission published a notice advising of the initiation of the rule process and consultation in respect of the rule change requests submitted by Grids Energy Pty Ltd. This notice was published under section 95 of the National Electricity Law (NEL). A consultation paper identifying specific issues for consultation was also published. Submissions closed on 18 December 2025. The Commission received 17 submissions as part of the first round of consultation.

To further test the proposals and explore technical issues, the Commission held a TWG. The TWG was convened on 1 April 2026 and included presentations from AEMO and ACIL Allen, and provided stakeholders with an opportunity to engage on the detailed design, costs, and risks of the proposed reforms.

The Commission considered all issues raised by stakeholders in submissions and through the TWG process. Issues raised in submissions and in the TWG are discussed and responded to throughout this draft rule determination. A summary of other issues raised in submissions and the Commission's response to each issue is included in Chapters 2 and 3.

B Legal requirements to make a rule

This appendix sets out the relevant legal requirements under the NEL for the Commission to make a draft rule determination.

B.1 Draft rule determination and draft rule

In accordance with s.99 of the NEL, the Commission has made this draft rule determination for a more preferable draft electricity rule in relation to the proposals by Grids Energy Pty Ltd.

The Commission's reasons for making this draft rule determination are set out in Chapter 2.

A copy of the more preferable draft rule is attached to and published with this draft determination. Its key features are described in Chapter 3.

B.2 Power to make the rule

The Commission is satisfied that the more preferable draft rule falls within the subject matter about which the Commission may make rules.

The more preferable draft rule falls within s.34(1)(a)(ii) and (iii) of the NEL as it relates to:

- operation of the national electricity system for the purposes of the safety, reliability and security of that system
- activities of persons (including registered participants) participating in the national electricity market or involved in the operation of the national electricity system.

B.3 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the draft rule
- the rule change request
- submissions received during first round consultation
- stakeholder input received at the Technical Working Group convened on 1 April 2026
- inputs from ACIL Allen through its final report findings
- the Commission's analysis as to the ways in which the draft rule will or is likely to contribute to the achievement of the NEO

B.4 Civil penalty provisions and conduct provisions

The Commission cannot create new civil penalty provisions or conduct provisions. However, it may recommend to the energy ministers' that new or existing provisions of the NER be classified as civil penalty provisions or conduct provisions.

The more preferable draft rule does not amend any clauses that are currently classified as civil penalty provisions or conduct provisions under the National Electricity (South Australia) Regulations.

The Commission does not propose to recommend to Energy Ministers' that any of the amendments made by the more preferable draft rule be classified as civil penalty provisions or conduct provisions.

Abbreviations and defined terms

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery Energy Storage System
Commission	See AEMC
FCAS	Frequency control ancillary service
FPP	Frequency Performance Payments
LHS	Left Hand Side
MW	Mega Watt
MWh	Mega Watt Hour
NEMDE	National Electricity Market Dispatch Engine
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NERO	National Energy Retail Objective
NERR	National Energy Retail Rules
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NT Act	*National Electricity (Northern Territory) (National Uniform Legislation) Act 2015*
PFR	Primary frequency response
Proponent	The proponent of the rule change request
RHS	Right Hand Side
TWG	Technical Working Group
VRE	Variable renewable generation