Technical Working Group meeting – FCAS Rule changes

ERC0359 - Co-optimising contingency size in dispatch

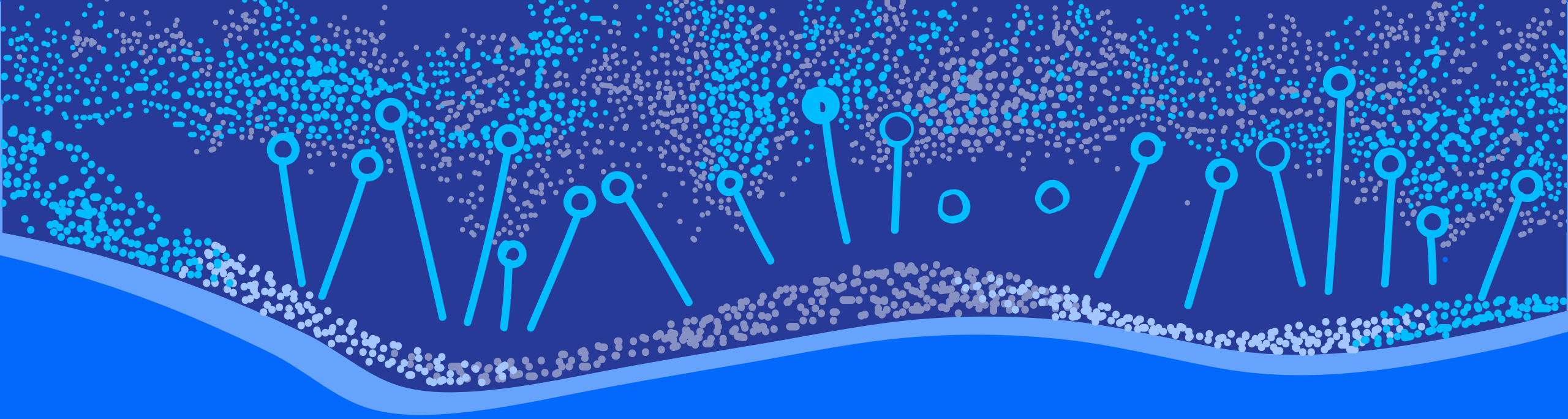
ERC0360 - Allocating contingency FCAS costs

This presentation represents the preliminary views of the AEMC project team and should not be taken to represent the views of the Commission.

1 April 2026

Australian Energy Market Commission

AEMC



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 the enduring connection of Aboriginal and Torres Strait Islander peoples to Country.

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COMPETITION PROTOCOL

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Introduction to the project team

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Agenda for today’s TWG meeting

1	Purpose of this TWG	~ 15 mins	Slides 8 - 9
2	Context and baseline	~ 20 mins	Slides 10 - 15
3	Co-optimisation	~ 90 mins	Slides 16 - 23
4	Cost recovery	~ 45 mins	Slides 24 - 32
5	WEM case study	~ 15 mins	Slides 33 - 36
6	Wrap up and next steps	~ 15 mins	Slides 37 - 38

Introduction

Today's objective

- We're grateful for your valuable and encouraging feedback on the AEMC's consult paper.
- Today we'll present our preliminary views on select priority issues and gather collective feedback.
- Your inputs will inform the Commission's draft determinations to be published on **4 June 2026**.
- ***Note:* These are staff-level views that have NOT been discussed with the Commission yet. The Commission has the final say in all decision-making.**

How this workshop will be run

- Please put your questions or comments into the **meeting chat box in Teams**.
- We'll moderate the Q&A and aim to respond to a couple of them live on each issue, if time permits. As part of this discussion we will be collecting responses via an online survey.
- We'll be publishing these slides after the workshop and accepting additional feedback until **10 April 2026**.

Purpose of the TWG

How we are collaborating with the Technical Working Group

The purpose of this TWG is to engage further with stakeholders on the costs and benefits associated with both rule change proposals. Please note this is a technical and economic testing forum, **not a decision-making forum**.

What success looks like - We are seeking strong and constructive engagement from a broad range of stakeholders on the presentation materials, specifically:

- clarity on the implementation implications of co-optimisation.
- well-evidenced view on principles and trade-offs in considering any revisions to the existing cost recovery approach.

Session roadmap

1 Context and baseline

- Background of the Rule change requests considered
- Overview of the frequency control reform program to date
- Overview of stakeholder feedback
- The assessment criteria in considering the proposals.

2 Co-optimisation discussion

- The current approach to determining the largest credible contingency (LCC)
- Specific stakeholder feedback related to the co-optimisation proposal
- **ACIL Allen:** Economic case for co-optimisation

Discussion: Understanding costs and risks of implementation

3 Cost allocation discussion

- The issues with the current approach
- Alternate cost recovery approaches considered
- **ACIL Allen:** The runway method and shadow pricing
- Application of a frequency performance payment approach

Discussion: Trade-offs for alternate cost allocation approaches.

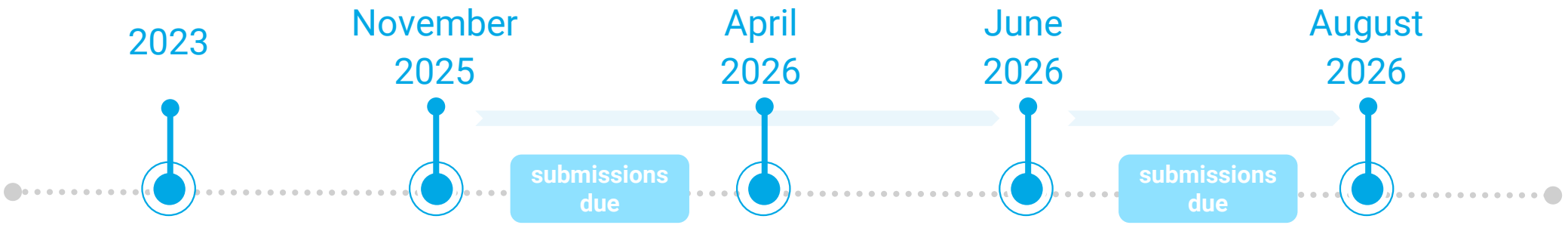
Context and baseline

The Commission published a consultation paper in November

This project relates to a package of rule changes submitted by Grids Energy Pty Ltd, which are focused on improving the contingency frequency control ancillary service (FCAS) arrangements in the National Electricity Market (NEM). The proposals include:

- **ERC0359 - Optimising contingency size in dispatch**: This proposal seeks to require AEMO to co-optimise the size of the largest credible contingency during dispatch.
- **ERC0360 - Allocating contingency FCAS costs**: This proposal recommends adopting a 'runway' cost allocation approach to recover contingency FCAS costs.

These Rule changes were received by the AEMC in April 2023 and commenced in November 2025, with the publication of a consultation paper. Over this period, the AEMC considered a range of reforms in relation to frequency control.

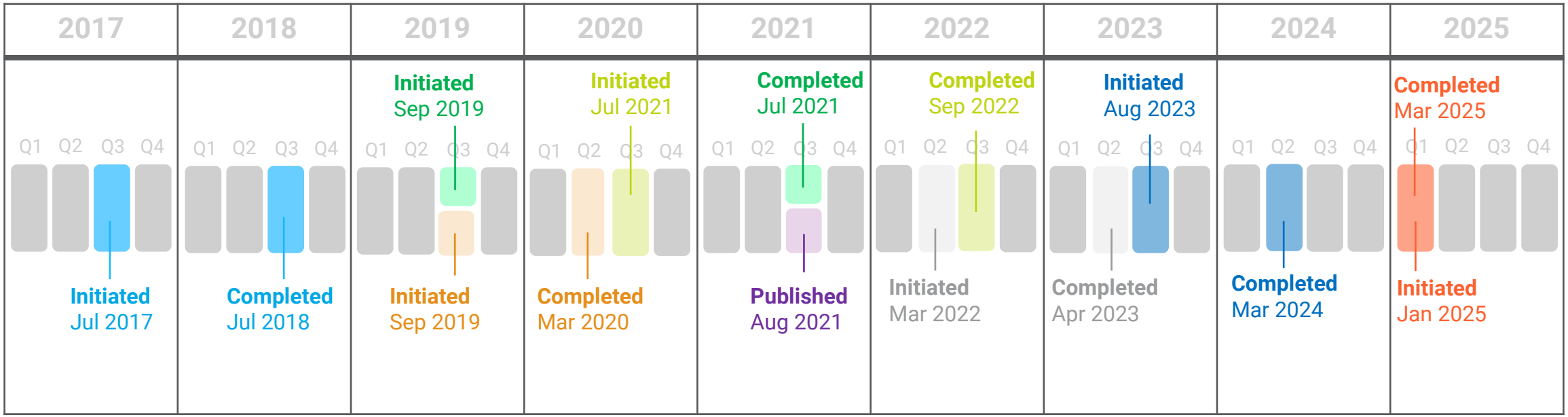


Milestone

Consultation period

There has been an active frequency control reform program

1. Frequency control frameworks review
2. Mandatory primary frequency response
3. Fast frequency response
4. PFR incentive arrangements
5. AEMO PFR technical white paper
6. Reliability Panel review of the FOS
7. Clarifying MPFR obligations for bi-directional units
8. Amendments to FPP cost recovery



1 Highlighted issues and proposed solutions to improve freq. control in the NEM.

2 Introduced the mandatory PFR obligation for scheduled and semi-scheduled generators.

3 Introduced two very fast FCAS services (1 sec raise and lower contingency FCAS).

4 Confirmed the mandatory PFR obligations and introduced frequency performance payments.

5 AEMO technical white paper supporting narrow band mandatory FPR as essential for maintaining frequency security.

6 The Reliability Panel confirmed the existing settings for normal operation and the primary frequency control band.

7 Clarifying the PFR obligations of bi-directional units when discharging, charging or enabled for FCAS.

8 Made minor changes to clarify cost recovery arrangements for frequency performance payments.

The proposals are being considered against three main criteria

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 National Electricity Objective (NEO). The Commission may make a rule that is different, including materially different, to a proposed rule if it is satisfied that the more preferable rule is likely to better contribute to the achievement of the NEO.

This TWG is designed to seek views on the merits of these proposals in the context of the **NEO assessment criteria**:

- safety, security and reliability
- principles of market efficiency
- implementation considerations

The Commission will consider stakeholder views in the context of the NEO to assess viable policy options for the draft determination – including making a Rule in line with the Rule change proposals, not making the proposed rule (a business-as-usual scenario) and making a more preferable rule.

Safety, security and reliability

The rule change requests relate to the way in which dispatch optimises the size of the largest credible contingency.

Principles of market efficiency

There may be market efficiency gains from optimising the amount of FCAS required and internalising costs, to improve price signals for operation and investment.

Implementation considerations

There are implementation considerations from the necessary changes in AEMO's systems as well as the potential impact on the pace of the transition.

Key themes emerging from stakeholder feedback to date

This slide captures the three high level themes from stakeholder feedback. More specific issues are captured later in the pack. **17 submissions** to the consultation paper were received. Stakeholders raised a range of objections to both proposals. Only two submissions were generally supportive of considering changes to the existing FCAS arrangements (Hydro Tasmania, Powerlink). AEMO was cautiously supportive of further investigation of some elements, while **all other submissions were generally not supportive**.

The current arrangements are generally effective

Stakeholders generally consider the existing FCAS arrangements fit for purpose, describing them as transparent and predictable, enabling participants to understand their likely exposure and manage risk in ways that minimise market distortions.

Do the efficiency gains justify the proposed changes?

Given the relatively small value of contingency FCAS costs and the additional dispatch complexity the changes would introduce, stakeholders questioned whether the efficiency gains justified the proposed changes.

The need for rigorous cost-benefit analysis

Stakeholders emphasised the need for rigorous cost–benefit analysis and detailed studies to demonstrate the value of the proposed changes, given the potential risks involved.

Please let us know if we have mischaracterised any stakeholder feedback throughout the pack.

AEMO: Response to consultation paper

FCAS/energy co-optimisation
AEMO submission

- Co-optimising large dispatchable energy quantities with FCAS contingency markets can be beneficial
  - In some cases will efficiently reduce size of the largest contingency
    - where reduction in FCAS marginal cost > increase in energy marginal cost
- Co-optimising is already used in some circumstances, but not universally
  - typically significant network outage conditions
- Rules adequate
  - 3.8.1 Maximise value of trade.
    - 3.8.10(c) Constraint Formulation Guidelines discuss co-optimising.
    - Routinely consulted – best place to raise missed co-optimisation opportunities
- There are many places where co-optimisation is not feasible or appropriate
  - 1 second FCAS non-linearities; aggregated stations; non-scheduled contingencies;
  - FCAS smeared recovery creates incentive for contingent units to bid away from cost

FCAS/runway settlement
AEMO submission

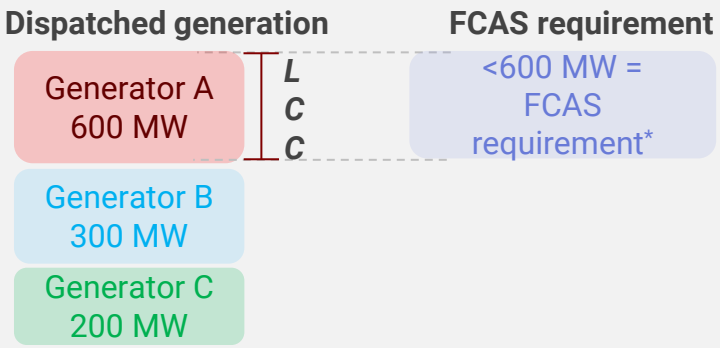
- AEMO accepts the existing recovery arrangement is imperfect “causer-pays”
  - Majority of FCAS contingency costs recovered from participants that don’t cause
  - During high FCAS prices, observe energy offers inefficiently increasing
  - Not worth co-optimising largest generator with smeared recovery
    - Largest generator would lower energy offer to defeat the optimisation
  - Network contingencies often biggest risk, resulting costs paid by market participants
- Runway settlement also imperfect
  - Correct on largest contingency, incorrect on second and third largest
    - Incentive on second largest to inefficiently *raise* energy offer
- Other solutions? Hybrids?
  - Can network contingency costs be recovered from the trading surpluses networks create?
- After finding a theoretically better approach, is a change worth it?
  - Batteries reducing FCAS costs, but data centres and REZs may counteract

Optimising contingency size in dispatch

Optimising contingency size can improve market efficiency

Contingency FCAS is procured to cover a trip of the LCC

Contingency FCAS is procured to recover frequency following the loss of the largest credible contingency (LCC), net of load and other frequency requirements. This is illustrated in the diagram below.



*In practice, the contingency FCAS requirement can vary slightly from the LCC dispatched. We will unpack later in this discussion.

Optimising contingency size can improve market efficiency

Optimising contingency size can improve market efficiency by requiring NEMDE to consider the total system cost of energy and FCAS by also optimising the FCAS requirement, rather than only considering the bids that minimise the cost to meet the requirement.

This is captured in the table below. Reducing the generation A output, results in a small increase to energy and a larger fall in FCAS costs, leading to an overall cost saving.

There is no explicit NER requirement to optimise contingency size

AEMO currently optimises contingency size in some intervals under its function to maximise the value of trade (NER clause 3.8.1 (b)).

To date this has typically undertaken during regional separation events, where there is a credible risk of separation or in periods of FCAS scarcity.

There is currently no explicit NER requirement for AEMO to optimise the size of the largest contingency.

	Current approach	Optimised
Gen A ($50/MWh)	600MW ($30,000/hr)	500MW ($25,000/hr)
Gen B ($60/MWh)	400MW ($24,000/hr)	500MW ($30,000/hr)
Energy cost	$54,000/hr	$55,000/hr
FCAS cost ($30/MWh)	$18,000/hr	$15,000/hr
Total cost	$72,000/hr	$70,000/hr
Net saving		**$2,000/hr**

Overview of the approach to considering stakeholder feedback

Theme	Stakeholder feedback	Approach to considering the feedback

Materiality of benefits	• Declining FCAS prices and AEMO's current process of co-optimisation may mean the benefits are not material enough to justify reform today.
	• However, changing system conditions (e.g. REZ developments and network contingencies) could make benefits more material over time.
		• The Commission has engaged ACIL Allen and SW Advisory to provide advice in relation to the materiality of benefits.
		• **ACIL's analysis shows there are material benefits in undertaking co-optimisation**. This analysis considered:
		  ○ the value of improvements to market efficiency from co-optimisation, now and into the future.
		  ○ the potential impacts on FCAS providers.
		ACIL's presentation will discuss this further.

Implementation feasibility	• It may be challenging to apply co-optimisation to all contingency FCAS markets, as:
	  ○ some FCAS relationships are non-linear, e.g. inertia, making NEMDE integration challenging
	  ○ there are limits for non-scheduled load
	• Changes to NEMDE can be complex and costly and would need to be considered in the context of other initiatives underway.
		• The **aim of this TWG discussion is to deepen our understanding of the potential costs and risks involved with expanding AEMO's current practice of co-optimsiation**. We consider that there are two aspects involved:
		  ○ AEMO's implementation costs
		  ○ risks and costs for impacted participants from potential changes
		• The Commission is working with AEMO to understand the implementation costs associated with this reform.
		• Therefore, **the focus of the discussion is to understand from the TWG the implications for FCAS providers in applying co-optimisation more extensively.**
		• See slides 21 to 23 for further details and questions for discussion.

Incentives and behavioural impacts	• There are risks of increased dispatch volatility and forecasting difficulty if the largest credible contingency (LCC) changes frequently. • Current socialised FCAS cost recovery may weaken incentives for co-optimisation, as the LCC does not face the marginal FCAS costs it drives.	

ACIL Allen: The Economic case for co-optimisation

Q&A time

Stakeholders highlighted specific challenges with co-optimisation

We are keen on understanding the potential for adverse bidding responses, and whether sufficient transparency would support unintended bidding outcomes. We are also interested in understanding from stakeholders whether there could be approaches that do not undermine the security services provided by large generating units.

Stakeholder concerns raised

- **Reduced transparency and predictability of dispatch** – Introducing economic optimisation of contingency size weakens the link between bids, dispatch and revenues, making outcomes harder to anticipate and explain (Delta, CS Energy, AGL, EnergyAustralia).
- **Investment and contracting risks for large assets** – Curtailment risk and increased revenue volatility may undermine long-term contracting, derivative market liquidity, and investment signals for large synchronous and dispatchable plant (Delta, CS Energy, AEC, ENGIE, Stanwell, EnergyAustralia).
- **Risk of inefficient behavioural responses** – Participants may rebid defensively, withhold capacity, or operate more conservatively to avoid FCAS exposure, potentially increasing energy prices and reducing allocative efficiency (Origin, Delta, Stanwell, EnergyAustralia).
- **System security interactions not fully captured** – Co-optimisation may undervalue inertia, system strength and fault current contributions from large synchronous units, creating tension between short-run cost minimisation and secure operation (EnergyAustralia, AGL, Stanwell).

What our preliminary, staff-level assessment indicates – for stakeholder feedback

- We recognise stakeholder concerns regarding potential impacts on transparency and predictability of dispatch. We are keen to test with the TWG how transparency could be maintained or improved under any co-optimised approach (see next slide).
- Our preliminary assessment, informed by ACIL Allen's analysis, indicates that co-optimisation is unlikely to have a material impact on contract market outcomes. In particular, the analysis did not identify significant adverse effects on contract market liquidity or participants' ability to hedge.

Questions for consideration

1. How are participants likely to adjust bidding, availability, or rebidding behaviour under co-optimisation? Could these responses impact expected FCAS cost savings?
2. If AEMO were provided with flexibility to not co-optimise, what are the circumstances under which AEMO should be provided this flexibility to address stakeholder concerns?
3. What are we missing?

Considering the need for improved transparency for co-optimisation

ACIL's analysis indicates there may be **economic efficiency benefits from broader application of co-optimisation**. AEMO has noted in its submission that there are limitations in the application of co-optimisation. From a stakeholder perspective, it can be difficult to observe or anticipate when co-optimisation is used in dispatch. We are exploring whether greater transparency could help stakeholders better understand dispatch outcomes and incentives, without constraining operational decision-making.

Potential options for consideration

Status quo

- Maintain current arrangements, relying on existing operational disclosures and engagement.

Targeted reporting by AEMO

- High-level reporting on instances where co-optimisation could or could not be applied.
- Potentially through an existing publication (e.g. the Quarterly Frequency Performance Report).

Process-based transparency

- Deeper stakeholder engagement through existing forums, such as the constraint formulation guidelines process.
- Clarifying how co-optimisation considerations are reflected in constraint design and application.

Questions for consideration

1. Is additional transparency around co-optimisation needed, or are current arrangements sufficient? If so, what information would be most useful to participants (and what would not)?
2. How frequently should transparency be provided to be meaningful without creating noise?
3. Where is the most appropriate place for AEMO to report on this need (reporting, guidelines, or engagement)?
4. How should transparency be balanced against system security and operational flexibility?

Implementation considerations

The AEMC is working closely with AEMO to understand the costs associated with implementing changes in NEMDE. We are interested in broadening our understanding of the costs to participants that arise from broadening application of co-optimisation.

Stakeholder concerns raised

- Changes to NEMDE and constraint formulation are non-trivial and costs and risks may outweigh limited benefits without strong safeguards and clear thresholds (CS Energy, AEC, Shell, Stanwell).
- 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, Powerlink, AEMO).

Questions for consideration

1. **To what extent does AEMO's current practice already deliver the benefits of co-optimisation?** What additional benefits (if any) could a rule-based approach unlock relative to the status quo?
2. **Where do you see the main implementation costs and risks falling?** E.g. AEMO systems and processes, FCAS providers, large generators, or the boarder market
3. **How feasible is it to apply co-optimisation consistently across contingency FCAS markets?** Are there specific service types or system conditions where risks or limitations are more pronounced?

Cost recovery

Current contingency FCAS cost recovery is loosely cost-reflective

The current approach – proportional cost recovery

- In the NEM, contingency FCAS costs are recovered from the participant class that sets the requirement, consistent with a broad 'causer pays' approach:
  - **Raise services:** cover generator trips and are recovered from generators in proportion to their share of dispatch
  - **Lower services:** cover load or network disturbances and are recovered from loads in proportion to their share of consumption
- Scheduled, semi-scheduled, and non-scheduled generators and loads can all provide contingency FCAS, but non-scheduled participants must first be registered as ancillary service units
- There are 8 contingency FCAS markets in total (raise & lower across 4 timeframes), each with a discrete role in the frequency recovery sequence
- We note that some timeframes overlap with the delivery and function of other system services. Notably, very fast (1 second) contingency FCAS considers system inertia, and Delayed (5 min) is partially substitutable with Regulation FCAS

Issues with the current approach

Loosely cost-reflective

- Proportional cost recovery is not cost-reflective because each participant's FCAS costs are not strongly correlated with their own contingency risk, but rather with the risk of the largest unit
- This can be seen in NER clauses 3.15.6A(f) & (g1), which provide for contingency raise and lower cost recovery for generators and loads respectively, based on their share of regional sent-out energy *(TSOE/RATSOE)* or consumed energy *(TCE/RATCE)*

Raise recovery formula

$$TA = RTCRSP \times \left(\frac{TSOE}{RATSOE}\right) \times -1$$

Lower recovery formula

$$TA = RTCLSP \times \left(\frac{TCE}{RATCE}\right) \times -1$$

Misaligned incentives

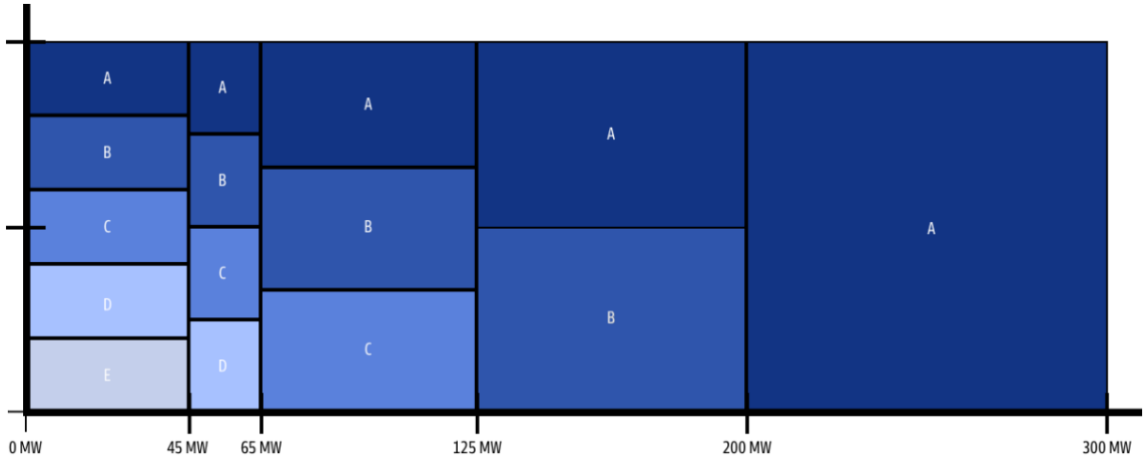
This cost recovery approach may create the following incentives:

- As large generators increase output, most FCAS costs are borne by other participants, meaning large units are not incentivised to reduce their size
- When contingency prices rise, small generators may curtail output to avoid socialised costs, withdrawing cheap capacity and pushing prices higher
- There are no incentives for large, new investment to consider the FCAS costs that it will impose on the system over its lifetime

Overview of the runway cost approach to contingency cost allocation

Proposed change – runway cost recovery

- **Grids Energy** proposed replacing proportional cost recovery with full runway cost recovery for contingency raise and lower services.
- Under runway cost recovery, larger generators and loads would bear the cost of the additional FCAS requirements they impose on the system through a 'runway cost factor'
- Grids Energy noted that this change would more accurately reflect the causer pays philosophy.
- The proportion of output that exceeds the next largest unit is borne exclusively by the largest generator, while common layers of risk are shared progressively among all generators.
- This is shown in the example on the right, where generator A is attributed the portion of costs above the second largest unit, generator B. Generator A then shares with generator B the portion of costs above the third largest unit, generator C, but less than generator B. This pattern repeats until all the generators are attributed a portion of the costs.



Generator	A	B	C	D	E
Output (MW)	300	200	125	65	45
Current cost factor (%)*	40.8	27.2	17	8.8	6.1
Runway cost factor (%)	57.2	23.8	11.3	4.7	3

Stakeholder feedback raised several concerns with runway pricing

Theme	Stakeholder feedback
Safety, security and reliability	• Runway pricing penalises large synchronous generators based on energy contribution, ignoring the inertia, fault current and system strength they provide — creating incentives to reduce availability of the units most critical to security. • If the largest unit trips, liability cascades instantly to the next largest, who may ramp down to avoid cost — potentially amplifying rather than containing a frequency disturbance.
Principles of market efficiency	• While the current socialised allocation distorts energy bids, contingency FCAS is only ~1-2% of wholesale costs and declining — the efficiency gain from reallocation appears marginal relative to the risks introduced • Runway pricing excludes network contingencies despite interconnector trips and potential future REZ failures being among the largest FCAS cost drivers, leaving the most material causes unaddressed • Concentrating unhedg`eable financial exposure on the largest unit would reduce willingness to offer firm financial contracts, undermining derivative market liquidity at a time the NEM Review has already identified this as a systemic risk
Implementation considerations	• Some stakeholders considered the definition of "large loads" remains unresolved — the distinction between flexible in-market loads (batteries, pumped hydro) and non-flexible industrial loads is consequential for cost allocation but not addressed in the proposal. • No quantitative cost-benefit modelling has been provided, and Shell Energy noted NEMMCO already rejected runway pricing in 2007 for lack of compelling net benefits — analysis that the consultation paper does not displace • Multiple stakeholders called for a Technical Working Group and additional consultation round before determination, with the March 2026 draft determination timeline widely viewed as insufficient

We have given consideration to other cost recovery approaches

In addition to the existing arrangements and runway pricing cost allocation approach, we have also considered other cost recovery approaches in our assessment including the shadow pricing approach and applications of the frequency performance payment methodology and deviation pricing approaches. Of course – another solution would be to make no changes to the current arrangements.

Shadow pricing

- The sets of constraints in the co-optimisation can be used to determine the shadow price for each FCAS service.
- Only the generators with total dispatch equal to the largest contingency will have non-zero shadow prices, as these services set the LCC requirement.
- The sum of these shadow prices equals the marginal cost of the contingency FCAS service.
- FCAS costs can then be proportioned based on the shadow price contribution of each unit in the respective dispatch interval.
- We considered a variation to this approach to apply thresholds for which shadow prices are applied.

ACIL presentation to discuss this further.

Application of frequency performance payments

- This approach expands on the current approach to allocating regulation FCAS costs.
- Contingency FCAS costs would be allocated based on the participants' previous performance in responding to frequency disturbances.
- Those that contribute positively to maintaining frequency within safe operating limits are rewarded with lower costs.
- Participants that do not contribute positively, or are not registered to provide contingency FCAS services may be attributed higher costs.

See slide 31 for further details.

Application of deviation pricing

- Under this approach, participants would be paid based on their contribution to arresting the frequency deviation following a contingency event.
- The Commission considered this approach as part of the 2017 Frequency control frameworks review, and considered that this mechanism is challenging to adopt as:
  - the income stream to participants would be less stable and more risky
  - by creating incentives to respond appropriately, there would be a reduction in the need for the service. This works for regulation FCAS, but not for contingency FCAS as these requirements are set by the LCC.
- As this approach considers both the procurement and payment of contingency services, we consider this approach is outside the scope of our rule change request.

ACIL Allen: Assessing the runway and shadow pricing method

Q&A time

Application of a frequency performance approach

This approach would allocate contingency FCAS costs to participants that are persistent causers of frequency or dispatch errors based on existing "default contribution factors" used for allocating regulation FCAS costs. The benefits of this proposal would be:

- incentivising market participation (improving dispatch compliance)
- recognising the value provided by scheduled generators and batteries that provide mandatory PFR – by allocating less contingency FCAS costs to these participants.

How it would work

- Through the Frequency performance payments (FPP) process, AEMO determine default frequency contribution factors based on the historic performance of all market participants that provide AEMO with SCADA data on active power.
- These default contribution factors depend on the participants' performance with respect to frequency and dispatch compliance, based on historical performance for the respective unit of generation or load.
- The costs of contingency FCAS would be allocated to market participants based on the negative default contribution factors.
- Under this approach, participants (including non-scheduled generation and load) with positive contribution factors would not be allocated any costs for contingency services. The costs for these services would be borne by participants with poor dispatch compliance and poor frequency responsiveness.

Benefits – (initial assessment for stakeholder feedback)

- This approach would incentivise visibility and participation in energy dispatch, through scheduled or voluntary scheduled resource classifications. This would align with the policy objectives for the *Integrating price-responsive resources rule* and Recommendation 2 from the National Electricity Market wholesale market settings review.
- The implementation of this proposal would be relatively straightforward, as it leverages the existing FPP processes.
- This approach would avoid allocation of contingency costs to participants that are frequency responsive, irrespective of FCAS enablement. This creates an additional incentive for capable units to respond to frequency and offer to provide FCAS.

Drawbacks - (initial assessment for stakeholder feedback)

- There is a weak causal link between unit default contribution factors and the need for contingency FCAS. The need for Contingency FCAS is triggered by the risk of rare, discrete events, which are not directly related to frequency performance and dispatch compliance.

Questions for the TWG to consider

Policy questions for TWG consideration

1. Do you consider there to be a material problem with the current contingency FCAS cost recovery framework, or is it broadly fit for purpose? If there is a problem, what is the primary issue that needs to be addressed? (e.g. cost reflectivity, incentives, equity, transparency, predictability).
2. Do you think there is a strong case for change to be made to the existing cost recovery framework?
3. Do you think that runway pricing would materially improve cost reflectivity relative to the current proportional approach?
4. What do you see as the most significant risks or drawbacks of runway pricing, if implemented in the NEM?
5. Would you be open to alternative approaches to runway pricing (e.g. shadow pricing or performance-based allocation)? If so, which appear most promising and why? If not, why not?
6. What additional benefits and drawbacks, if any, can you think of?

WEM case study

Case study: The WEM undertakes runway pricing and optimises the LCC

The Wholesale Energy Market (WEM) implemented both contingency size co-optimisation and the runway pricing cost allocation approach. The following slides discuss the rationale for introducing the arrangements.

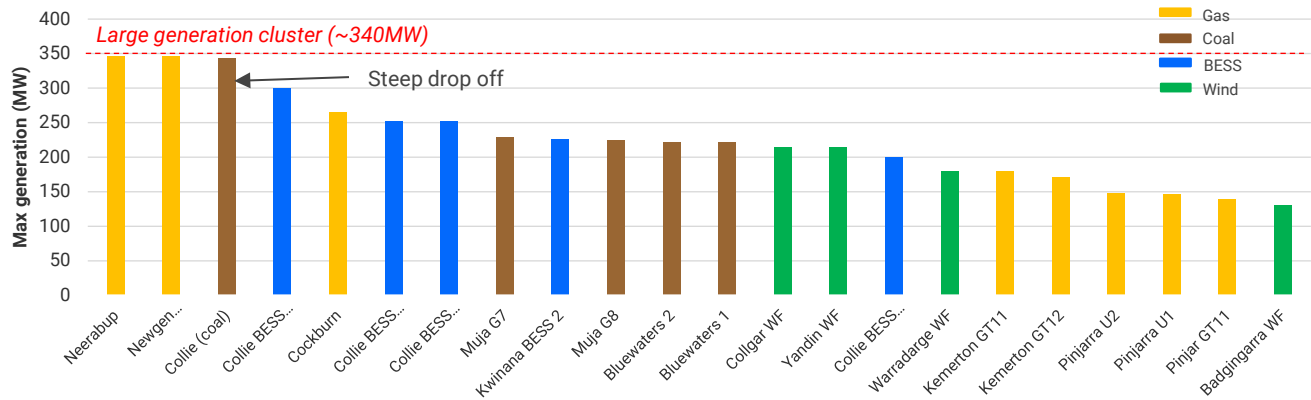
Overview of the WEM arrangements

- The WEMDE engine, co-optimises energy, contingency reserve raise (CRR), the size of the Largest Credible Supply Contingency (LCSC) and inertia via the RoCoF control service.
- When the system is insecure for the potential loss of the LCSC, WEMDE can either increase the CRR requirement or curtail the contributing facility — choosing whichever minimises total costs
- CRR costs are recovered through a causer pays runway model.
- Contingency sizes in WEMDE incorporate DPV shake-off (the volume of rooftop solar expected to trip following a network fault).

Suitability of optimisation and runway pricing in the WEM

- SWIS is an island system with no interconnection, making contingency size optimisation particularly valuable in the absence of external reserves.
- The WEM generation mix is highly concentrated, with a few large thermal units and a long tail of smaller plant.
- The LCSC is therefore often set by a small number of dominant facilities, making the “runway” analogy a useful way to frame cost allocation.
- The largest credible contingency is ~394 MW, driven by a non-redundant 330 kV connection linking Yandin (214 MW) and Warradarge (180 MW).
- Individual large units represent ~16.5% of average demand (~2.4 GW), creating a direct link between unit size and reserve costs.

The WEM generation mix comprises a large generation cluster and small market size



History of reform

Full runway pricing has been in the WEM since 2019, while contingency size optimisation was introduced in 2023.

Overview of the WEM arrangements

- **Prior to 2019**, spinning reserve costs were allocated via a modified version of runway pricing, based on 5 output blocks.

Block Number	Block Range (MW)	Block Size (MW)
1	> 200	100
2	>125 and ≤ 200	75
3	>65 and ≤ 125	60
4	>45 and ≤ 65	20
5	>10 and ≤ 45	35

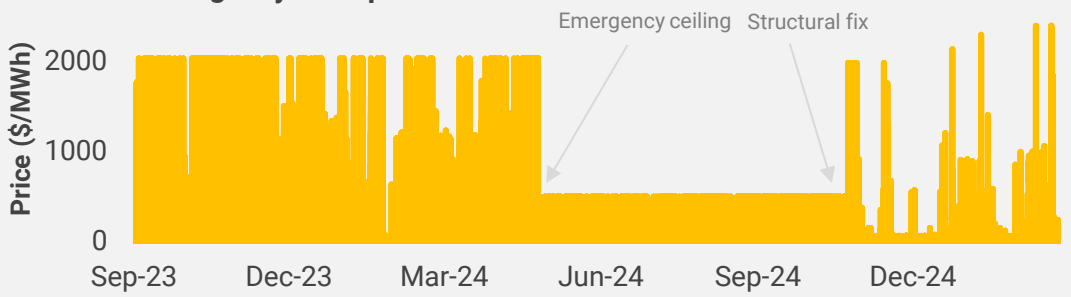
- The block thresholds incentivised generators to withhold capacity, pushing more expensive plant to dispatch, raising market costs. This led to a rule change request from WA's Public Utility Office in 2018.
- In 2019, full runway pricing was implemented.
- It was estimated that the initial implementation costs were $250,000 over a 4 month implementation period.[1]

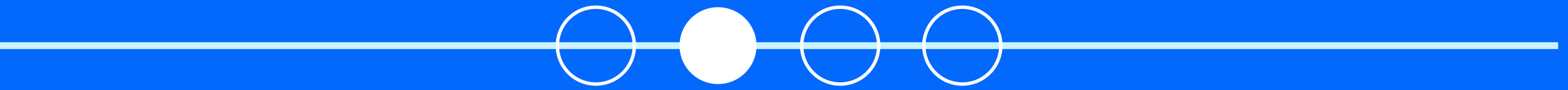
[1]*Rule Change Panel, Final Rule Change Report: Full Runway Cost Allocation of Spinning Reserve Costs, 30 April 2019*

Overview of the WEM arrangements

- In 2023, contingency reserve volumes were co-optimised with energy through the Frequency Co-optimised Essential System Services (FCESS) market, as part of broader WEMDE reforms.
- In response to price spikes following this change, a review of FCESS costs was conducted in 2024. It found that price spikes were primarily driven by issues in the inertia (RoCoF Control Service) market and from over-compensation arising from uplift payments when units were constrained at minimum generation.
- Structural changes in 2024 addressed uplift and pricing issues in essential system services. This, combined with large BESS entering the market, helped reduce costs thereafter.

WEM contingency raise price





Next steps

Next steps

Thank you for your participation in this technical working group discussion. The feedback from this discussion will help inform our draft determination. This is due to be published on 4 June 2026, in line with our statutory requirements.

Milestone	Date
Consultation paper published	20 November 2025
Close of submissions to consultation paper	18 December 2025
Extension to the draft determination published	26 March 2026
TWG meeting	1 April 2026
Draft determination publication date	4 June 2026
Submissions closing date	July 2026
Final determination publication date	August 2026

APPENDICES

NER clause 3.1.4 - Market design principles

This Chapter is intended to give effect to the following market design principles:

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;**
3. avoidance of any special treatment in respect of different technologies used by *Market Participants*;
4. consistency between *central dispatch* and pricing;
5. equal access to the market for existing and prospective *Market Participants*;
6. ***market ancillary services* should, to the extent that it is efficient, be acquired through competitive market arrangements and as far as practicable determined on a dynamic basis. Where dynamic determination is not practicable, competitive commercial contracts between *AEMO* and service providers should be used in preference to bilaterally negotiated arrangements;**
7. the relevant action under section 116 of the *NEL* or direction under clause 4.8.9 must not be affected by competitive market arrangements;
8. **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; and**
9. where arrangements provide for *AEMO* to acquire an *ancillary service*, *AEMO* should be responsible for settlement of the service.

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