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Department of **Mines, Industry Regulation and Safety**
Energy Policy WA

Cost Allocation Review

Information Paper

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Working together for a **brighter** energy future.

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Glossary

Term	Definition
AEC	Australian Energy Council
AEMO	Australian Energy Market Operator
BTM	behind-the-meter
CARWG	Cost Allocation Review Working Group
Coordinator	Coordinator of Energy
CRL	Contingency Reserve Lower
CRR	Contingency Reserve Raise
ECP	Expert Consumer Panel
EPWA	Energy Policy WA
ERA	Economic Regulation Authority
ESR	Electric Storage Resource
ESS	Essential System Services
IRCR	Individual Reserve Capacity Requirement
LFAS	Load Following Ancillary Services
MAC	Market Advisory Committee
MJA	Marsden Jacob Associates
MW	megawatt
MWh	megawatt hour
NCESS	Non-Co-optimised Essential System Services
NEM	National Electricity Market
PV	photovoltaic
RoCoF	Rate of Change of Frequency
SCADA	supervisory control and data acquisition
SWIS	South West Interconnected System
VRE	variable renewable energy

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

Unless otherwise defined, capitalised terms have the meaning prescribed in the WEM Rules.

Executive Summary

The Cost Allocation Review

The Coordinator of Energy (Coordinator), in consultation with the Market Advisory Committee (MAC), has reviewed the allocation of Market Fees and Essential System Services (ESS) costs to Market Participants. This review was conducted under clause 2.2D.1(h) of the Wholesale Electricity Market (WEM) Rules.

The purpose of the Cost Allocation Review was to make changes to the methods for allocating Market Fees and ESS costs to align them with the causer-pays principle, to the extent practicable and efficient.

The guiding principles for the Cost Allocation Review were that cost allocation methods should:

(1) meet the Wholesale Market Objectives;

(2) be cost-effective, simple, flexible, sustainable, practical, and fair;

(3) provide effective incentives to Market Participants to operate efficiently to minimise the overall cost to consumers;

(4) use the causer-pays principle, where practicable and efficient; and

(5) if the causer-pays principles is not practicable and efficient, then use the beneficiary-pays principle, where practicable and efficient.

Consultation

The MAC constituted the Cost Allocation Review Working Group (CARWG) to support the Cost Allocation Review. Information on the consultation that was undertaken on the Cost Allocation Review is available on the Energy Policy WA (EPWA) website,[1] including:

- the Scope of Work for the Cost Allocation Review;
- the Terms of Reference for the CARWG;
- papers and detailed minutes for all CARWG meetings and the relevant MAC meetings;
- a Cost Allocation Review Consultation Paper; and
- all submissions to the Consultation Paper.

This Information Paper

This paper presents the outcomes from the Cost Allocation Review and is organised as follows:

- Chapter 1 provides an introduction;
- Chapter 2 provides a summary of the consultation that was undertaken for the review;

1 The Cost Allocation Review web pages is https://www.wa.gov.au/government/document-collections/cost-allocation-review. The CARWG web page is https://www.wa.gov.au/government/document-collections/cost-allocation-review-working-group.

- Chapter 3 presents the review outcomes on the allocation of Market Fees;
- Chapter 4 presents the review outcomes on the allocation of Regulation services costs;
- Chapter 5 presents the review outcomes on the allocation of Contingency Reserve Raise (CRR) services costs;
- Chapter 6 presents the review outcomes on the allocation of Contingency Reserve Lower (CRL) services costs;
- Chapter 7 presents the review outcomes on the allocation of other ESS costs; and
- Appendix A presents a summary of the submissions to the Consultation Paper and EPWA's responses to those submissions.

Review Outcomes – Market Fees

No changes will be made to the current method for allocating Market Fees.

Rationale:

As indicated in the Consultation Paper, there may be some equity benefits to changing the method for allocating Market Fees. However, changing the allocation method is unlikely to impact on Market Participants' use of the relevant services and there would likely be material costs to make any changes. AEMO would have to develop new systems and procedures to implement any changes, and Market Participants would have to implement changes to their settlement and billing systems and make changes to their contractual arrangements.

Further, changing the method for allocating Market Fees would not increase the affordability, reliability, safety or security of supply and would provide no major identifiable benefit to Market Participants or end customers.

Consideration was given to charging Market Fees to Electric Storage Resources (ESR) based on only energy discharge (ignoring energy recharge). However, further consultation on this proposal indicated that such a change would:

- be difficult to implement (i.e., changes would need to be made to the billing algorithm for Market Fees);
- increase the Market Fees for other Market Participants (Market Generators and Loads);
- require separate metering for hybrid facilities with load, generation and ESR behind the meter;
- contribute to the incentive for ESR Facilities to co-locate with a load to minimise non-ESR consumption to avoid Market Fees; and
- be inconsistent with the treatment of generator systems, which can be net importers of energy for some Trading Intervals.

Review Outcomes – Regulation Services

Implement the WEM Deviation Method in October 2025, which is summarised as follows:

- Calculate the deviations for all Energy Producing Systems and Loads as the difference between:
    - their (real or implied) 4-second SCADA data; and
    - a straight line, as defined below.

- The line against which deviations are measured will differ for different Energy Producing Systems or Loads:
  - for Scheduled Facilities and Semi-Scheduled Facilities that provide ESS, it will be a straight line from the Facilities' metered MW levels at the start of the Dispatch Interval to their Dispatch Targets at the end of that Dispatch Interval;
  - for other Semi-Scheduled Facilities and Non-Scheduled Facilities, it will be a straight line from the Facilities' metered MW levels at the start of the Dispatch Interval and their injection forecast at the end of the Dispatch Interval, as determined by AEMO or the participant;
  - for Non-Dispatchable Loads with SCADA metering, it will be a straight line between the Facilities' metered MW levels at the start and end of the Dispatch Interval; and
  - for residual Non-Dispatchable Loads (those that do not have SCADA metering), it will be a straight line between:
    - the calculated MW level at the start of the Dispatch Interval; and
    - AEMO's overall Dispatch Forecast less the sum of the metered MW levels of Non-Dispatchable Loads with SCADA metering at the end of the Dispatch Interval.
- The implied SCADA metering quantity for the residual Non-Dispatchable Loads will be calculated by deducting the 4-second SCADA metering values for Loads measured by SCADA from the sum of all Energy Producing Systems' injection.
- AEMO will be responsible for determining the injection forecasts for Semi-Scheduled Facilities and Non-Scheduled Facilities. Participants will have the option to provide their own injection forecast for these facilities.
- The deviations for Scheduled Facilities and Semi-Scheduled Facilities will be adjusted to reflect any Regulation Raise or Lower services and any primary frequency response that they provide.
- Contribution factors for each Energy Producing System or Load will be calculated as the ratio of its deviations in a Dispatch Interval to the sum of all deviations in the Dispatch Interval.
- The contribution factors will be used to apportion Regulation costs to each Facility in a Dispatch Interval.
  - The Regulation costs allocated to the residual Non-Dispatchable Loads will be allocated among the Market Participants that serve the residual Non-Dispatchable Loads in their proportion to the aggregate consumption of loads over each Trading Interval.

Rationale:

As indicated in the Consultation Paper, the WEM Deviation Method is the preferred method to allocate Regulation service fees because:

- while the calculations are more complex than the current Regulation cost recovery method (under which the cost is allocated to Semi-Scheduled Facilities, Non-Scheduled Facilities and Non-Dispatchable Loads based on each Facility's share of the sum of metered consumption and generation in a Trading Interval), it is simpler to implement than the current and proposed causer-pays methods in the National Electricity Market;
- it provides incentives for Market Participants to minimise variability of their generation and loads, which helps to reduce Regulation requirements and overall costs;

- it avoids incentives for 'gaming' by Market Participants to avoid charges; and
- it does not conflict with existing WEM frameworks (i.e., primary frequency response, Tolerance Ranges and provision of Regulation ESS).

Detailed design of the WEM Deviation Method was developed, in consultation with the CARWG, to address specific issues raised by Market Participants – see section 4.4 of this paper.

Some Market Participants suggested that a cost-benefit analysis should be conducted before implementing the WEM Deviation Method. Analysis of the proposed WEM Deviation Method found that it:

- can be implemented at moderate cost to AEMO and Market Participants; and
- will provide incentives for generators to reduce Regulation requirements, which will deliver material cost savings to the WEM – see section 4.3.2 of this Paper for details.

Review Outcomes – Contingency Reserve Raise Services

Adjust the current Runway Method in Appendix 2A of the WEM Rules to separately allocate CRR costs to separate units within a Facility if each unit:

- can be dispatched independently; and
- has a separate network connection.

Rationale:

To ensure consistency with the causer-pays principle and to provide incentives for Market Participants to design their Facilities to minimise CRR requirements, the Facility Risk Value used in the Runway Method to allocate CRR costs should be amended to account for the lower risks associated with a Facility comprised of multiple units that have separate network connections. Applying the Runway Method to recover CRR costs on the basis of the aggregated units' risks over-estimating their Facility Risk Value and over-recovering CRR costs from the relevant Market Participant.

This proposal will not likely have an immediate impact on reducing CRR requirements but would more efficiently distribute the costs to the causers of CRR requirements, consistent with the causer-pays principle.

While it is unclear whether any existing facilities will benefit from these amendments, they may benefit new facilities in the future.

Review Outcomes – Contingency Reserve Lower Services

Revise the cost allocation method to:

- allocate CRL costs to Loads for consumption above 120 MW using the Runway Method;
- prorate CRL costs to Loads for consumption below 120 MW; and
- separately allocate facility and network risks.

Rationale:

As indicated in the Consultation Paper, applying a modified Runway Method to allocate CRL costs:

- is consistent with the causer-pays principle; and
- may give developers an incentive to reduce the size of the loads that they connect to the South West Interconnected System (SWIS) to reduce their exposure to CRL costs, resulting in an efficient market outcome.

This will be important given the potential for large loads, including large ESR, to connect to the SWIS. Connecting large loads to the system (including ESR) could substantially increase the CRL requirements and these loads should bear the additional costs associated with the increased CRL requirements they are causing.

A Market Participant raised a concern that the proposed method to allocate CRL costs may negatively impact incentives to invest in ESR. The CARWG considered several other options, but found that the other options would not meet one or more of the guiding principles.

Review Outcomes – Other ESS

Retain the current cost recovery methods for System Restart Services and Non-Co-Optimised ESS (NCESS).

Rationale:

Stakeholders supported retention of the current cost recovery methods for System Restart Services and NCESS but sought clarification on some issues (see section 7.1 of this paper).

Next Steps

Step	Timing
(1) Publish the draft WEM Amending Rules to reflect the outcomes indicated in this Information Paper	31 July 2023
(2) Submissions due on the draft WEM Amending Rules	15 August 2023
(3) Commencement of the WEM Amending Rules	1 October 2025

The timing for commencement of the WEM Amending Rules is to be aligned with commencement of the WEM Amending Rules to implement five-minute settlement on 1 October 2025.

1. Introduction

The Coordinator of Energy (Coordinator) conducted the Cost Allocation Review under clause 2.2D.1 of the Wholesale Electricity Market (WEM) Rules. Clause 2.2D.1(h) confers the function on the Coordinator to consider and, in consultation with the Market Advisory Committee (MAC), progress the evolution and development of the WEM and the WEM Rules.

The Cost Allocation Review was a review of the allocation of Market Fees and Essential System Services (ESS) costs to Market Participants.

1.1 Background

During the Energy Transformation Strategy reform process, some stakeholders identified issues with the allocation of Market Fees and ESS costs to Market Participants. However, time constraints during this process did not allow the Energy Transformation Taskforce to fully address all of these concerns.

Further, the MAC maintains a Market Development Forward Work Program to track and progress issues that have been identified by stakeholders. Several issues on the MAC's Market Development Forward Work Program relate to the allocation of market costs.

The MAC established the Cost Allocation Review Working Group (CARWG) to assist with the Cost Allocation Review.

The Cost Allocation Review is being conducted in four steps, three of which are now complete with the publication of this paper:

- Step 1 policy assessment (complete);
- Step 2: practicality assessment (complete);
- Step 3: methodology development (complete); and
- Step 4: draft rule changes.

Further information on the Cost Allocation Review can be found at Cost Allocation Review Working Group (www.wa.gov.au), including the detailed Scope of Works for the review, the Terms of Reference for the CARWG, meeting papers and minutes for all CARWG and relevant MAC meetings, the Cost Allocation Review Consultation Paper and all submissions on the Consultation Paper.

1.2 Purpose of this Paper

This paper sets out the Review Outcomes regarding the allocation of Market Fees and ESS costs to Market Participants. This paper is structured as follows:

- Chapter 1 provides an introduction, with background and next steps;
- Chapter 2 summarises the consultation that was conducted under the Cost Allocation Review;
- Chapter 3 presents the Review Outcome regarding the allocation of Market Fees;
- Chapter 4 presents the Review Outcome regarding the allocation of Regulation Raise and Lower service costs;
- Chapter 5 presents the Review Outcome regarding the allocation of Contingency Reserve Raise (CRR) service costs;

- Chapter 6 presents the final position for the allocation of Contingency Reserve Lower (CRL) service costs;
- Chapter 7 presents the Review Outcome regarding the allocation of other ESS costs, including System Restart Service and Non-Co-Optimised Essential System Services (NCESS) costs; and
- Appendix A presents a summary of the submissions to the Cost Allocation Review Consultation Paper and the Coordinator's responses to those submissions.

1.3 Next Steps

Step	Timing
(1) Publish the draft WEM Amending Rules to reflect the Review Outcomes	31 July 2023
(2) Submissions due on the draft WEM Amending Rules	15 August 2023
(3) Commencement of the WEM Amending Rules	1 October 2025

The timing for commencement of the WEM Amending Rules is to be aligned with commencement of the WEM Amending Rules to implement five-minute settlement on 1 October 2025.

2. Consultation

The Coordinator has consulted on the Cost Allocation Review through three avenues.

2.1 The Market Advisory Committee

The MAC is a committee of industry and consumer representatives convened under clause 2.3 of the WEM Rules to provide advice in relation to Rule Change Proposals, Procedure Change Proposals, and the evolution of the WEM and the WEM Rules.

On 14 December 2021, the MAC considered and endorsed the Scope of Work for the Cost Allocation Review and established the CARWG to provide analysis and support to the Coordinator in conducting the Cost Allocation Review.

The MAC considered the work undertaken by the CARWG and provided guidance to the CARWG and advice to the Coordinator at MAC meetings between 17 May 2022 and 8 June 2023.

Further information on the MAC, including all meeting papers and minutes can be found at https://www.wa.gov.au/government/document-collections/market-advisory-committee.

2.2 The Cost Allocation Review Working Group

The CARWG was established to provide detailed advice and analysis on all aspects of the allocation of Market Fees and ESS costs identified in the Scope of Work for the review, including:

- identification of issues with the current approach to the allocation of Market Fees and ESS costs, and options to address these issues;
- application of the causer-pays principle to Market Fees and ESS costs;
- review of Energy Policy WA's (EPWA) analysis underpinning the Cost Allocation Review; and
- support for the high-level and detailed design for changes to the approach to allocate Market Fees and ESS costs.

The CARWG met eight times between 9 May 2022 and 2 May 2023. The Terms of Reference for the CARWG, a list of CARWG members, and meeting papers and minutes for all CARWG meetings can be found at https://www.wa.gov.au/government/document-collections/cost-allocation-review-working-group.

2.3 The Consultation Paper

On 16 December 2022, the Coordinator published a Cost Allocation Review Consultation Paper that:

- set out the Coordinator's preliminary assessment of the current cost allocation methods against the guiding principles for the review, including whether the methods are aligned with the causer-pays principle;
- proposed options for cost allocation methods that are more consistent with the guiding principles, where it was determined that the methods did not meet the guiding principles;
- provided a quantitative assessment of the impact of the proposed options on Market Participant costs in comparison to the status quo; and
- set out some proposals for changes to the cost allocation methods in the WEM Rules, where relevant.

The Coordinator also published an International Review Paper on 16 December 2022 that provided further information on how Market Fees and ESS costs are allocated to Market Participants in seven jurisdictions outside of the WEM.

The submission period for the Consultation Paper closed on 9 February 2023. The Coordinator received 7 written submissions and one verbal/email submission. A high-level summary of the submissions is provided in Table 1.

A more detailed summary of the submissions and EPWA's response to those submissions is provided in Appendix A.

The Consultation Paper, the International Review Paper and submissions received on the Consultation Paper can be found at https://www.wa.gov.au/government/document-collections/cost-allocation-review.

Table 1: Summary of Submissions Regarding the Proposed Changes to the Cost Allocation Methods from the Consultation Paper

Participants' Position	Market Fees		Regulation Raise and Lower		CRR	CRL	System Restart	NCESS
	(1)(a) Retain the current method for allocating Market Fees to Market Participants	(1)(b) Ignore recharge energy when allocating Market Fees to storage facilities	(2)(a) Adopt the WEM Deviation Method to allocate Regulation costs in 2024/25	(2)(b) Reassess the new NEM Causer-Pays method to allocate Regulation costs in 2027, for potential implementation in 2028/29	(3) Where a Facility has multiple units with separate network connections, adjust the Runway Method to treat each unit separately	(4) Apply a modified Runway Method to allocate CRL costs	(5) Retain the current System Restart cost allocation method	(6) Retain the current NCESS cost allocation method
Support	Unanimous support.	Broad support. Perth Energy suggested allocating Market Fees based on recharge rather than discharge.	General support. AEMO favoured participants' providing ex ante forecasts to determine dispatch targets (including Semi-Scheduled Facilities) for applying the WEM Deviation Method.	Moderate support.	Broad support.	Broad support.	Broad support.	Broad support.
Opposed		AEMO recommended charging Electric Storage Resources (ESR) based on both withdrawal and injection.			Shell Energy did not support.	Neoen proposed (by email) alternative methods to allocate CRL costs.		

Participants' Position	Market Fees		Regulation Raise and Lower		CRR	CRL	System Restart	NCESS
	(1)(a) Retain the current method for allocating Market Fees to Market Participants	(1)(b) Ignore recharge energy when allocating Market Fees to storage facilities	(2)(a) Adopt the WEM Deviation Method to allocate Regulation costs in 2024/25	(2)(b) Reassess the new NEM Causer-Pays method to allocate Regulation costs in 2027, for potential implementation in 2028/29	(3) Where a Facility has multiple units with separate network connections, adjust the Runway Method to treat each unit separately	(4) Apply a modified Runway Method to allocate CRL costs	(5) Retain the current System Restart cost allocation method	(6) Retain the current NCESS cost allocation method
Clarification		Synergy asked how hybrid facilities will be treated. Shell Energy asked for an assessment of the benefits of the proposal.	Synergy and Alinta Energy asked for a cost-benefit assessment. The Australian Energy Council (AEC) suggested avoiding the imposition of extra costs on renewables.	AEC suggested that the new NEM Causer-New method should only be adopted if necessary. Several participants asked for cost-benefit analysis of this recommendation, including Synergy, Alinta Energy and Shell Energy.	AEMO asked for further work on practical implementation.		Synergy sought clarification on: (1) whether costs are recovered by a simple share of MWh, and (2) the treatment of ESR.	AEC wanted further analysis to understand whether penalties and refunds could be applied for facility Forced Outages that cause the NCESS requirement. Synergy said that cost signals could be provided to participants to minimise the requirement for this service.

Participants' Position	Market Fees		Regulation Raise and Lower		CRR	CRL	System Restart	NCESS
	(1)(a) Retain the current method for allocating Market Fees to Market Participants	(1)(b) Ignore recharge energy when allocating Market Fees to storage facilities	(2)(a) Adopt the WEM Deviation Method to allocate Regulation costs in 2024/25	(2)(b) Reassess the new NEM Causer-Pays method to allocate Regulation costs in 2027, for potential implementation in 2028/29	(3) Where a Facility has multiple units with separate network connections, adjust the Runway Method to treat each unit separately	(4) Apply a modified Runway Method to allocate CRL costs	(5) Retain the current System Restart cost allocation method	(6) Retain the current NCESS cost allocation method
Coordinator Response		Given the complexity of implementation, the Coordinator has revised the proposal. ESR will be charged on the basis on recharge and discharge (i.e., current practice).	A high-level cost-benefit analysis of the WEM Deviation Method is provided in this paper (see section 4.3.2).	If the WEM Deviation Method works as intended, then there may not be a need to implement the new NEM Causer-Pays method in the WEM in the future.	AEMO has indicated that there may be some existing facilities in the SWIS that could potentially benefit from this proposal.	Additional analysis was conducted of options to address concerns with the proposed Runway Method to allocate CRL costs.		
Final Position	Approved. No implementation required (status quo).	Revised.	Approved. WEM Deviation Method to be implemented in 2025.	EPWA to undertake a review of the new NEM Causer-Pays once it is implemented in the NEM (~2027).	Approved. Implement in 2025.	Approved. Implement in 2025.	Approved. No implementation required (status quo).	Approved. No implementation required (status quo).

3. Market Fees

3.1 Proposal in the Consultation Paper

The Consultation Paper made the following proposal.

Proposal 1 – Market Fees
(a) Retain the current method for allocating market services costs to Market Participants.
(b) Ignore recharge energy when allocating Market Fees to storage facilities.

As indicated in the Consultation Paper, there may be some equity benefits to changing the method for allocating Market Fees, but changing the allocation method is unlikely to impact on Market Participants' use of the relevant services and there would likely be material costs to make any changes. AEMO would have to develop new systems and procedures to implement any changes, and Market Participants would have to implement changes to their settlement and billing systems and make changes to their contractual arrangements.

Further, changing the method to allocate Market Fees would not increase the affordability, reliability, safety or security of supply and would provide no major identifiable benefit to Market Participants or end customers.

Under Proposal 1(b), grid connected ESR, including hybrid facilities, would only be charged for gross exports to the grid (equivalent to sent-out generation), rather than gross imports (ESR recharging) and gross exports (ESR discharging). The intent of this proposal was to ensure consistent treatment with competitive technologies, such as gas peaking plants.

3.2 Key Issues Raised in Submissions

All participants were in favour of proposals 1(a) and 1(b), except AEMO, who proposed to charge Market Fees to energy storage facilities using the current practice, based on grid withdrawal and injection.

AEMO's rationale for retaining the current cost recovery method for ESR included:

- it may be difficult to implement the proposed changes (i.e., changes to billing algorithm for Market Fees);
- as the current billing determinants are generation and consumption at the node, reducing cost recovery from loads by ignoring ESR recharge effectively puts a greater burden on other Market Participants (i.e., Market Generators and Market Loads);
- for a hybrid facility that has load, generation and ESR behind the meter, it would be difficult to identify ESR recharging, so separate metering would be required for the load and the ESR;
- an ESR Facility co-located with a load could attempt to minimise non-ESR consumption to avoid Market Fees; and
- generation facilities are charged Market Fees for any consumption during their synchronisation, or periods of consumption when not operating/undertaking repairs, or when creating inertia by consuming energy to spin the turbines. The proposal would create an inconsistency in the treatment of generating systems, which can be net importers of energy for some Trading Intervals and ESR facilities.

3.3 How the Issues have been Addressed

The Coordinator acknowledges and agrees with the issues raised by AEMO, particularly the cost to implement the change and the difficulty of applying the proposal to hybrid facilities, which are likely to increase in the future.

3.4 Review Outcomes – Market Fees

No changes will be made to current method for allocating Market Fees.

4. Regulation Services

4.1 Proposal in the Consultation Paper

The Consultation Paper made the following proposal.

Proposal 2 – Regulation
(a) Implement the WEM Deviation Method to allocate Regulation costs in 2024/25, following the implementation of the new WEM arrangements on 1 October 2023, subject to a cost/benefit analysis. (b) Reassess adoption of the new NEM Causer-Pays Method to allocate Regulation costs in 2027, for potential implementation in 2028/29.

Under Proposal 2(a), the WEM Deviation Method would be implemented using:

- SCADA data to measure deviations from linear dispatch targets in a 30-minute period; and
- summation of the absolute value of deviations from the linear target.

As indicated in the Consultation Paper, the WEM Deviation Method is the preferred method to allocate Regulation Raise and Lower service fees because:

- while the calculations are more complex than the current Regulation cost recovery method (under which the cost is allocated to Semi-Scheduled Facilities, Non-Scheduled Facilities and Non-Dispatchable Loads based on each Facility's share of the sum of metered consumption and generation in a Trading Interval), it is simpler to implement than the current and proposed causer-pays methods in the National Electricity Market;
- it provides incentives for Market Participants to minimise variability of generation and loads;
- it does not provide incentives for 'gaming' by Market Participants to avoid charges; and
- it is consistent with existing WEM concepts (i.e., primary frequency response, Tolerance Ranges and Regulation ESS).

4.2 Key Issues Raised in Submissions

Participants had the following concerns with Proposal 2(a):

- measuring deviations from a linear dispatch target in a 30-minute period is inconsistent with the 5-minute dispatch periods under the new Real-Time Market;
- even if the measurement of deviations were adjusted to 5-minute Dispatch Targets, which are established by the Wholesale Electricity Market Dispatch Engine (WEMDE) for Scheduled Facilities and for Semi-Scheduled Facilities that provide Frequency Co-Optimised Essential System Service ESS, there are no Dispatch Targets for Semi-Scheduled or Non-Scheduled Facilities, or Non-Dispatchable Loads; and
- a cost-benefit analysis should be undertaken to demonstrate that adopting a causer-pays methodology, like the WEM Deviation Method, will change Market Participant behaviour and reduce the requirement for Regulation Raise and Lower services and that these benefits will exceed implementation costs for AEMO and Market Participants.

4.3 How the Issues have been Addressed

4.3.1 Changes to the WEM Deviation Method

The following changes to the WEM Deviation Method were discussed by the CARWG on 2 May 2023:

- apply the method to each 5-minute Dispatch Interval, consistent with the Real-Time Market;
- use the Dispatch Target from WEMDE for each 5-minute Dispatch Interval to set the targets for Scheduled Facilities and Semi-Scheduled Facilities that provide ESS;
- AEMO could be made responsible for determining injection forecasts for each Semi-Scheduled Facility and Non-Scheduled Facility, consistent with current default practices in the NEM for applying the Frequency Control Ancillary Services (FCAS) causer-pays method;
- Facilities could have the option to provide their own forecasts rather than rely on AEMO default forecasts;
- Facilities that are scheduled to provide Regulation Services could be excluded from any liability under the WEM Deviation Method (up to the quantity of Regulation they provide) and any non-performance in the provision of Regulation Services will be managed under the relevant WEM Rules/Procedures; and
- AEMO would need to develop a method to exclude from the WEM Deviation method any deviations that result from Facilities providing primary frequency response.

If Market Participants can provide more accurate forecasts for Semi-Scheduled Generators than AEMO's default forecasts, this could help reduce the future requirements for Regulation services.

Conversely, if Market Participants do not provide credible forecasts, AEMO will utilise its default forecasts for Semi-Scheduled Generation.

4.3.2 High Level Cost Benefit Analysis

The Consultation Paper stated that a cost-benefit analysis of the WEM Deviation Method should be undertaken before accepting the recommendation to adopt a new cost allocation method.

This section provides a high-level qualitative cost-benefit analysis of adopting the WEM Deviation Method.

The implementation costs for the WEM Deviation Method are likely to be moderate for AEMO and Market Participants because:

- WEMDE will set 5-minute Dispatch Targets for Scheduled Facilities and Semi-Scheduled Facilities providing ESS from the commencement of the new WEM on 1 October 2023;
- AEMO will set default injection forecasts for Semi-Scheduled and Non-Scheduled Facilities, which would reduce the cost burden on Market Participants;
- Market Participants can opt to develop their own forecasts, but this is not required; and
- AEMO does not need to develop an expensive system to apply the WEM Deviation Method to calculate causer pays factors.[2]

[2] A spreadsheet model has been used since 2001 to operate the current NEM Causer-Pays method, which is a considerably more complicated algorithm than the WEM Deviation Method.

While the costs of implementing the WEM Deviation method are modest, the costs of providing Regulation Raise and Lower services in the WEM are rising rapidly, which provides a justification for implementing a causer-pays method to help minimise further increases in these requirements.

As demonstrated in Table 2, Load Following Ancillary Services (LFAS) requirements have increased substantially since 2018/19.

Table 2: Historical LFAS Requirements (MW)

Year	Peak LFAS requirement	Peak LFAS implemented by AEMO	Off Peak LFAS requirement	Off Peak LFAS implemented by AEMO
2018/19[3]	72	NA	72	NA
August 2019 to September 2020[4]	85	85	50	50
September 2020 to July 2021[5]	105	95	70	70
July 2021 to June 2022[6]	110	100	65	65
July 2022 to December 2022[7]	110	110	65	NA

Source: AEMO, Ancillary Service Reports

Analysis undertaken by AEMO has indicated that increases in the LFAS requirement in the WEM are partly due to increased variable renewable energy (VRE). This is demonstrated in Figure 1, which shows that increases in the capacity of solar photovoltaic (PV) and grid connected renewables has resulted in requests by AEMO to the Economic Regulation Authority (ERA) to increase the Peak LFAS requirement. Most of the increases in the LFAS requirements have been implemented, although AEMO has delayed the implementation of the increased LFAS requirement in some circumstances.[8]

3 Price periods are constant across all time periods.

4 The Peak Period is between 5:30am and 7:30pm and the Off Peak Period between 7:30pm and 5:30am.

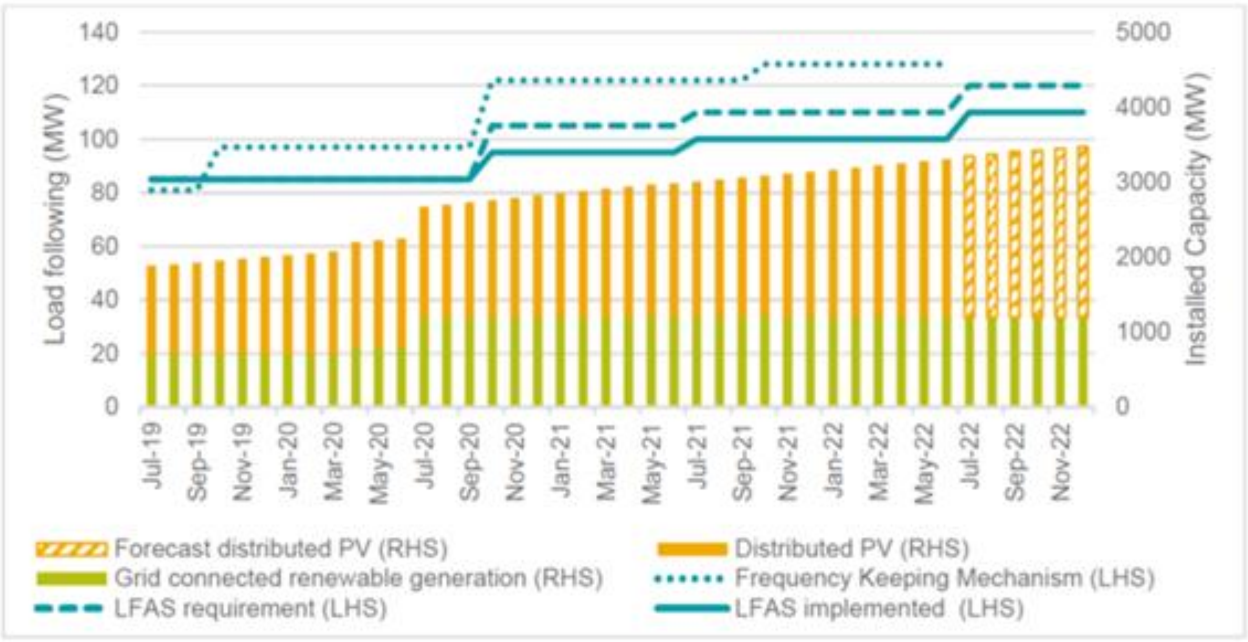
5 The Peak Period is between 5:30am and 7:30pm and the Off Peak Period between 7:30pm and 5.30am.

6 The Peak Period is between 5:30am and 8:30pm and the Off Peak Period between 8:30pm and 5.30am.

7 The Peak Period is between 5:30am and 8:30pm and the Off Peak Period between 8:30pm and 5:30am.

8 Some delays occur because of the difficulty of estimating the impact of additional renewables and distributed PV on Regulation requirements (and reliability) and when the increase in Regulation requirements needs to be implemented.

Figure 1: Peak LFAS Requirements and the Level of VRE in the SWIS



Source: ERA, Decision on the AEMO's 2022/23 ancillary services requirements, 27 June 2022, p. 11.

Implementing a causer-pays method to allocate Regulation services costs has the potential to change Market Participant behaviour and reduce future requirements for Regulation services. The potential avoided costs of increasing future Regulation requirements in the WEM are substantial:

- the ERA estimated that a 10 MW increase in the LFAS quantity from July 2021, from ±100 MW to ±110 MW could cost an additional $5.6 million (8.3%) over a 12-month period;[9]
- AEMO estimated that a further increase in LFAS requirements, from ±110 MW to ±120 MW could increase costs by a further $7.4 million (10.2%) annually;[10] and
- Marsden Jacob Associates (MJA) estimated that cumulative increases in Regulation service requirements could result in costs increasing by $43.3 million by 2026/27 (see Table 3).

If the WEM Deviation Method can help reduce Regulation requirements by ±10 MW, then annual savings of around $7.4 million can be achieved with a modest increase in implementation and operational costs.

9 ERA, Decision on the AEMO's 2022/23 ancillary services requirements, 27 June 2022, p. 14.

10 Ibid.

Table 3: Future Costs of Peak Regulation Requirements[11]

Year	Peak Regulation Requirements (MW)	Annual Cost ($ millions)	Annual Cost Increase ($ millions)	Cumulative Cost Increase ($ millions)
2021-22	99	35.17		
2022-23	110	39.26	4.09	4.09
2023-24	120	42.82	3.57	7.66
2024-25	140	49.96	7.14	14.80
2025-26	170	60.67	10.71	25.50
2026-27	220	78.51	17.84	43.34

Source: Marsden Jacob 2023

While the avoided further increases in Regulation services costs are substantial, adopting a causer-pays cost allocation mechanism for Regulation Raise and Lower will help to reduce the future Regulation requirements.

Analysis has indicated that adopting the WEM Deviation Method could result in the following contribution factors (i.e., cost recovery level) for each facility type in the WEM:

- Loads will bear about 50% of the Regulation Raise and Lower costs (loads bear around 90% under the current cost recovery method);
- grid connected Energy Producing Systems will bear the other 50% of costs, and for the grid connected facilities:
  - about 47% of costs will be attributed to wind farms;
  - about 5.4% will be borne by solar farms in the SWIS; and
  - the balance (47.6%) will be borne by coal and gas generators.

The higher contribution factor (cost recovery percentage) for wind farms is due to there being a significantly higher installed capacity of wind (1,034 MW) than solar (141 MW) generation in the SWIS. The contribution factor per unit of installed capacity in the SWIS is significantly higher for wind farms (4.54% increase in contribution factor per MW) than for solar farms (0.35% increase in contribution factor per MW) due to the higher variability of wind generation within a 5-minute dispatch period compared to solar farm generation.

11 Notes:

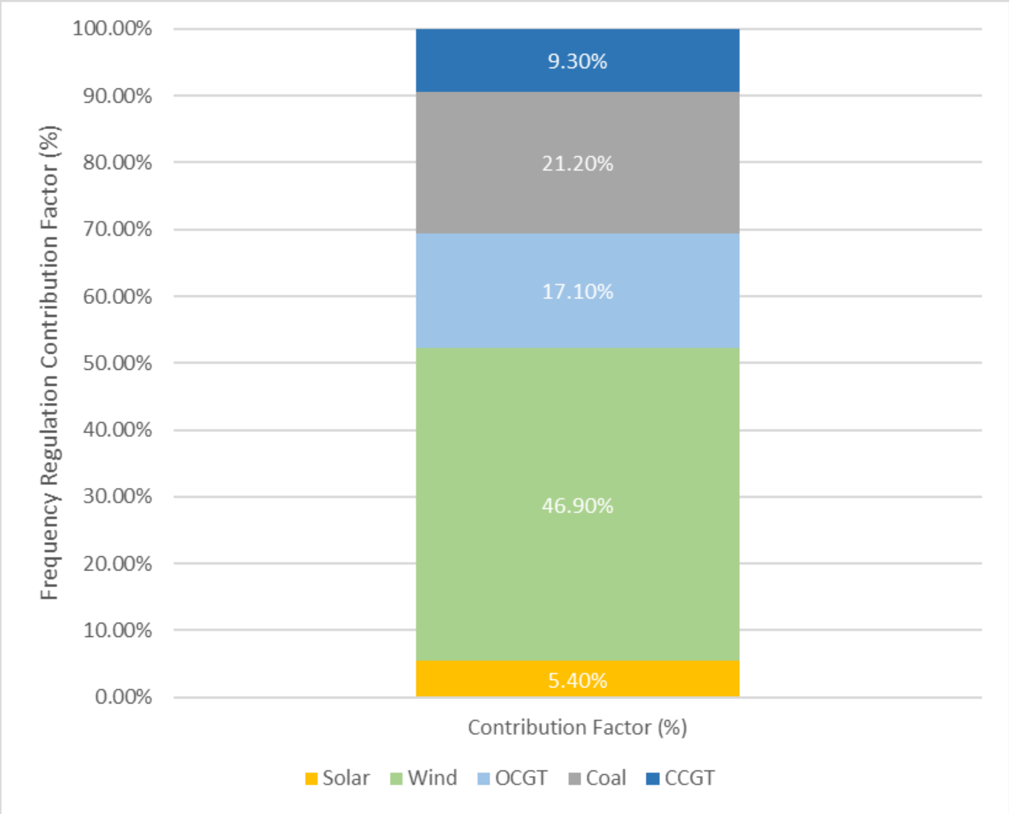
(a) MJA estimated future peak Regulation Requirements given the increase in the amount of VRE capacity that will connect to the SWIS by 2026-27.

(b) Using average LFAS Up and LFAS Down prices in the 2021/22 year (April 2021 to March 2022), MJA calculated the annual cost increase due to increased future Peak Regulation Requirements; and

(c) These estimates are based on increases in average FCAS costs, so these estimates will likely be below the incremental cost estimates calculated by the ERA and AEMO (see the previous page).

These estimated contribution factors are illustrated in Figure 2.

Figure 2: Regulation Contribution Factors – by Facility Type



Source: Marsden Jacob 2023

Applying contribution factors determined under the WEM Deviation Method provides an incentive for generators to minimise deviations between forecast and actual generation and potentially reduce Regulation service requirements. Actions that generators could take to minimise deviations include:

- Scheduled Facilities and Semi-Scheduled Facilities providing ESS must follow Dispatch Targets in the new market and will face costs if they deviate from the 5-minute Dispatch Interval target;
- Semi-Scheduled Facilities could provide more accurate generation forecasts (considering weather related factors), which would help to minimise forecast errors and regulation requirements; and
- Semi-Scheduled Facilities could minimise variations in their metered injections by installing onsite storage.

Projects funded by the Australian Renewable Energy Agency have demonstrated the potential for reducing future FCAS costs in the NEM. The Proa Solar Farm Short Term Forecasting Project has demonstrated how better forecasting has substantially reduced causer-pays factors for the Kidston Solar Project from of 0.383 to 0.200 (average over 5 months). This reduction in the causer-pays factor represents a 52% reduction in regulation costs for the Kidston Solar Project.[12]

12 https://arena.gov.au/assets/2020/07/proa-analytics-solar-forecasting-lessons-learnt-report-2.pdf

While better forecasting has the potential to reduce Market Participant Regulation costs, it can also reduce the Regulation requirement, since better short-term solar forecasting (ex-ante forecasts) means greater certainty of demand and supply for each 5-minute Trading Interval. This helps to reduce the Regulation requirement that is used to manage supply and demand deviations.

4.4 Review Outcomes – Regulation Services

Implement the WEM Deviation Method in October 2025 based on the following design.

4.4.1 Calculation of Regulation Contribution Factors by Facility using the WEM Deviation Method

Regulation costs will be allocated to Energy Producing Systems and Loads based on deviations from average energy production or load over a 5-minute Dispatch Interval. This will be based on 4-second SCADA data (metered or implied) and measured as actual deviations from a hypothetical linear dispatch target that is calculated ex-post (i.e., average energy production or load over a 5-minute Dispatch Interval). The steps for the WEM Deviation Method are:

(1) Calculate the deviations for Scheduled Facilities and Semi-Scheduled Facilities providing ESS as the difference between:

- the SCADA metering data for each Facility; and
- a straight line between the Facility's metered MW levels at the start of the Dispatch Interval and its Dispatch Target at the end of that Dispatch Interval.

Dispatch Targets for Scheduled Facilities and Semi-Scheduled Facilities providing ESS will be set in the Real-Time Energy Market, based on a 5-minute Dispatch Interval.

(2) Calculate the deviations for other Semi-Scheduled Facilities and Non-Scheduled Facilities[13] as the difference between:

- the SCADA metering data for each Facility; and
- a straight line from the Facility's metered MW level at the start of the Dispatch Interval and its injection forecast at the end of the Dispatch Interval.

See section 4.4.3 for more information on injection forecasts.

(3) Calculate the deviations for Non-Dispatchable Loads with SCADA metering as the difference between:

- the SCADA metering data for the Facility; and
- a straight line between the Facility's metered MW level at the start and end of the Dispatch Interval.

(4) Calculate the deviations for the residual Non-Dispatchable Loads (i.e., the Non-Dispatchable Loads that do not have SCADA metering) as the difference between:

- the implied SCADA metering quantity for the residual Non-Dispatchable Loads (see below); and

13 It is assumed that all registered Non-Scheduled Facilities (generators less than 10 MW and ESR less than 5 MW) have SCADA metering. EPWA will confirm this and changes may need to be made the WEM Deviation Method if there are Non-Scheduled Facilities that do not have SCADA metering.

- a straight line between:
  - their calculated MW level at the start of the Dispatch Interval; and
  - AEMO's overall Dispatch Forecast less the metered MW levels for Non-Dispatchable Loads with SCADA metering at the end of the Dispatch Interval.

The implied SCADA metering quantity for the residual Non-Dispatchable Loads will be calculated by deducting the sum of the 4-second SCADA metering values for all Scheduled Facilities (Loads only) and Non-Dispatchable Loads from the sum of all Energy Producing Systems injection quantities.[14]

(5) Contribution factors for each Energy Producing System or Load will be calculated as the ratio of its deviations in a Dispatch Interval to the sum of all deviations in each Dispatch Interval.

(6) The contribution factors will be used to apportion Regulation costs to each Energy Producing System or Load in a Dispatch Interval.

(7) The Regulation costs that are apportioned to the residual Non-Dispatchable Loads for each Dispatch Interval will be aggregated to a Trading Interval and then allocated to each Market Participant that serves any of the residual Non-Dispatchable Loads based on their proportion of the aggregate MWh consumption in each Trading Interval.

(8) For settlement purposes, the Regulation costs for each Market Participant will be calculated over the 7-day billing cycle.

A weekly billing cycle provides timely feedback to Market Participants so that they can factor the costs incurred over that billing cycle into their future operations and forecasts, which will minimise generation and load deviations per Facility in subsequent billing cycles. Theoretically, if individual Facilities are able to minimise all deviations, then 100% of Regulation costs could be allocated to residual Non-Dispatchable Loads. However, this outcome is highly unlikely as the investment in grid connected intermittent generation increases in the SWIS.

4.4.2 Adjustments for Facilities Providing ESS and Primary Frequency Response

Scheduled Facilities and Semi-Scheduled Facilities that are cleared by the co-optimised Real Time Market to provide Regulation Raise and Lower services will have their deviations reduced by the amount of Regulation services that they provide in a Dispatch Interval. Any non-performance in the provision of Regulation services will be managed under the relevant WEM Rules/Procedures.

Primary frequency response is necessary to ensure that system frequency is kept within the Normal Operating Frequency Band. Facilities that provide primary frequency response will have their deviations adjusted so that this response is not considered in the calculation of their deviations.

4.4.3 Responsibility for Creating Injection Forecasts

Application of the WEM Deviation Method will require the creation of injection forecasts for Semi-Scheduled Facilities that do not provide ESS and Non-Scheduled Facilities.

AEMO will be responsible for determining these injection forecasts.

[14] Non-Dispatchable Loads will not be loss factor adjusted because the WEM Deviation Method is only concerned with deviations from a straight line trajectory and not absolute values (MW).

Semi-Scheduled Facilities that do not provide ESS and Non-Scheduled Faculties will have the option to provide their own injection forecasts rather than rely on AEMO default injection forecasts. If participants do not provide credible forecasts, then AEMO will utilise the default forecasts in the WEM scheduling and dispatch processes.

5. Contingency Reserve Raise Services

5.1 Proposal in the Consultation Paper

The Consultation Paper made the following proposal.

Proposal 3 – Contingency Reserve Raise
Application of the Runway Method should be adjusted to cater for situations in which a Facility is comprised of multiple units each with a separate network connection. In this situation, each unit should be treated separately in the runway method (i.e., they should have separate Facility MW for the purposes of CRR cost recovery).

To ensure consistency with the causer-pays principle and to provide incentives for Market Participants to design the Facility to minimise CRR requirements,[15] the Facility Risk Value used in the Runway Method to allocate CRR costs should be amended to account for the lower risks associated with a Facility comprised of multiple units that have separate network connections, where appropriate.

In certain circumstances, the multiple units should not be aggregated when applying the Runway Method to recover CRR costs, as aggregating the units would over-estimate their Facility Risk Value and over-recover CRR costs from the relevant Market Participant.

Under this proposal, AEMO is required to assess whether the multiple dispatchable units at a Facility are likely to have a simultaneous outage using, for example, the following steps:

1. Does each dispatchable unit (or set of inverters) have its own onsite electrical distribution system (or set of inverters)?

The dispatchable units use a common onsite electrical distribution system → An outage of the onsite electrical infrastructure will likely result in an outage for all of the units → Treat the units as a single unit under the Runway Method

Each dispatchable unit has a separate onsite electrical distribution system → Move to step 2

2. Does each dispatchable unit have a separate network connection?

The multiple dispatchable units have the same network connection → Treat the units as a single unit under the Runway Method

The multiple dispatchable units all have separate network connections (e.g. a solar farm that has a separate network connection for each set of inverters) → Assign a Facility Risk Value to each dispatchable unit and calculate the Contingency Reserve Raise liability at the dispatchable unit level (not the Facility level)

15 Incentivising participants to design their Facilities to have separate network connections for each independent unit of their Energy Producing System will help to reduce Facility Risks (caused by the outage of either the network connection or the unit) below the maximum sent out capacity of the facility, which could lower CRR requirements.

5.2 Key Issues Raised in Submissions

AEMO agreed that it should have discretion to establish criteria to determine when to treat units of facilities with multiple connections separately for allocation of CRR costs and that the method for making this determination should be specified in a WEM Procedure. It was proposed to amend the WEM Rules to require AEMO to include this assessment in a WEM Procedure.

While AEMO agreed that facilities with units that have separate connection points may represent a lower risk, the proposed approach of treating each unit within a Facility separately may require substantial changes to the registration framework.

It is currently unclear whether any existing facilities will benefit from the proposal. However, it is likely that some facilities will benefit in the future due to increased investment in renewable facilities to achieve net zero emissions in the SWIS by 2050. This could include wind or solar farms that have individual sets of inverters with a separate network connections.

AEMO also sought more guidance on the application of this proposal in practice.

5.3 How the Issues have been Addressed

AEMO raised concerns that the creation of separate dispatchable units for a single Facility would require major changes to the registration framework. However, each set of inverters will only be treated as a separate unit for application of the Runway Method for CRR cost recovery, not for WEM participation.

Given that some existing facilities may benefit from the proposal, and that more facilities are likely to benefit in the future, there is a compelling case for proceeding with the proposal.

This proposal will not likely have an immediate impact on reducing CRR requirements but would more efficiently distribute the costs to the causers of CRR requirements, consistent with the causer-pays principle.

Further work is required to clarify the proposal, which would include:

- delineating between risk at separate connection points for a facility comprising multiple units, which could be managed using SCADA similar to the current treatment of Intermittent Loads; and
- changes to the Facility Registration process to ensure that AEMO has the necessary information to implement this proposal.

5.4 Review Outcomes – Contingency Reserve Raise Services

Adjust the Runway Method to separately allocate CRR costs to separate dispatchable units within a Facility if each unit

- has its own onsite electrical distribution system (or set of inverters); and
- has a separate network connection.

The Amending Rules will insert a head of power for a WEM Procedure that will require AEMO to develop methodology to implement this Review Outcome.

6. Contingency Reserve Lower Services

6.1 Proposal in the Consultation Paper

The Consultation Paper made the following proposal.

Proposal 4 – Contingency Reserve Lower
Apply a modified Runway Method to allocate CRL costs. If a Network Contingency sets the CRL requirement in a trading interval, the costs of procuring contingency reserves are proposed to be split into two components (Load CRL and Network CRL) and costs are proposed to be allocated as follows: (1) Load CRL cost allocation: • apply a runway method to allocate the individual load component of CRL costs, treating all loads with capacity less than or equal to 120 MW as if they were a single 120 MW load; and • apply the existing allocation method to allocate load CRL costs (pro-rata based on energy consumption) to loads with capacity less than or equal to 120 MW. (2) Network CRL cost allocation as follows: • apply a runway method to allocate the network component of CRL costs to loads in excess of 120 MW (if there is only one large load in excess of 120 MW, that load sets the Network Contingency and will bear 100% of Network CRL costs). If a Load Contingency sets the Contingency Reserve Requirement in a trading interval, only the Load CRL cost allocation (1) process will be used.

As indicated in the Consultation Paper, applying a modified Runway Method to allocate CRL costs:

- is consistent with the causer-pays principle; and
- may give developers an incentive to reduce the size of the loads that they connect to the SWIS to reduce their exposure to CRL costs, resulting in an efficient market outcome.

This will be important given the potential for large loads (e.g. large size ESR) to connect to the SWIS. Connecting large loads to the system could substantially increase the CRL requirements and these loads should bear the additional costs associated with the increased CRL requirements.

6.2 Key Issues Raised in Submissions

At the 21 March 2023 CARWG meeting, EPWA discussed the use of the Runway Method to allocate CRL costs to Loads above a 120 MW threshold.

Some CARWG members raised concerns with this proposal:

- a full causer-pays cost allocation under the Runway Method could result in the initial large size ESR paying up to 60-70% of CRL costs when recharging, which would place a significant cost burden on ESR systems;
- ESR are needed to firm up VRE to replace retiring coal plant, and these charges could be a significant barrier to entry in the WEM;
- information from the NEM suggested that the probability of an ESR having a forced outage is low (https://arena.gov.au/knowledge-bank/lake-bonney-operational-report-2/), so it is unlikely that an ESR would contribute to an increase in the CRL service requirement; and

- the most likely cause of an increase in the CRL service requirement is a transmission asset outage, which results in the ESR not being able to recharge during the outage.

There are significant network constraints on the SWIS currently, which increases the likelihood of an ESR locating on common transmission assets. Large loads locating on common transmission assets (i.e., a 330 kV line) would significantly increase CRL service requirements.

While the facility outage risk may be low, the network outage risk could be higher and AEMO would have to establish the CRL service requirement on the basis of the aggregate of discrete loads (i.e., ESR, mineral processing loads, etc.) on that common transmission asset. This establishes a strong case to apply the Runway Method to large loads (above 120 MW) to ensure that they have incentives to reduce the size of individually connected loads and to reduce the future CRL service requirements.

6.3 How the Issues have been Addressed

The CARWG identified an option to set the CRL requirements based only on the network risk (instead of separately allocating facility and network risk) because a focus on the network risk reflects the likelihood of a network outage impacting an ESR/large load, not a facility outage (which has a low likelihood for ESR).

This option was discussed with AEMO, which indicated that:

- while the facility risk for a grid connected ESR is low, the risk exists and cannot be ignored when setting CRL requirements – AEMO will factor in both facility and network risks when establishing the CRL requirement; and
- this proposal ignores other types of loads that may be above 120 MW and that could have a material facility risk (i.e. new mining loads or hydrogen production facilities).

EPWA undertook an assessment of CRL cost recovery to see if the burden of cost recovery could be reduced for a grid connected ESR. Three cost recovery options were considered:

- Option 1 – prorating based on energy consumed in a trading interval (the current allocation method);
- Option 2 – apply the Runway Method above 120 MW and prorate below 120 MW, and separately allocate facility and network risks (the option presented to the CARWG on 21 March 2023); and
- Option 3 – apply the Runway Method above 120 MW and prorate below 120 MW, but only allocate costs according to the network risk (the option identified by the CARWG on 21 March 2023).

The following new entry assumptions were made for grid connected ESR:

- Scenario 1 – entry of a 400 MW ESR1 and a 200 MW ESR2 on separate network elements; and
- Scenario 2 – entry of a 400 MW ESR1 on one network element and two 200 MW ESR2 and ESR3 on another network element.

Other assumptions:

- 15 large commercial loads between 11 MW and 120 MW are modelled separately;
- small loads (<10MW each) are aggregated to 950 MW; and
- there are two networks with the large commercial loads distributed randomly across the two networks and half of the small loads on each network.

6.3.1 Analysis of Scenario 1

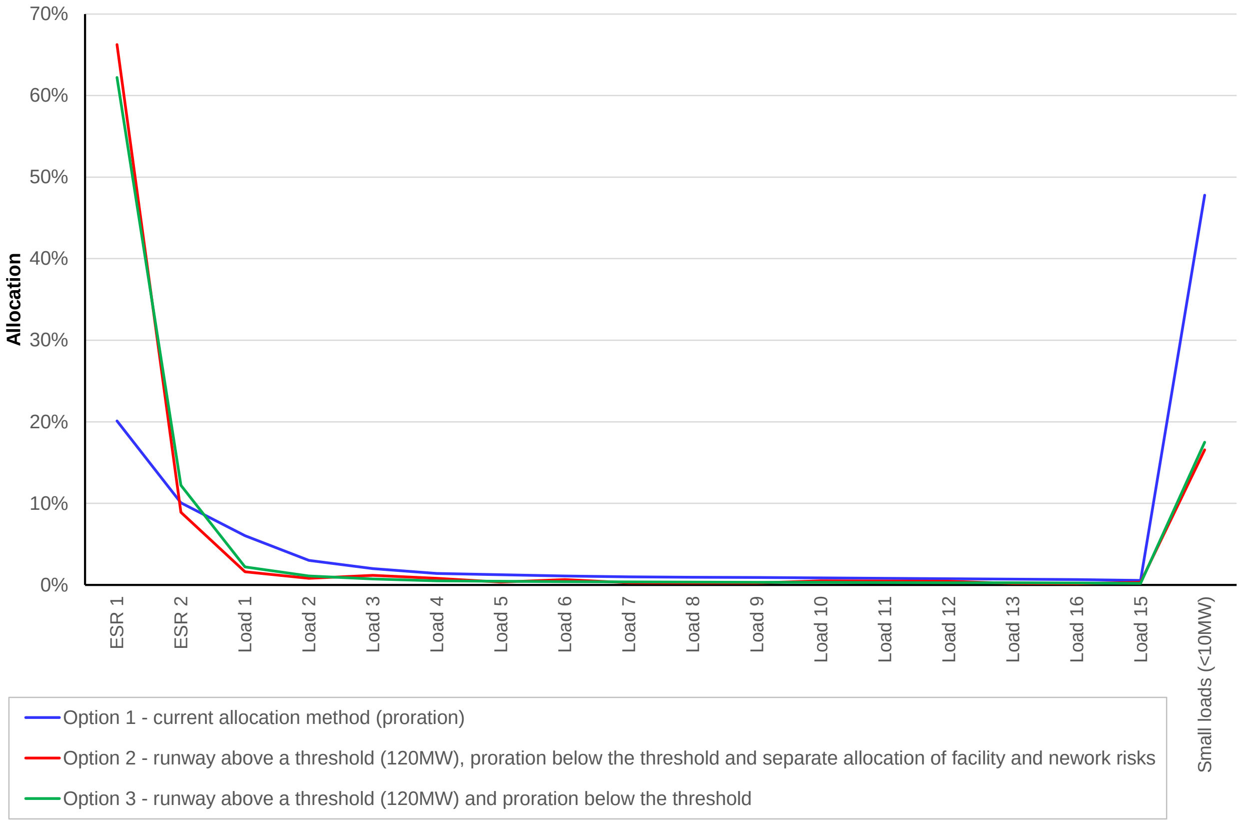
Under the current method (Option 1), ESR1 is allocated 20.1% of CRL costs when recharging and ESR2 is allocated 10.1% when recharging.

Under a full causer-pays cost recovery method (Option 2), ESR1 is allocated 66.2% of CRL costs and ESR2 is allocated 8.9%. This highlights that the Runway Method allocates the majority of costs to the largest unit that is operating. However, the largest load that is consuming is also causing an increase in the CRL service requirement, so adopting a causer-pays approach means the largest ESR would bear that cost.

Under Option 3, in which costs for the CRL requirement are allocated based only on network risk (not individual load risk), ESR1 is allocated 62.2% and ESR2 is allocated 12.2%.

The results for Scenario 1 are presented in Figure 3.

Figure 3: CRL Cost Recovery under Scenario 1



Source: EPWA 2023

The results for Option 2 and Option 3 are similar under Scenario 1 because the ESR facilities are on different network elements, which suggests that their impact on the CRL service requirements is similar (set at 549 MW) for both options. As a result, applying the Runway Method under Option 2 and Option 3 yields similar results.

6.3.2 Analysis of Scenario 2

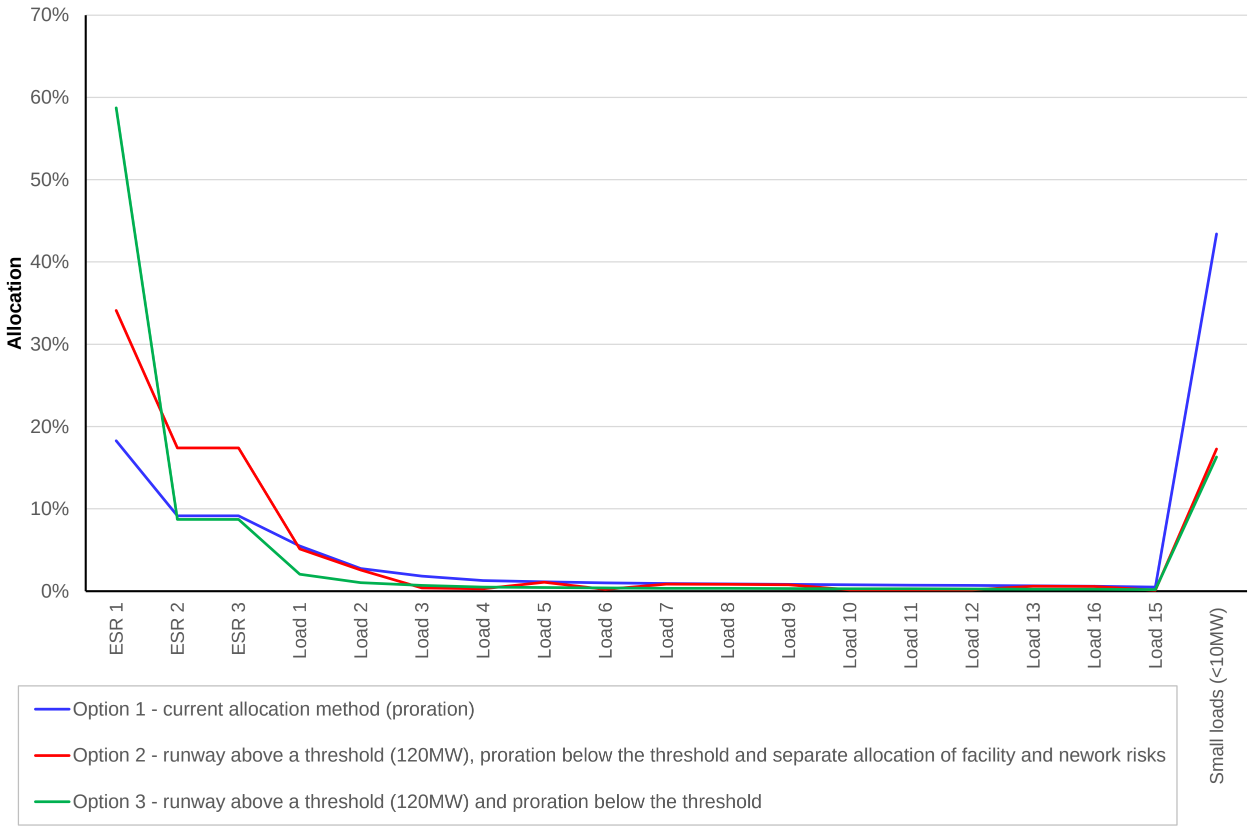
Under the current method (Option 1), ESR1 is allocated 18.3% of CRL costs when recharging, while ESR2 and ESR3 are each allocated 9.1% when recharging.

Under a full causer-pays cost recovery method (Option 2), ESR1 is allocated 34.1% of CRL costs, while ESR2 and ESR3 are each allocated 17.4%. The cost allocation to ESR2 in Scenario 2 is significantly higher than in Scenario 1 (8.9%) because the network risk for ESR2 has increased, because ESR2 and ESR3 are located on a common transmission element. While the CRL requirement has not increased overall (still 549 MW), ESR2 now bears more of the CRL costs compared to Scenario 1.

Under Option 3, in which costs for the CRL requirement are allocated based only on network risk (not the ESR facility risk), ESR1 is allocated 58.7% of the CRL costs, while ESR2 and ESR3 are each allocated 8.7%.

The results for Scenario 2 are presented in Figure 4.

Figure 4: CRL Cost Recovery under Scenario 2



Source: EPWA 2023

Under Option 3, ESR1 would bear most of the CRL costs because it is the largest unit (400 MW). However, while ESR2 and ESR3 create a combined 400 MW CRL requirement by locating on a common transmission element, they would not provide a cost-reflective contribution to CRL cost recovery.

6.3.3 Summary of Options

In summary:

- Options 2 and 3 yield significantly higher cost allocations to large loads compared to the current cost allocation method (Option 1) in both scenarios. This is consistent with the causer-pays principle, whereby large loads (i.e., ESR in the above scenarios) that connect to the SWIS pay for the increase in CRL service requirements that they cause.
- Options 2 and 3 yield similar cost allocations if grid connected ESR are located on separate transmission elements. Cost recovery from ESR1 was between 62.2% and 66.2%. In effect, the largest load that is operating determines most of the requirement for the CRL service.

- Options 2 and 3 yield very different results if grid connected ESR share transmission infrastructure. In Scenario 2, with ESR2 and ESR3 sharing a common transmission element, cost recovery was 34% for ESR1, and 34% in aggregate for ESR2 and ESR3 (17% each). Under Option 3, ESR1 would bear 58.7% of CRL service costs.

In conclusion, Option 3, is not consistent with the causer-pays principle because it allocates most CRL costs to the largest load on the SWIS, even if the sum of the smaller loads on another transmission element create the largest risk (and determine the CRL requirement).

6.4 Review Outcomes – Contingency Reserve Lower Services

Revise the cost allocation method to:

- allocate CRL costs to Loads for consumption above 120 MW using the Runway Method;
- prorate CRL costs to Loads for consumption below 120 MW; and
- separately allocate facility and network risks.

7. Other Essential System Services

The method for allocating Rate of Change of Frequency (RoCoF) Control services was out of scope for the Cost Allocation Review. However, the Review considered the methods to allocate System Restart Service and NCESS.

The Consultation Paper made the following proposals:

Proposal 5 – System Restart Services

System Restart pricing is primarily focused on achieving cost recovery from beneficiaries, so the cost for System Restart Services should be borne by loads, as per the current practice.

Proposal 6 – NCESS

Recovery of NCESS should occur as follows:

- where AEMO procures the NCESS, the NCESS costs should be allocated to beneficiaries of the services (Market Customers), given that the current focus of NCESS charges is cost recovery and not market efficiency; and
- where Western Power procures the NCESS, these services are a substitute for network investments, so it is appropriate for Western Power to recover these costs via network access charges.

7.1 Key Issues Raised and EPWA Responses

Most CARWG members were supportive of maintaining the current approach to cost recovery for the System Restart Service and NCESS. However, some members wanted clarifications of current practices.

Synergy sought clarification on the cost recovery method for System Restart Services, which included:

(1) whether costs are recovered by a simple share of MWh, and

(2) the treatment of ESR.

The current practice is to recover System Restart costs from Market Participants based on electricity consumed by their customers at the node, consistent with beneficiary-pays principle.

Since a grid connected ESR is not a causer of the requirement for System Restart Services, nor a customer or beneficiary of this service, energy used by ESR should not be levied for System Restart Services. Ultimately, the energy stored by the ESR will be discharged for use by loads in the SWIS, and loads will pay for the System Restart Service costs.

In the case of a hybrid facility, which could contain a large load, ESR and onsite generation, total electricity consumed by the facility would be charged for System Restart Services. The electricity stored in the ESR may be used by the load at another time, to reduce, for example, the load’s Individual Reserve Capacity Requirement (IRCR). As the load is the beneficiary of the System Restart Service, allocating the cost of the System Restart Service on the hybrid facility is consistent with the beneficiary-pays principle.

The Australian Energy Council (AEC) wanted to understand whether penalties/refunds could be applied to a Facility that has a Forced Outage and is the 'causer' of the NCESS requirement. This issue has been addressed in the Reserve Capacity Mechanism Review.[16]

Synergy suggested that locational signals could be provided to Market Participants to minimise the requirement for NCESS. Synergy provided an example that:

> …if a Market Participant ignored locational investment signals before building a generator and this resulted in NCESS procurement, all NCESS costs should instead be allocated to that Participant.[17]

As indicated in the Consultation Paper, NCESS was only implemented recently and, based on the NCESS procurements already undertaken by AEMO, is likely to address various scenarios (e.g. Minimum Demand vs Peak Demand issues). Therefore, it is difficult to attribute costs for NCESS procured by AEMO to particular loads or Energy Producing Systems, at this stage.

It is also likely that future NCESS procurements undertaken by a Network Operator will be aimed at addressing locational issues. Costs for NCESS procured by Western Power will be recovered through network tariffs, which EPWA considers remains appropriate.

It should also be noted that Synergy's issue will be partially addressed by the proposal under the Reserve Capacity Mechanism Review to distribute capacity refunds to Market Participants that are responsible for Loads rather than to capacity providers.[18]

Therefore, the review outcome is that the allocation of NCESS costs should be reviewed again once the WEM has more experience with NCESS.

7.2 Review Outcomes for Other ESS

Retain the current cost recovery methods for System Restart Services and NCESS.

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16 Section 2.4.5 of the *Reserve Capacity Mechanism Review, Information Paper (Stage 1) and Consultation Paper (Stage 2)*, published on 3 May 2023, and available at https://www.wa.gov.au/system/files/2023-05/epwa_reserve_capacity_mechanism_review_information_and_consultation_paper.pdf.

17 Page 4 of Synergy's submission to Cost Allocation Review Consultation Paper (https://www.wa.gov.au/system/files/2023-02/Submission%20-%20Cost%20Allocation%20Review%20Consultation%20Paper%20-%20Synergy.pdf)

18 See Proposal S in the *Reserve Capacity Mechanism Review – Information Paper (Stage 1) and Consultation Paper (Stage 2)* at https://www.wa.gov.au/system/files/2023-05/epwa_reserve_capacity_mechanism_review_information_and_consultation_paper.pdf.

Appendix A. Summary of Submissions to the Consultation Paper and Responses to those Submissions

Participant	Issues	Response
Proposal (1)(a) Retain the current method for allocating Market Fees to Market Participants		
AEMO	Supports, but recommends reviewing at an appropriate time in the future.	
Alinta Energy	Broadly supports.	
AEC	Supports.	
Expert Consumer Panel (ECP)	Supports.	
Perth Energy	Supports.	
Shell Energy	Supports retaining the current fee allocation method, but notes that it is not necessarily the most fit for purpose.	
Synergy	Agrees, noting the limited efficiency benefits of implementing a new WEM Hybrid Method for allocating Market Fees. Notes that some Market Fees borne by Market Participants are due to non-Market Participant queries and that it may be relevant for AEMO to minimise these. If the WEM Hybrid Method is reviewed at a later stage, then use of customer's IRCR may not be a fair measure for allocating Market Fees.	

Participant	Issues	Response
Proposal (1)(b) Ignore recharge energy when allocating Market Fees to storage Facilities		
AEMO	Recommends that storage Facilities are charged on both withdrawal and injection, as this is the basis on which costs are incurred in managing the system and the market. Ignoring recharge when allocating Market Fees would result in associated costs being recovered from other Market Participants.	The Coordinator acknowledges and agrees with the range of issues raised by AEMO in both formal submissions and other correspondence. This proposal has been revised – see section 3 of this paper.
Alinta Energy	Broadly supports.	
AEC	Supports.	
Perth Energy	Agrees that storage Facilities should only be charged once but recharge energy is a more appropriate measure, as this is a fairer parallel to charging generators and loads on their gross usage.	
Shell Energy	Consider the implementation costs associated with suggested treatment of storage Facilities to ensure that there is a net benefit.	Proposal (1)(b) will not be implemented.
Synergy	Agrees in principle, but further consideration is needed as to how this will work for hybrid Facilities, and if the treatment for hybrids will differ depending on the Facility structure.	One of the rationales for withdrawing this proposal is that it would be difficult to apply to hybrid facilities. Separate metering of loads, generation and ESR that is behind-the-meter (BTM) may be required, at extra cost, and there could be incentives for hybrid facilities to minimise non-ESR consumption (not an efficient outcome).

Participant	Issues	Response
Proposal (2)(a) Adopt the WEM Deviation Method to allocate Regulation costs in 2024/25		
AEMO	The proposed method ignores forecasts for sent-out generation from Semi-Scheduled Facilities and instead apportions costs based on deviations from a hypothetical linear dispatch target. As a result, there is no incentive for Semi-Scheduled Facilities to meet their expected output, only to maintain a linear ramp to avoid Regulation costs. Where actual output deviates from expected output and a Semi-Scheduled Facility maintains a linear ramp, the Regulation service to meet the deviation would be distributed to other Facilities. Fails to provide incentives to minimise both volatility and forecasting accuracy. Recommends that forecasts be determined ex-ante.	The WEM Deviation Method has been amended to address the concerns raised by AEMO – see section 4 of this paper.
Alinta Energy	Concerned that the WEM Deviation Method and the new NEM Causer-Pays Method will both impose additional costs on large-scale renewable generators and will not address BTM PV customers' contribution to frequency deviations or deliver substantial benefits. Propose re-considering the current NEM forecasting method (AEMO responsible for central forecasting of intermittent generation with generators having the option to provide forecasts) because this may improve the forecast accuracy and minimise regulation requirements without imposing additional costs and may improve consistency (but note that Market Participants may not improve forecasting if their contracts allow them to pass through these costs).	The purpose of the WEM Deviation Method is to allocate costs to the facilities that cause frequency deviations due to deviations in their output or withdrawal. It is anticipated that Semi-Scheduled Facilities will be a significant contributor to these frequency deviations and should therefore be allocated a higher proportion of the Regulation costs. It is estimated that 50% of Regulation costs would be allocated to loads (via retailers and aggregators) under the WEM Deviation Method. If the retailer or aggregator has customers with PV in their retail portfolio that cause significant deviations in output, then retailers can pass these costs through to their customers. However, allocation of costs to retail customers is out of scope for the Cost Allocation Review.

Participant	Issues	Response
AEC	Avoid any approach that will impose additional costs on renewable projects. Payments from large-scale renewable projects should be proportional to the Regulation costs they cause and those caused by rooftop PV.	See the response to Alinta Energy's comments.
Perth Energy	Supports the WEM Deviation Method.	
Shell Energy	Supports the WEM Deviation Method.	
Synergy	Further investigation of the WEM Deviation Method and the new NEM Causer-Pays Method is required and there would be cost savings from implementing one method rather than implementing one and later replacing it with the other. Incentives are needed for normal loads (not aggregators) to operate BTM batteries in a way to minimise load variations – this will need to be done by regulated tariffs. Query whether using a linear dispatch target is appropriate for modelling, as ramping is not typically linear, and whether there are different targets for each 5-minute Dispatch Interval. Loads may not be able to be incentivised to minimise deviations in generation because they are subject to regulated tariffs due to the complexity involved with explaining this mechanism to retail customers.	The focus of the Cost Allocation Review is allocation of Regulation costs to Market Participants (not retail customers) to provide them incentives to reduce Regulation costs by minimising generation and load deviations. Incentives for improving the behaviour of retail customers to reduce wholesale costs is out of scope for the Cost Allocation Review. Measuring deviations from a linear dispatch target over five minutes is a standard approach in the NEM.

Participant	Issues	Response
(2)(b) Reassess the New NEM Causer-Pays method to allocate Regulation costs in 2027, for potential implementation in 2028/29		
AEMO	Supports	
Alinta Energy	Support conducting a cost-benefit analysis of the reforms, but it should not be required in 2027 – instead, EPWA should reserve the right to initiate a review at its discretion.	A high-level cost-benefit analysis of implementing a causer-pays method to allocate Regulation costs is provided in section 4.3.2 of this report.
AEC	Adopting the new NEM Causer-Pays Method should only take place if there is pressing need as it will divert limited resources and result in significant implementation costs.	See the response to Alinta Energy's comments.
Perth Energy	Supports, but if the new causer-pays method requires a significant rebalance in allocation of costs, consideration should be given to the appropriate timing for introduction.	Implementation of the WEM Deviation Method will be delayed until October 2025 to align with implementation of 5-minute settlement and to put less pressure on AEMO given the commencement of the new wholesale market arrangements on 1 October 2023.
Shell Energy	A cost-benefit analysis is required to inform the recommended method.	See the response to Alinta Energy's comments.
Synergy	Unable to consider the expected costs of implementation as a cost-benefit analysis has not yet been completed. Further investigation of the WEM Deviation Method and the new NEM Causer-Pays Method is required and there would be cost savings from implementing one method rather than implementing one and later replacing it with the other.	See the response to Alinta Energy's comments.

Participant	Issues	Response
Proposal (3) Where a Facility has multiple units with separate network connections, adjust the runway method for CRR so that each unit is treated separately		
AEMO	Supports the policy intent but further work is required on practical implementation, including how costs will be assigned for aggregations based on Facility risk and on defining how multiple aggregated assets with multiple different risk profiles will be treated.	EPWA will draft WEM Amending Rules to implement these changes, in consultation with AEMO and Western Power.
Alinta Energy	Broadly supports.	
ECP	Generally, supports. Suggest that the Facility Risk value to be used for allocating the costs should use the largest single credible contingency that could occur for a Facility, even for Facilities with multiple units and more than one network connection. It may be necessary for Western Power and the Facility owner to determine the largest credible contingency for a Facility in some instances.	
Perth Energy	Generally, supports but it is essential that AEMO ensure that there are no other points of common mode failure that could take all units off-line simultaneously	
Shell Energy	Does not support. Need to consider what behavioural change this will drive. Queried if modelling has been undertaken of Facilities with multiple connections to determine the risk value of such Facilities, as the risk value should not necessarily decrease due to multiple connections. Noted that: (a) if the proposal is simply an improvement on the existing method, then it is hard to build an argument against the	Individual dispatchable units at a site are highly unlikely to have a coincident Forced Outage unless they are connected to the network through a single connection that fails. If a facility has multiple connections and is configured in a way that allows the units to be dispatched independently, then the Facility Risk value should be calculated on the basis of the individual dispatchable units, not in aggregate for the Facility. Aggregating the individually dispatchable units will over-

Participant	Issues	Response
	concept of treating the output from separately connected units as two distinct contingencies; (b) there is no transparency as to how an assessment of Facilities' Risk value would be conducted; (c) the assessment of a Facilities' Risk value is likely to be subjective; and (d) the change is unlikely to result in a net-benefits to customers and the overall cost of Contingency Reserve is unlikely to change, so the implementation costs are unlikely to be recovered.	estimate the risks and over-recover Contingency Reserve Rise costs from that Facility.
Synergy	Supports the intent of this Proposal. AEMO should only apply this method for Facilities where units are truly operated independently of each other. Need to ensure that Facilities are given the right incentives to minimise power system risk, without incentivising the avoidance of costs via aggregating multiple units and benefitting from treatment as single units.	
Proposal (4) Apply a Modified Runway Method to Allocate CRL Costs		
AEMO	Agrees with the principle of the proposed approach, but is unclear on implementation, and would like to consult further on detailed design.	
Alinta Energy	Broadly supports.	
Neoen (verbal submission)	Concerned that the application of the modified Runway Method above 120 MW may create bias against ESR in the SWIS. ESR has a very low risk factor, and this must be considered.	The CARWG discussed options to address Neoen's concerns –see section 6 of this paper.

Participant	Issues	Response
Perth Energy	Supports.	
Synergy	Supports the approach. Notes that aggregating small loads may create inconsistencies in the allocation of costs to loads above/below 120MW. Supports adjusting the methodology to cater for future load contingencies exceeding 120 MW.	
Proposal (5) Retain the current System Restart cost allocation method		
AEMO	Supports	
Alinta Energy	Broadly supports.	
Perth Energy	Supports.	
Shell Energy	Supports	
Synergy	Not opposed to the proposal but seeks clarification on: • whether these costs will be recovered based on a simple share of MWh; and • the treatment of ESR.	A grid connected ESR does not cause the requirement for System Restart services and is not a consumer or beneficiary of the service and, so ESRs should not be charged for System Restart services.
Proposal (6) Retain the current NCESS cost allocation method		
AEMO	Agrees, noting it may be appropriate to revisit once there is sufficient operational experience with the framework.	
Alinta Energy	Broadly supports.	
ECP	Supports.	Incentives for Facilities to be available and minimise Forced Outages and, as a consequence, reduce the requirements

Participant	Issues	Response
	Want to understand if there is an opportunity to improve the NCESS and related processes by directing penalties/refunds for non-performance that results in additional capacity being required through NCESS (e.g., long duration Forced Outages and fuel supply problems) to partly fund the NCESS rather than continuing to levy penalties/refunds to other generators, which requires all of the additional costs of NCESS to be borne by loads (consumers).	for NCESS, have been addressed in the Reserve Capacity Mechanism Review.
Perth Energy	Supports, but would not support significant changes without sufficient time to notify customers.	No changes are proposed.
Shell Energy	Supports	
Synergy	Further consideration as to the causers of NCESS requirements may be warranted before this cost recovery method is implemented (e.g., if a Market Participant ignores locational investment signals before building a generator and this resulted in NCESS procurement, then all NCESS costs should be allocated to that Market Participant).	As outlined in the Consultation Paper, it is difficult to identify 'causers' of the requirements for NCESS, and as such, it is appropriate to recover costs from beneficiaries rather than providing price signals to reduce NCESS requirements.
Other Comments		
ECP	Generally supportive of the proposed directions on the Consultation Paper. Ensuring the costs are accurately calculated and attributed to the Market Participant (generator, retailer or other party) who is in the best position to manage those costs is a foundational principle for the ECP. Unlikely to support changes to methodologies unless it is clear that they will incentivise behaviour that will drive down costs and support system security and/or decarbonisation objectives.	

Participant	Issues	Response
	Keen to resolve these matters and direct resources to the highest priorities – those which go to retirement of the State's legacy fossil fuel generation.	
Perth Energy	Generally supportive but note the importance of costs being predictable. Market Participants should, as far as practical and efficient, pay costs and receive payments directly linked to their specific operations. Will large batteries require CRR to be sustained at close to current levels to cover a trip?	

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