Department of
Energy and Economic
Diversification

GOVERNMENT OF
WESTERN AUSTRALIA

Energy
Policy WA

Meeting Agenda

Meeting Title:	Market Advisory Committee (MAC)
Date:	Thursday 19 March 2026
Time:	1:30 PM – 3:30 PM
Location:	Online

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda • Conflicts of interest • Competition Law	Chair	Noting	1 min
2	Meeting Apologies/Attendance	Chair	Noting	1 min
3	Minutes of Meeting 2026_02_11	Chair	Noting	1 min
4	Action Items	Chair	Noting	2 min
5	Update on Working Groups			
	(a) AEMO Procedure Change Working Group	AEMO	Noting	2 min
	(b) AEMO Major Projects Working Group	AEMO	Verbal Update	2 min
	(c) Capability Class 2 Technologies Review	CC2TRWG Chair	Decision	45 min
6	Reserve Capacity Prices Paid to Existing and Committed Generators	Noel Schubert	Discussion	45 min
7	WEM Effectiveness Review – Progress Update	Chair/Secretariat	Discussion	15 min
8	Market Development Forward Work Program	Chair/Secretariat	Noting	2 min
9	Overview of Rule Change Proposals	Chair/Secretariat	Noting	1 min
10	General Business	Chair	Discussion	3 min

Please note, this meeting will be recorded.

Competition and Consumer Law Obligations

Members of the MAC (**Members**) note their obligations under the *Competition and Consumer Act 2010* (**CCA**).

If a Member has a concern regarding the competition law implications of any issue being discussed at any meeting, please bring the matter to the immediate attention of the Chairperson.

Part IV of the CCA (titled "Restrictive Trade Practices") contains several prohibitions (rules) targeting anti-competitive conduct. These include:

(a) **cartel conduct**: cartel conduct is an arrangement or understanding between competitors to fix prices; restrict the supply or acquisition of goods or services by parties to the arrangement; allocate customers or territories; and or rig bids.

(b) **concerted practices**: a concerted practice can be conceived of as involving cooperation between competitors which has the purpose, effect or likely effect of substantially lessening competition, in particular, sharing Competitively Sensitive Information with competitors such as future pricing intentions and this end:

- a concerted practice, according to the ACCC, involves a lower threshold between parties than a contract arrangement or understanding; and accordingly; and
- a forum like the MAC is capable being a place where such cooperation could occur.

(c) **anti-competitive contracts, arrangements understandings**: any contract, arrangement or understanding which has the purpose, effect or likely effect of substantially lessening competition.

(d) **anti-competitive conduct (market power)**: any conduct by a company with market power which has the purpose, effect or likely effect of substantially lessening competition.

(e) **collective boycotts**: where a group of competitors agree not to acquire goods or services from, or not to supply goods or services to, a business with whom the group is negotiating, unless the business accepts the terms and conditions offered by the group.

A contravention of the CCA could result in a significant fine (up to $500,000 for individuals and more than $10 million for companies). Cartel conduct may also result in criminal sanctions, including gaol terms for individuals.

Sensitive Information means and includes:

(a) commercially sensitive information belonging to a Member's organisation or business (in this document such bodies are referred to as an Industry Stakeholder); and

(b) information which, if disclosed, would breach an Industry Stakeholder's obligations of confidence to third parties, be against laws or regulations (including competition laws), would waive legal professional privilege, or cause unreasonable prejudice to the Coordinator of Energy or the State of Western Australia).

Guiding Principle – what not to discuss

In any circumstance in which Industry Stakeholders are or are likely to be in competition with one another a Member must not discuss or exchange with any of the other Members information that is not otherwise in the public domain about commercially sensitive matters, including without limitation the following:

(a) the rates or prices (including any discounts or rebates) for the goods produced or the services produced by the Industry Stakeholders that are paid by or offered to third parties;

(b) the confidential details regarding a customer or supplier of an Industry Stakeholder;

(c) any strategies employed by an Industry Stakeholder to further any business that is or is likely to be in competition with a business of another Industry Stakeholder, (including, without limitation, any strategy related to an Industry Stakeholder's approach to bilateral contracting or bidding in the energy or ancillary/essential system services markets);

(d) the prices paid or offered to be paid (including any aspects of a transaction) by an Industry Stakeholder to acquire goods or services from third parties; and

(e) the confidential particulars of a third party supplier of goods or services to an Industry Stakeholder, including any circumstances in which an Industry Stakeholder has refused to or would refuse to acquire goods or services from a third party supplier or class of third party supplier.

Compliance Procedures for Meetings

If any of the matters listed above is raised for discussion, or information is sought to be exchanged in relation to the matter, the relevant Member must object to the matter being discussed. If, despite the objection, discussion of the relevant matter continues, then the relevant Member should advise the Chairperson and cease participation in the meeting/discussion and the relevant events must be recorded in the minutes for the meeting, including the time at which the relevant Member ceased to participate.

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Agenda Item 4: MAC Action Items

Market Advisory Committee (MAC) Meeting 2026_03_19

Shaded	Shaded action items are actions that have been completed since the last MAC meeting. Updates from last MAC meeting provided for information in RED.
Unshaded	Unshaded action items are still being progressed.
Missing	Action items missing in sequence have been completed from previous meetings and subsequently removed from log.

Item	Action	Responsibility	Meeting Arising	Status
1/2026	AEMO to provide regular updates on proposals 4 and 5 from the Essential System Services (ESS) Framework Review. **Proposal 4:** AEMO to implement a monitoring program over a twelve-month period to track the amount of headroom and footroom available from unaccredited Facilities or non-dispatched FCESS Facilities to better quantify mandatory Primary Frequency Response (MPFR) availability to assess the level of Contingency Reserve Raise and Lower that could be provided from the inclusion of MPFR.	AEMO	2026_02_11	**Open** AEMO is assessing synthetic inertia under their Engineering Roadmap and Energy Policy WA (EPWA) will be reviewing the supplementary ESS mechanism to procure synthetic inertia. Following the publication of the ESS Information paper AEMO will provide regular updates to the MAC on proposals 4 and 5 from the ESS Framework Review. Proposals 4 and 5 from ESS Review will be retained in the action log for AEMO to provide regular updates.

Item	Action	Responsibility	Meeting Arising	Status
	Proposal 5: AEMO to assess the suitability of Synthetic Inertia (RCS) from Battery Energy Storage Systems (BESS) in complementing synchronous Inertia from rotating machines, and consider potential barriers and suitable incentivisation for grid-forming BESS to provide such services.			
2/2026	EPWA to provide links to the meeting papers and minutes from the first Capability Class 2 Technologies Review meeting held on 23 October 2025.	EPWA	2026_02_11	**Closed** Links to meeting papers and minutes from the Capability Class 2 Technologies Review Working Group emailed to the MAC on 5 March 2026.
3/2026	An update on the AEMO Allowable Revenue Framework rule change should be provided out of session.	EPWA	2026_02_11	**Closed** Following the close of stakeholder submissions on the Consultation Paper, EPWA has assessed the submissions and has made changes to the review outcomes in response to the submissions. EPWA has now also completed the drafting of the proposed Electricity System and Market Amending Rules and is currently progressing the drafting of the proposed Gas Services Information Amending Rules.
4/2026	MAC members to provide comments on the 11 February 2026 General Business Paper to the MAC Secretariat and all MAC members and for this feedback to be incorporated into an agenda	EPWA	2026_02_11	**Closed** See Agenda Item 6

Item	Action	Responsibility	Meeting Arising	Status
	paper for discussion at the 19 March 2026 MAC meeting.			
5/2026	MAC members to revisit the MAC schedule at the 18 June 2026 MAC meeting to decide whether an additional in person meeting will be held.	MAC members	2026_02_11	**Open**

MARKET ADVISORY COMMITTEE MEETING, 19 March 2026

FOR DISCUSSION

SUBJECT: UPDATE ON AEMO'S WEM PROCEDURES

AGENDA ITEM: 5(A)

1. PURPOSE

Provide a status update on the activities of the AEMO Procedure Change Working Group and AEMO Procedure Change Proposals.

2. AEMO PROCEDURE CHANGE WORKING GROUP (APCWG)

	Most recent meetings	**Next meeting**
Date	12 February 2026	26 February 2026
WEM Procedures for discussion at APCWG	• Credible Contingency Events (version 2) • Relevant Level Method • Frequency Co-optimised Essential System Services Accreditation	Reserve Capacity Security

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as of 6 March 2026. Changes since the previous MAC meeting are in red text. A procedure change is removed from this report after its commencement has been reported, or a decision has been taken not to proceed with a potential Procedure Change Proposal.

ID	Summary of changes	Status	Next steps	Indicative Date
Procedure Change Proposal AEPC_2025_13 Low Reserve Conditions	AEMO has commenced the Procedure Change Process to propose a new WEM Procedure: Low Reserve Conditions, required to be developed in accordance with the requirements of clause 3.17.11 of the ESM Rules. AEMO's proposed WEM Procedure documents: • the processes AEMO will follow to identify a potential Low Reserve Condition and make a Low Reserve Condition Declaration under the: ○ Medium Term (MT) PASA horizon ○ Short Term (ST) PASA horizon; or ○ Real Time Operations Horizon. • the levels at which AEMO would make a Low Reserve Condition Declaration, being: ○ LOR 1; ○ LOR 2; and ○ LOR 3. • the notification processes and timeframes AEMO will observe when making a Low Reserve Condition Declaration. • the process AEMO will follow to reassess a Low Reserve Condition associated with a Low Reserve Condition Declaration, made under the MT PASA or ST PASA, acknowledging increased uncertainty associated with longer-term forecasts.	Consultation closure	Commencement	March 2026

ID	Summary of changes	Status	Next steps	Indicative Date
	• the principles and processes associated with implementing an AEMO Intervention Event or actions required under clause 7.7.4 of the ESM Rules, to resolve a Low Reserve Condition.			

ID	Summary of changes	Status	Next steps	Indicative Date
Procedure Change Proposal AEPC_2025_20 Credible Contingency Events	AEMO has commenced the Procedure Change Process to propose amendments to the WEM Procedure: Credible Contingency Events and to implement the outcomes of Schedule 4 of the Wholesale Electricity Market Amendment (Miscellaneous Amendments No 3) Rules 2024. These Amending Rules insert additional requirements on AEMO to document the method and factors AEMO takes into account when determining Facility Raise Contingencies, Facility Raise Contingency Risks; and Single Facility Raise Risks. AEMO extended the consultation period for AEPC_2025_20 under section 2.10 of the ESM Rules and has published updated versions of the Procedure Change Proposal (version 2) and draft WEM Procedures (v3.2). The updated consultation documents were published on 20 January 2026.	Commenced	N/A	26 February 2026
Procedure Change Proposal AEPC_2026_01 Frequency Co-Optimised Essential System Services (FCESS) Accreditation	AEMO has commenced the Procedure Change Process to propose amendments to the WEM Procedure: Frequency Co-optimised Essential System Services Accreditation to: • amend the RoCoF Ride-Through Cost Recovery Limit; • require any amendments to the RoCoF Ride-Through Cost Recovery Limit be consulted on via the Procedure Change Process; and • allow for multiple Droop Settings for Facilities providing Contingency Reserve.	Commenced	N/A	26 February 2026

ID	Summary of changes	Status	Next steps	Indicative Date
Procedure Change Proposal AEPC_2026_02 Relevant Level Method	AEMO has commenced the Procedure Change Process to propose the new WEM Procedure: Relevant Level Method as a result of Amending Rule 4.11.2B, which commences on 1 April 2026. Amending Rule 4.11.2B requires that AEMO document in a WEM Procedure the assumptions and processes for the Relevant Level Method, including how AEMO determines: • the DER Adjusted Demand Profile under step B.2.2 of Appendix 9 of the ESM Rules; • the Reference Demand Profile under step B.2.5 of Appendix 9 of the ESM Rules; • Non-Candidate Availability Scenarios under step B.3.4 of Appendix 9 of the ESM Rules; and • any other aspect of the Relevant Level Method AEMO considers appropriate. This Procedure will impact on: • all Facilities that are assigned Certified Reserve Capacity using the Relevant Level Method, as the Procedure outlines the assumptions and processes for determining several inputs into the Relevant Level Method; and Non-Intermittent Generating Systems and relevant Electric Storage Resources that are “Non-Candidates”, as the Procedure specifies the means of determining the Non-Candidate Availability Scenarios. Non-Candidates include Non-Intermittent Generating Systems and certain Electric Storage Resources that have applied for Certified Reserve Capacity.	Out for consultation	Consultation Closure	9 March 2026

ID	Summary of changes	Status	Next steps	Indicative Date
Procedure Change Proposal AEPC_2026_03 Reserve Capacity Security	AEMO has commenced the Procedure Change Process to propose amendments to the WEM Procedure: Reserve Capacity Security to reflect various amendments that have been made to Reserve Capacity Security provisions of the ESM Rules. These amendments primarily originated from the Reserve Capacity Mechanism Review, including the requirements to provide replacement Reserve Capacity Security following a drawdown event, and changes to various defined terms. The amendments include: • Changing the term “DSM Reserve Capacity Security” to “DSP Reserve Capacity Security”. • Clarification of processes and documentation required for the provision of Security. • AEMO’s processes for transferring Security. • Clarification of eligibility and timing for returning Reserve Capacity Security. • The processes for releasing DSP Reserve Capacity Security.	Out for consultation	Consultation Closure	2 April 2026.

4. INDICATIVE SCHEDULE OF AEMO PROCEDURE CHANGE PROPOSALS

AEMO has prepared an indicative schedule of its Procedure Change Proposals expected to commence shortly. Changes since the previous MAC meeting are in red text. Procedure Change Proposals that have commenced since the previous MAC meeting have been moved from Table 4 into Table 3 above. While every effort has been made to ensure the quality of the information contained in the indicative schedule, the content (including timeframes) may be subject to change (e.g. due to availability of staffing resources, unforeseen competing priorities etc).

WEM Procedure	Summary of changes	Status	Next steps	Indicative date of next step
WEM Procedure: Facility Registration Processes	AEMO will be initiating this Procedure Change Proposal to accommodate changes resulting from WEM Reform and the Wholesale Electricity Market Amendment (Miscellaneous Amendments No. 3) Rules 2024.	Drafting in progress	Consultation	TBD
WEM Procedure: MT PASA	AEMO will be initiating this Procedure Change Proposal to update the WEM Procedure arising from WEM Reform. This WEM Procedure outlines the information AEMO requires and the process it will follow in conducting the Medium-Term Projected Assessment of System Adequacy.	Delayed	Consultation	TBD
WEM Procedure: Forecast Unscheduled Operational Demand	AEMO will be initiating this Procedure Change Proposal to accommodate the amendments to the ESM Rules from WEM Reform. This new WEM Procedure documents how AEMO will prepare the Forecast Unscheduled Operational Demand.	Drafting in progress	Consultation	March 2026
WEM Procedure: Settlements	AEMO will be initiating this Procedure Change Proposal to accommodate the amendments to the ESM Rules from Tranche 9 with changes to how AEMO distributes Civil Penalty Amounts.	Drafting in progress	Consultation	March 2026

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Agenda Item 5(c): Update on the Capability Class 2 Technologies Review

Market Advisory Committee (MAC) Meeting 2026_03_19

1. Purpose

The Chair of the Capability Class 2 Technologies Review Working Group (The Working Group) to provide an update on the Capability Class 2 Technologies Review (the Review).

2. Recommendation

That the MAC:

- notes the update provided in the paper; and
- provides views on the questions in the summary slides (Attachment 1).

3. Background

The Coordinator of Energy (Coordinator) must review several Electricity System and Market (ESM) Rules provisions related to energy and availability limited resources in accordance with section 4.13B of the ESM Rules. Under clause 4.13B.2 of the ESM Rules, the first review must be completed by 1 October 2026.

The MAC established a Working Group at the 24 July 2025 MAC meeting to support the Review.

The Terms of Refence, papers and minutes for the Working Group meetings are available on the relevant webpage. Further information on the Review, including the Scope of Works are available on the Review webpage.

4. Update

Demand Side Programmes Availability Intervals

The MAC its Working Group considered options for Demand Side Programmes (DSPs) availability intervals at the 11 February 2026 and 5 February 2026 meetings respectively. The preferred approach remains a split obligation window (Option 1) consisting of:

- 6am to 10am; and
- 2pm to 10pm.

During its discussions on 5 February 2026, members of the Working Group suggested that several variants of this option should also be assessed, including:

- an evening-only obligation window, to address concerns about DSP performance in the morning;
- aligning DSP and Electric Storage Resource (ESR) obligations, so both have morning and afternoon obligation duration and intervals; and

- dynamic obligation windows, set annually rather than fixed.

To finalise the discussion on 11 February 2026 MAC meeting, these variants have been further described and are summarised in Attachment 1. Additional refinements to Option 1 have also been proposed.

Due to their inferior rating against the criteria as well as the complexity of the implementation of the variants, it is recommended to progress Option 1 further in the Review.

The MAC's input is sought on the proposals.

Technical Analysis

AEMO has completed further analysis of the previously identified System Stress Events (SSEs). As a result, 13 events were removed because they resolved without intervention.

The 26 identified SSEs will form the basis for the further current-state analysis considerations by the Working Group and the development of policy options.

The Working Group will discuss stage 2 of the current-state analysis as well as future-sate analysis which is currently being conducted and make recommendations resulting from the analysis to the MAC.

The MAC is asked to note the stage 2 current-state analysis and provide input to help guide the Working Group's discussion.

5. Next Steps

The next Working Group meeting is currently scheduled for 26 March 2026.

6. Attachment

(1) Agenda Item 5(c) – Attachment 1 – Summary slides

Capability Class 2 Technologies Review

Context

Review empowered by ESM Rule 4.13B

Scope recap - Focus is on RCM settings relating to CC2 Technologies

- Higher penetration of weather dependent (intermittent) resources is making power system planning more uncertain and challenging – ESR is key to maintaining security and reliability
- Both ESR and DSPs are treated as duration/energy limited technologies in the ESM Rules:
    - Certification approach must reasonably estimate reliability impact
    - Availability obligations must be aligned to power system need and times when non-CC2 capacity is insufficient to meet demand

Scope item	Presented today?
Issue 1: Review whether current ESR certification methodology (Linearly De-rating Method) is still aligned with SEO.	✗ Presented Feb 2026
Issue 2: Review Reserve Capacity Refunds regime and evaluate potential to sharpen availability incentives	
Issue 3: Review DSP availability obligations against SEO (Update)	✓ Also presented Feb 2026
Technical Analysis – current-state analysis	✓
Technical Analysis – future state analysis	✗
Issue 4: Identify policy options to improve ESR availability (based on Technical Analysis)	✗
Issue 5: Assess whether existing Capability Class approach (under ESM Rule 4.5.12) is fit for purpose	✗

Policy options developed to be reviewed against SEO

SEO has three limbs: reliability, price and environment

- Different criteria developed for different policy issues
- Criteria are related to one or more SEO limbs and reflect potential market outcomes (which can affect the SEO adversely or beneficially or not at all)
- Policy options evaluated qualitatively and options measured based on how well criteria are met:

○	None of the criteria are met
◔	Some criteria met partially
◑	Some criteria met substantially or most met partially
◕	Most criteria met substantially
●	All criteria met substantially

See Appendix 1 for details on evaluation framework.

Criteria used to evaluate DSP Availability Options

Criteria	Map to SEO
Availability obligations are aligned with power system needs	Failing to make ESR/DSPs available during intervals of system stress will adversely affect the security & reliability limb
Availability obligations provide value for money	Diluted availability obligations for DSPs who receive the full Reserve Capacity Price for every MW of capacity would mean customers are paying the same amount for less reliability. This will adversely affect the pricing limb.
Availability obligations enable value to be extracted from BTM storage	Aligning DSP obligations to enable BTM batteries to charge during peak solar hours contributes positively to the environmental limb by more efficiently using stored renewable energy instead of curtailment.
Approach is flexible enough to change as power system needs evolve and change	Power system characteristics are evolving rapidly with more uncertainty due to the Energy Transition. Approaches to setting duration and availability obligations must be flexible enough to adapt to such changes so that the alignment with system need is maintained. Failure to do so would adversely affect the security & reliability limb
Approach is transparent and predictable	Opaque approaches to setting dynamic duration and availability obligations could deter DSP entry (and less efficient use of the BTM storage) if operators are unable to plan operations efficiently. This could adversely affect the security & reliability, pricing and environment limbs of the SEO.
Cost and complexity of implementation is reasonable	Costly implementation will add to market participant costs (through increased market fees) which adversely affects the pricing limb of the SEO

Issue 3: Demand Side Programmes

Review of availability obligation intervals

Issue 3: DSP availability obligation intervals

Policy problem definition recap

DSP availability period may not be sufficient to cover the evening peak

- 2025 WEM ESOO forecasted EUE occurring between 8 pm and 10:30 pm during 2025/26 Hot Season – DSP obligations end at 8pm.
    - AEMO indicated 50MW of Supplementary Capacity required
- Peak DSP Dispatch Requirement has decreased substantially to 23.75 hours (from 200 hours)
    - Requirement set to increase as more DSPs enter the market – however, expectation about repeated SC procurements may disincentivise DSP participation through RCM due to higher financial incentives in the former
- Review of DSP availability obligations needed to ensure these align with system need and that current settings do not result in increased non-market procurement

Residential Battery Scheme has resulted in large uptake of BTM batteries

- There is potential for these batteries to contribute to system reliability through RCM participation
- As batteries are duration limited (~30 kWh), they cannot meet the 12-hour requirement in ESMR 4.10.1(iii)
- Residential batteries can work in tandem with Industrial and Commercial BTM storage and loads within a DSP.

Issue 3: DSP availability obligation intervals - options

Recap of three main options presented to Working Group and MAC

Option	Description
Option 1: Split DSP availability into two blocks (Tranche 8)	DSPs must be available as follows: • Available between 6am – 10am and available to curtail up to 4 hours • Available between 2pm – 10pm and available to curtail up to 8 hours • DSPs have four-hour block to charge (10am – 2pm)
Option 2: Include DSPs in ESROD calculation	DSPs rolled into ESROD calculation: • AEMO calculates availability requirement based on which intervals have insufficient non-CC2 capacity to meet demand • No grandfathering for DSPs • DSPs must meet Peak DSP Dispatch Requirement
Option 3: DSP availability intervals based on Peak DSP dispatch requirement	DSP availability intervals determined annually by comparing the reference demand profile developed for CC3 ELCC calculations to the 50% POE/median growth load profile and identifying which Trading Intervals (or periods of time) DSPs should be available for.

DSP availability obligation intervals - options evaluation

Evaluation recap

- Option 1 performs best against SEO:
    - Retains 12-hour requirement
    - Simple to implement.
- Option 2 and 3 will dilute value provided by DSPs.
- Options 1, and 2 likely reduces the need for SC/NCESS procurement

Some variations to Option 1 were suggested and have been evaluated

	Option 1: Two availability blocks	Option 2: DSPs rolled into ESROD	Option 3: DSP availability based on Peak DSP Dispatch Req
Overall performance			
Availability obligations aligned with power system needs	Fully met (Only substantially met if allow to choose between split window or continuous 12-hour option)	Partially met	Not met
Availability obligations provide value for money	Fully met	Partially met	Not met
Availability obligations enable value to be extracted from BTM batteries	Fully met	Fully met	Fully met
Approach is flexible enough to change as power system needs evolve and change	Substantially met	Substantially met	Partially met
Approach is transparent and predictable	Fully met	Partially met	Partially met
Cost and complexity of implementation is reasonable	Fully met	Partially met	Partially met

See Appendix 1 for detailed evaluation

DSP availability obligation intervals options – Variant 1

Only an evening obligation window due to issues with performing during the morning obligation window

Due to issues with residential storage being available in the morning what if there was only an evening window (2pm-10pm)?

This would involve:

- Diluting existing availability obligations and require Capacity Credits to be derated to reflect this; or
- Reviewing the Peak DSP Dispatch Requirement to increase the annual availability requirements.
  Note: the Peak DSP Dispatch Requirement was extensively consulted during the RCM review
- Empowering AEMO to shift the DSP availability window if system conditions require it (similar to how ESROIs can be moved)
- Significant implementation complexity associated with this approach as fundamental approach to DSP pricing and Peak DSP Dispatch Requirement will need to change
- Finding alternative (likely costlier) options (NCESS or SRC) to meet capacity requirements during morning window.

Due to its complexity and the ability for an aggregator manage the two windows this option it is not recommended.

It is expected that portfolio management would help address the morning obligation window.

Portfolio management – achieve both windows

Residential, Commercial and Industrial loads can complement each other

- Residential storage face challenges to respond to morning events, but Commercial and Industrial loads can.
- It is the aggregator’s responsibility to recruit a diverse range of loads capable of capacity provision during both windows:
  - Aggregator could activate Commercial and/or Industrial loads for the morning window as these loads are more flexible;
  - Storage technology can be programmed to discharge at certain periods;
  - Afternoon/evening window could include a mix of loads that can include residential.

Question: Does MAC have any comments on Variant 1?

DSP availability obligation intervals options – Variant 2

Combine Options 1 and 2, so that both ESR and DSPs have a morning and afternoon ESROD and associated ESROIs

This option significantly alters ESR obligations and requirements.

It would require significant changes to the ESM Rules including:

- Implementing more than one Peak Demand Period to capture the morning and evening availability obligation intervals;
- Significantly changing the ESR capacity allocation approach; and
- Implementing new methodology to determine how the two window ESROD/DSPOD should be calculated.

It is likely only new ESR (and maybe DSP) would be subject to the new obligations requiring grandfathering.

Due to the complexity and impact to the WEM to implement this option, it is not recommended.

Question: Does MAC have any comments on variant 2?

DSP availability obligation intervals options – Variant 3

Dynamic obligation windows that are set annually

A mid-peak DSP Obligation Interval (DSPOI) in each window that would be set by AEMO in the Electricity Statement of Opportunities (ESOO).

This would require changes to the ESM Rules including:

- Create the mid-peak DSPOI and the ability for AEMO to set it annually;
- Implementing a transparent method to outline how AEMO determines the DSPOI;
- Creating and implementing the methodology for setting the DSPOIs; and
- Creating a method for how DSPOIs will interact with the ESROIs;

This option builds on the basic Option 1 which already has some challenges. This option would require additional analysis to overcome further challenges to implement it, and that level of analysis is outside the scope of this review.

Consequently, the recommendation is to proceed with the base Option 1, as it is simpler and allows further evaluation later to see whether enhancements are worthwhile.

Question: Does MAC have any comments on variant 3?

Technical Analysis

Current-State Analysis

Technical analysis is input to Issue 4

Analysis is ongoing to identify system conditions/triggers for mandating charge obligations

Issue 4 relates to identifying system conditions and triggers to mandate charge obligations so that ESRs enter their respective ESRODs with sufficient charge to deliver their RCOQ

Issue 5 relates to how Capability Class capacity requirements are determined and whether this will result in an appropriate mix of CC1/CC2/CC3 technologies (noting that ESR requires CC1 and CC3 technologies to charge).

Technical analysis will inform policy through:

1. Current state: When and why have historical system stress events occurred? What were the underlying conditions at the time?
2. Future state:
   - When will batteries be needed in the future to avoid unserved energy?
   - Will there be sufficient non-CC2 technologies to enable ESR to charge and meet the Planning Criterion?

The following slides are key observations from the current-state analysis (detail in appendix)

Questions for MAC

1. Does MAC have any comment on the scope of the Technical Analysis?

Analysis	Scope
Current state analysis	Focused on historical System Stress Events (SSE): 1. Stage 1: a) When do SSEs occur in terms of seasonality, time of day, type of day (business/non-business)? b) What are the contributing factors to system stress? 2. Stage 2: a) What are ESR charge levels like entering into SSEs? b) What factors cause ESRs to enter SSEs with low charge levels?
Future state analysis (Ongoing, to be presented in future)	9 year look-ahead: 1. When are batteries likely to be needed in the future to avoid unserved energy? 2. What are the drivers of unserved energy and needing batteries in the future? 3. Is there sufficient non-CC2 technology to enable ESR to charge

What is a System Stress Event (SSE)?

Market Advisories and manual constraints used to identify SSEs occurring between November 2023 and August 2025

- Market advisories containing Low Reserve Condition declarations used to identify SSEs
- Manual constraints applied by AEMO to capture additional events not captured by advisories
- SSE start time based on the start-time specified in the most recent advisory relating to that event (so that any changes in event timing can be picked up)
- SSE end time based on the end-time specified in the most recent advisory relating to that event
- AEMO reviewed the 39 previously identified SSEs and recommended removing 13 because they resolved on their own

Dataset	Includes	Excludes
Market advisories 25 SSEs identified	Energy & ancillary services shortfalls	• Non-shortfall events (transmission or comms events) • Minor manual constraints • Ramp rate or RRS shortfalls • Emergency of High-Risk Operating State advisories due to system instability • Network and infrastructure failures
Manual constraints 1 SSE identified	Non-network constraints applied outside the above SSE durations	• Constraints relating to above SSEs • Network constraints • RoCoF shortfalls • Muja 6 reserve mode

Note:
- SSE duration (end time -start time) doesn't necessarily reflect how long ESR would be required.
- Insufficient information to determine whether ESR was needed for the full length of each event

Stage 1: Current-state analysis

Recap of key observations

- **26 SSEs identified between November 2023 and August 2025**
- **SSEs are not a “Hot Season” only phenomena**
    - 16% of events occurred in shoulder and winter months (2 in winter and 2 in shoulder)
- **23 events (88% of total) were triggered by extreme temperatures**
    - Most of them (20) occurred in summer
    - Low wind availability also tends to occur in summer – combination of scheduled outages and extreme (hot) temperatures can cause system stress
- **Most events started before grandfathered ESROIs (5:30pm)**
    - 6-hour ESROD captures events better, but there were still 19 of 26 events that occurred prior to 4:30pm
- **Most events are 3-4 hours in duration**
    - Longer duration events possible but most likely to occur in summer
- **Average ESR fleet charge level >=70% for 83% of events**
    - Average fleet charge level<50% for 1 event only
    - Stage 2 examines SSEs where ESR have depleted charge prematurely

Stage 2: Current-State Technical Analysis

Summary

5 SSEs in which individual ESRs recorded charge levels below 50% at either event start or at ESROI start were identified for further analysis. It was observed:

- 4 had charge <50% at the event start. The other 1 started with >50% but dropped to <50% by ESROI start
- Low charge levels are likely related to changes in WEM Energy prices due to a clear indication of price response: when price increases, ESRs tend to discharge, and when price decreases, ESRs shift to charging
- Low charge levels do not appear to be related to FCESS dispatch

For all five SSEs, information available to EPWA suggests that the revenue earned from discharging earlier in the day exceeded the refund paid during ESROI:

- As a result, participants' energy revenues outweigh the cost of refunds during the ESROI
- This suggests that the refund mechanism on its own does not ensure that ESR participants enter the ESROI with a high state of charge

Question: Does MAC have any preliminary observations about the stage 2 analysis that the Working Group will discuss?

Technical Analysis - implications

Two key issues

Issue 1: Some SSEs start before the ESROIs even with the 6-hour ESROD

- AEMO is empowered to shift ESROIs on the day before the Trading Day.
  AEMO is investigating how this rule can be operationalised so that ESROIs can be shifted if SSE is expected

  Future state analysis will inform when ESR are likely to be needed as AEMO's model dispatches ESR to avoid unserved energy. If there is a credible trend of stress events starting earlier with risk of unserved energy, then modelling should result in ESR dispatch during these periods.

  Note, AEMO is currently investigating the rationale for shifting Peak ESROIs for the 2025-26 Capacity Year from 16:30 to 17:30 in light of Technical Analysis findings. See Amendment to the Mid-Peak ESROI for the 2025-26 Capacity Year dated 29 September 2025.

Questions:

1. **Does MAC agree with the characterisation above?**
2. **Does MAC agree that refund regime should remain unchanged with focus on identifying triggers for mandating SOC obligations and for the Working Group to consider an additional refund mechanism to incentivise compliance?**

Issue 2: The existing refund regime alone will not incentivise ESRs entering ESROIs with full charge as high energy prices earlier in the day result in revenue > refunds payable

- Changing the existing refund regime (e.g. by changing the Dynamic Refund Factor) affects all technologies (not just ESR)
  - Could result in offer price distortion as participants try to manage refund exposure
  - Could also result in refunds reaching annual cap quicker before Hot Season ends – no more incentive for ESRs to be available after this.
- Mandatory state of charge obligations is preferable**
  - Want compliance by design – Civil Penalty provisions may not be enough of a deterrent to noncompliance with new obligations
  - An option is to create an additional refund/penalty mechanism that only applies to ESRs if AEMO has invoked its power to mandate state of charge levels before entering the Peak ESROD.
  - Refund/penalty operates in addition to existing refund regime (which will remain unchanged).

***Triggers to be informed by future state analysis.*

Appendix 1

Detailed evaluation of original DSP availability options

DSP availability evaluation

Option 1: Split DSP availability into two blocks

DSPs are available as below

Availability Block 1	Charging block	Availability Block 2
6am -10am (curtail up to 4 hours)	10am – 2pm (4 hours)	2pm – 10pm (curtail up to 8 hours)

- 12 hour availability maintained across two blocks (4 + 8)
- Allows sufficient time to charge during peak solar hours
- Window covers late evening (addressing recent SC procurement concerns)
- DSPs must still be able to meet the Peak DSP Dispatch Requirement
- 6am availability requires BTM storage to be charged beforehand – could this be an issue?

Requires changes to how Relevant Demand/settlement calculations are done to ensure DSPs with over-subscribed loads are not disadvantaged due to the behaviour of Associated Loads that are not activated during a particular event – covered in further detail later.

Criteria	Draft evaluation
Availability obligations aligned with power system needs	DSP dispatch and spare capacity levels indicate that split windows are aligned with times of system stress. Current 8am – 8pm window does not include the early morning, or late evening events and fails to recognise that additional capacity is unnecessary during the middle of the day. *Criteria met fully (only substantially if allowed to choose between split window or continuous 12-hour option)*
Availability obligations provide value for money	DSPs selecting split window option must still curtail for a max of 12 hours per day. Availability obligations are not diluted. Requires DSPs to be available after 8pm, thereby reducing likelihood of costlier SC or NCESS procurement *Criteria met fully*
Availability obligations enable value to be extracted from BTM batteries	Option enables BTM batteries to charge in the middle of the day during peak solar output, thereby using renewable energy instead of curtailing it *Criteria met fully*
Approach is flexible enough to change as power system needs evolve and change	The split availability blocks are static, but span a large enough window likely to capture system stress events. The single block does not capture early morning or late evening peaks. *Criteria met substantially*
Approach is transparent and predictable	The availability blocks are static so participants will know ahead of time when they will be needed *Criteria met fully*
Cost and complexity of implementation is reasonable	Simple to implement and will only require minor rule, process and system changes. *Criteria met fully*
Overall Performance	***All criteria met substantially***

DSP availability evaluation

Option 2: Include DSPs in ESROD calcs

- DSP availability intervals are dynamic and rolled into the ESROD calculations
- Appendix 11 updated to calculate ADG and ESROD by assessing whether there is sufficient non-CC2 capacity during Peak Demand Period.
- DSPs not grandfathered (unlike ESR)
- Will result in lower availability requirement:
  - 2027-28 ESROD of 6 hours would halve the existing 12 hour requirement
  - ESRs have lower requirement but must be available for all ESROIs during the year
  - DSPs only must be available to meet the Peak DSP Dispatch Requirement (23.75 hours in 2027-28)
- In theory, this option could be implemented with DSPs assessed under ELCC – more complex implementation and may stall DSP entry into RCM

Criteria	Draft evaluation
Availability obligations aligned with power system needs	Approach identifies Trading Intervals where non-CC2 capacity <= demand during peak demand period. Given ESROIs cover late afternoon to evening, DSPs will not be available for winter morning peaks. *Criteria met partially*
Availability obligations provide value for money	ESR & DSPs get same duration requirement, likely less than the 12-hour requirement. ESRs must be available throughout the year but DSPs must only meet Peak DSP Dispatch Requirement. Hence consumers will pay the same for less. Option performs better if DSPs assessed under ELCC per US markets. DSPs will be available after 8pm thereby reducing likelihood of costlier SC or NCESS procurement *Criteria met partially*
Availability obligations enable value to be extracted from BTM batteries	See Option 1. ESROD starts after peak solar hours enabling batteries to charge. *Criteria met fully*
Approach is flexible enough to change as power system needs evolve and change	Availability obligations change annually based on AEMO’s reliability modelling more accurately reflecting when CC2 technologies are likely to be required *Criteria met substantially*
Approach is transparent and predictable	Some uncertainty in availability requirements. Previous ESROD should give participants a starting off point for how long they may be required for. *Criteria met partially*
Cost and complexity of implementation is reasonable	Moderate changes to rules, processes and systems to incorporate DSPs into Appendix 11. *Criteria met partially*
Overall Performance	***Some criteria met partially***

DSP availability evaluation

Option 3: Calculate DSP availability requirements based on Peak DSP dispatch requirement

- DSP availability is dynamic and based on Peak DSP Dispatch Requirement.
- AEMO models which Trading Intervals the demand in the reference demand profile (used in ELCC calculations) is likely to be greater than the peak demand under a 50% POE peak/median growth scenario (adjusted for DSP dispatch and capacity). For example, winter mornings from 6am-9am and Hot Season from 3pm – 9pm.
- May result in smaller availability period than ESROD:
  - Could span smaller range of Trading Intervals than ESROD thereby diluting availability obligations further
  - Peak DSP Dispatch Requirement is 47.5 Trading Intervals for 2027-28.
- Similar approach is used in some US capacity markets, but these markets use ELCC to assign capacity to demand-side.

Criteria	Draft evaluation
Availability obligations aligned with power system needs	Approach incorrectly assumes DSPs only needed if reference demand profile peak > 50% POE peak (vs modelling ability of CC2 & non-CC2 capacity to meet peak demand). Unclear whether DSPs would be required to be available after 8pm as modelling is needed to assess which Trading Intervals are forecast to have demand greater than the 50% POE peak. *Criteria not met*
Availability obligations provide value for money	DSP availability obligations are likely to be significantly diluted under this approach – to make this option perform better, DSPs would need to be assessed under an ELCC like approach (per US capacity markets). Unclear whether DSPs would be required to be available after 8pm as modelling is needed to assess which Trading Intervals are forecast to have demand greater than the 50% POE peak *Criteria not met*
Availability obligations enable value to be extracted from BTM batteries	See Option 1. Peak solar hours unlikely to be included in Peak DSP dispatch requirement *Criteria met fully*
Approach is flexible enough to change as power system needs evolve and change	Availability obligations will change annually reflecting changes in demand shape and level of DSP participation. However, it will not pick up changes due to changing generation patterns. *Criteria met partially*
Approach is transparent and predictable	See Option 2 *Criteria met partially*
Cost and complexity of implementation is reasonable	Moderate changes to rules, processes and systems to incorporate DSPs into Appendix 11. *Criteria met partially*
Overall Performance	***Some criteria met partially***

Appendix 2

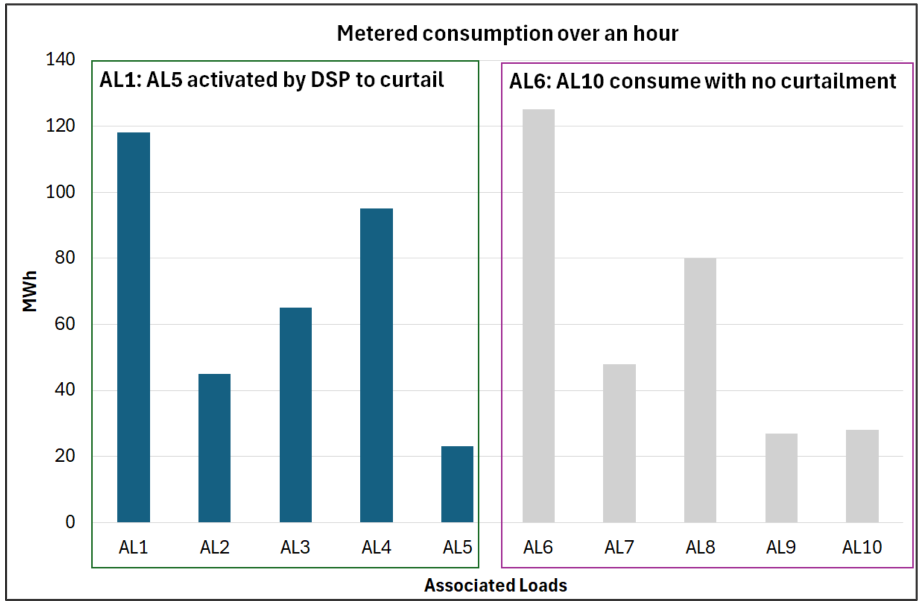
Rule changes needed to implement DSP availability Option 1

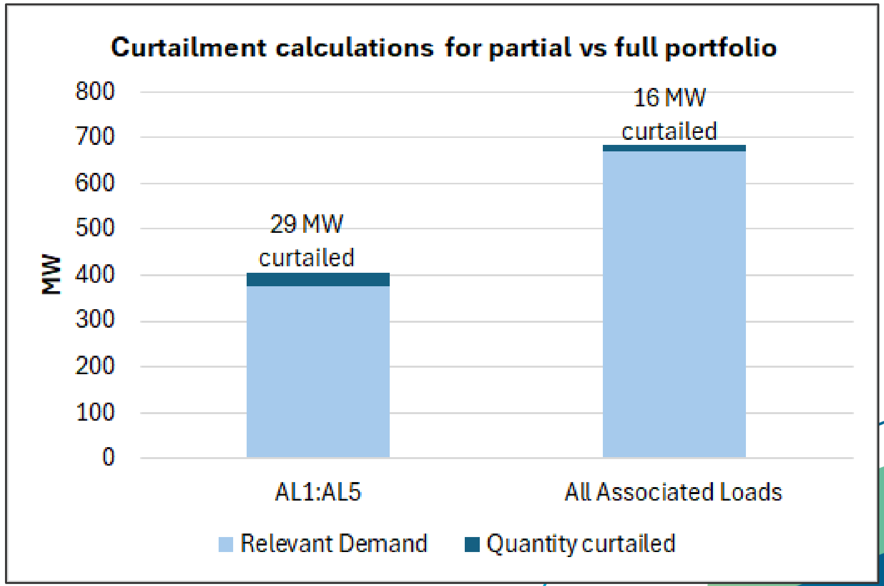
Changes to RCM settlement rules

Under Option 1, oversubscribed DSPs will be at a disadvantage if unused loads over-consume during a DSP dispatch event

Example

- DSP with 10 Associated Loads has been assigned 25MW of Peak Capacity Credits (RCOQ = 25MW).
- DSP has over-subscribed, so that it only needs to activate part of its portfolio to meet its delivery obligations.
- During a DSP Dispatch Event, the DSP activates five of its Associated Loads to provide a response of 25MW
    - Remaining loads can do as they please.
- During settlement, compliance with RCOQ depends on whether only activated loads are included in Relevant Demand calculation or whether the entire portfolio is included – unused loads can end up cannibalising the response of other loads in the portfolio.





Changes to RCM settlement rules

Under Option 1, oversubscribed DSPs will be at a disadvantage if unused loads over-consume during a DSP dispatch event

Amendments needed so that over-subscribed DSPs can specify which Associated Loads will be activated for a DSP Dispatch Event (and for Reserve Capacity Tests)

Specification of activated loads must occur ex-ante: For DSP dispatch event, need to strike balance between providing participant sufficient time to select loads to activate with mitigating any opportunity to game the baseline

- New Relevant Demand method uses most recent 10/50 or 5/50 non-DSP dispatch event days respectively for BD and NBD baselines
- Specifying loads within this window (~2 weeks of event) could result in participants gaming baseline
- Could require DSPs to associate/nominate loads for potential events at least 3 weeks ahead of time:
    - DSPs associate all subscribed loads but nominate activation status of each load to indicate whether load will be activated in the morning, evening or both
    - Proposed activation date must be at least three weeks in the future
    - Enables DSPs to specify different loads for morning vs evening activations.
    - Are restrictions needed on how frequently the activation status can be changed?
    - How would the above changes interact with the existing Reserve Capacity Testing process?

Changes to RCM settlement rules

Under Option 1, oversubscribed DSPs will be at a disadvantage if unused loads over-consume during a DSP dispatch event

Rule and system changes will be needed:

AEMO requires identification of which loads to include in Relevant Demand calculation:

- Amendments to existing load association/disassociation rules
- Appendix 9 (Relevant Demand) will require changes to ensure Relevant Demand is calculated over activated Associated Loads only
- Peak Capacity Shortfall (ESMR 4.26.2D) and related rules must be amended to measure response over activated loads only
- System changes needed to implement new association/nomination and settlement rules.

Timing of changes

- Above changes should occur at the same time that new Relevant Demand methodology and Misc 3 changes are implemented.

Appendix 3

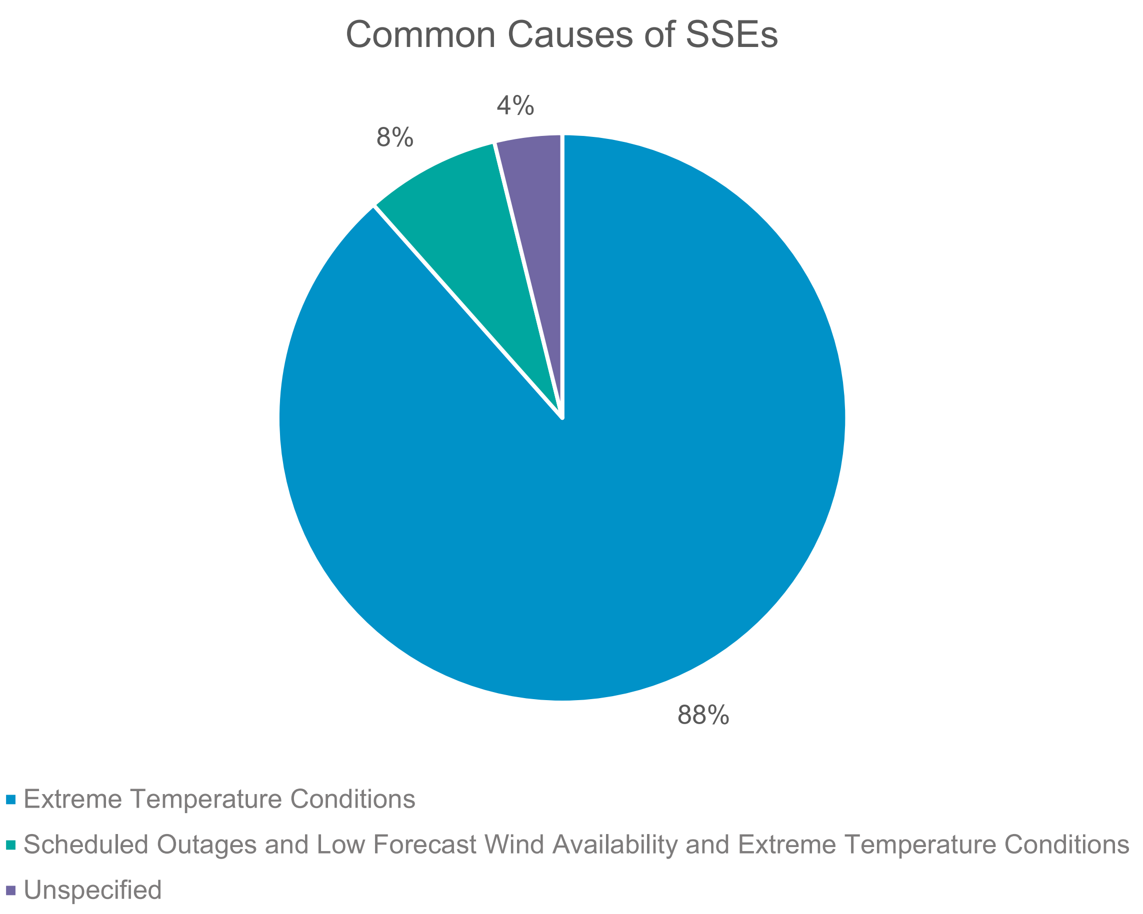
Stage 1: Current-State Technical Analysis - Detail

Historical System Stress Events (SSEs)

During the CC2 Current State Technical Analysis we have identified 26 historical SSEs

This pie chart shows the percentage breakdown of the main causes of the 26 identified SSEs:

- 88% were driven by extreme temperature conditions (both high and low).
    - 20 events occurred in summer, 2 in the shoulder season, and 1 in winter (the 25 August 2025 event)
- 8% were driven by a combination of scheduled outages, low forecast wind availability, and extreme temperature conditions
    - 2 events, and **only** occurred **in summer**.
- The remaining 4% of events were classified as unspecified (1 event)

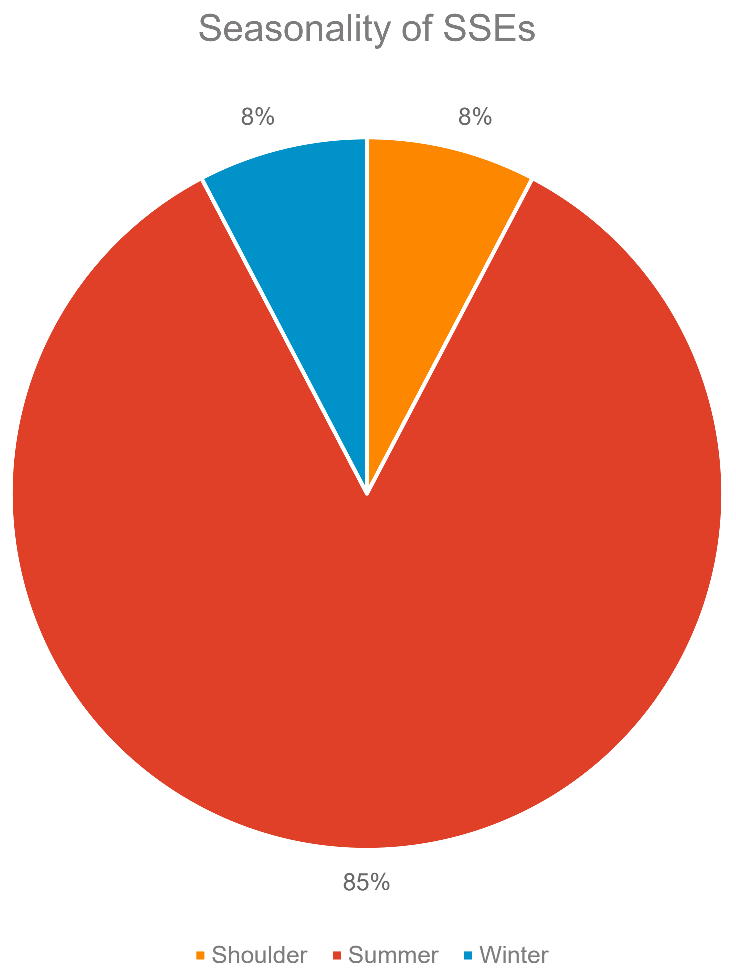


Historical System Stress Events (SSEs)

Seasonality of SSEs

This pie chart shows the percentage breakdown of the seasonality of the 26 identified SSEs:

- 85% of the SSEs (22 SSEs) occurred in summer (December – March)
- 8% of the SSEs (2 SSEs) occurred in the shoulder season (April, May, September)
- 8% of the SSEs (2 SSEs) occurred in winter (June – August)

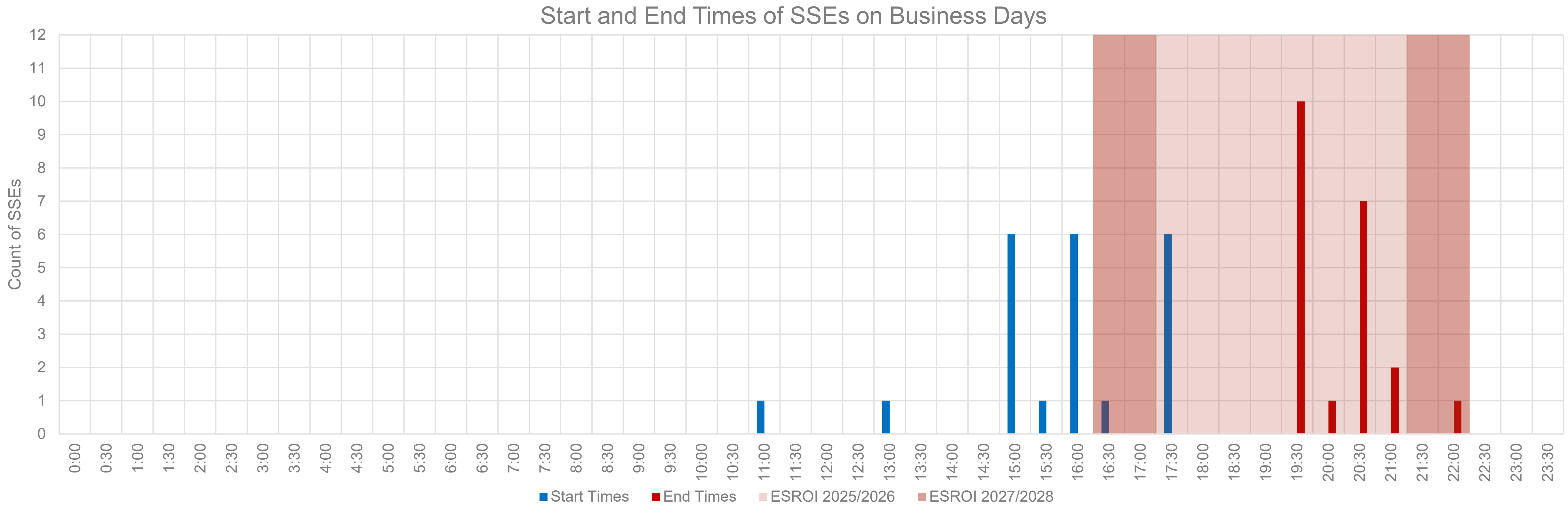


Historical System Stress Events (SSEs)

Timing of SSEs on Business Days

This chart shows the number of SSEs on business days by trading interval, comparing their start and end times with the current 2025-2026 ESROI and the future 2027-2028 ESROIs.

73% of business day SSEs started before the 2025-2026 ESROI, while 68% started before the 2027-2028 ESROI

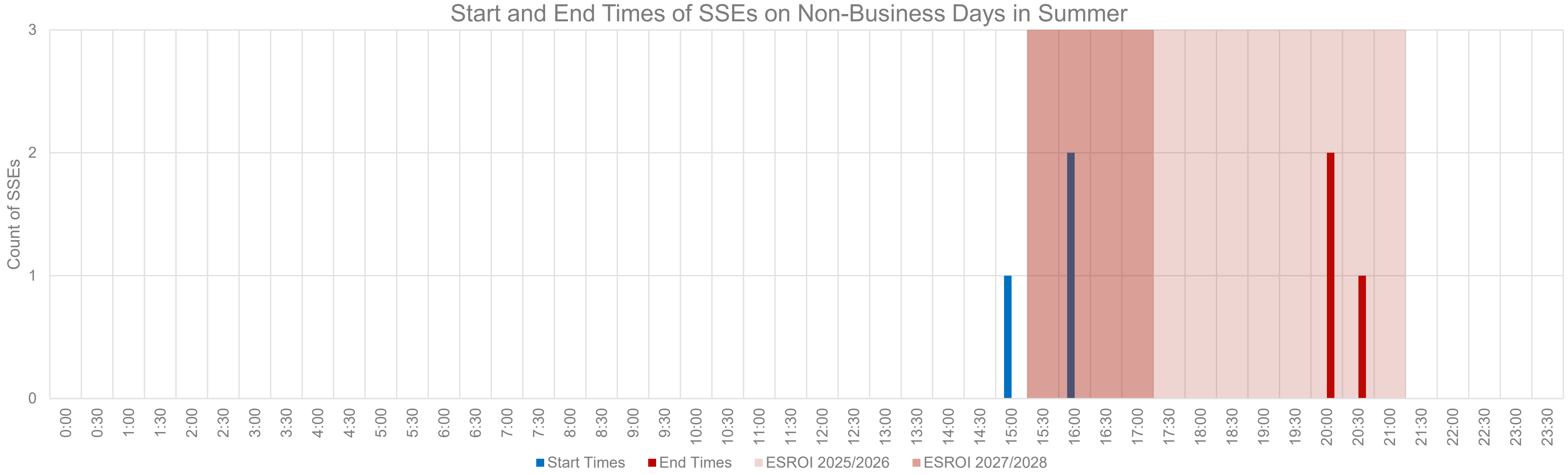


Historical System Stress Events (SSEs)

Timing of SSEs on Non-Business Days in Summer (Dec – Mar)

This chart shows the number of SSEs on non-business days in summer by trading interval, comparing their start and end times with the current 2025-2026 ESROI and the future 2027-2028 ESROIs.

All non-business summer SSEs started before the 2025-2026 ESROI, while one started before the 2027-2028 ESROI. Note that there were no SSEs that occurred both on non-business days and shoulder season.

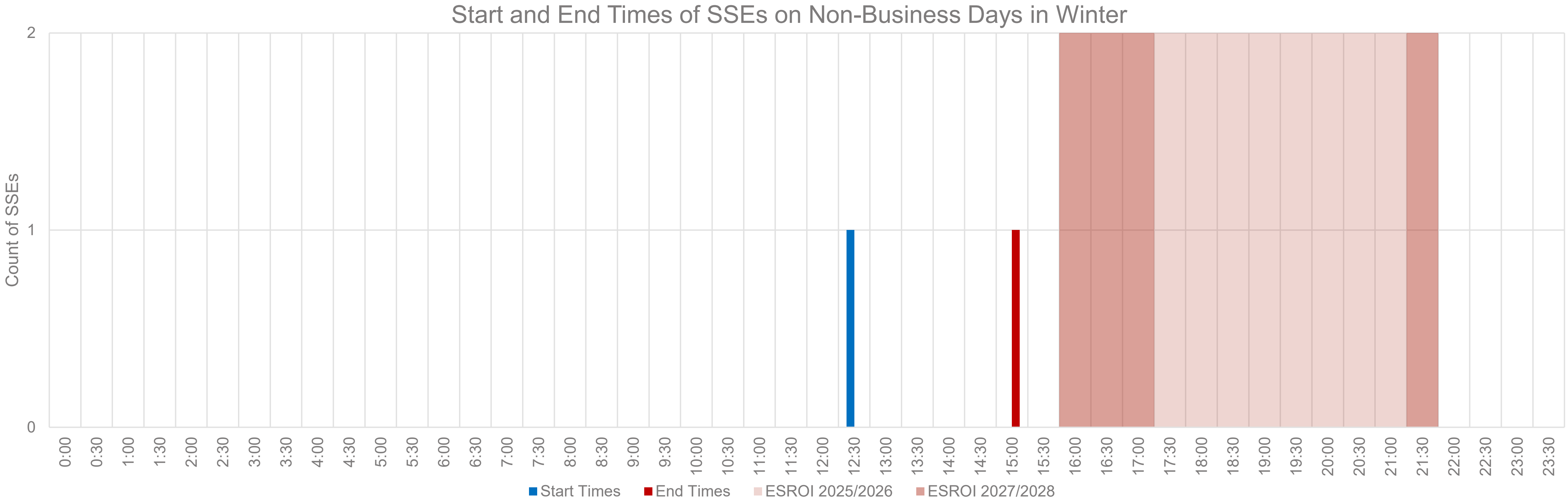


Historical System Stress Events (SSEs)

Timing of SSEs on Non-Business Days in Winter (Jun-Aug)

This chart shows the number of SSEs on non-business days in winter by trading interval, comparing their start and end times with the current 2025-2026 ESROI and the future 2027-2028 ESROIs.

The only non-business winter SSE started before both the 2025-2026 ESROI and the 2027-2028 ESROI.



Historical System Stress Events (SSEs)

SSEs Starting Before the 2025-2026 ESROIs

20 of the 26 historical SSEs identified started before the 2025-2026 ESROIs.

Common Characteristics of these 20 SSEs:

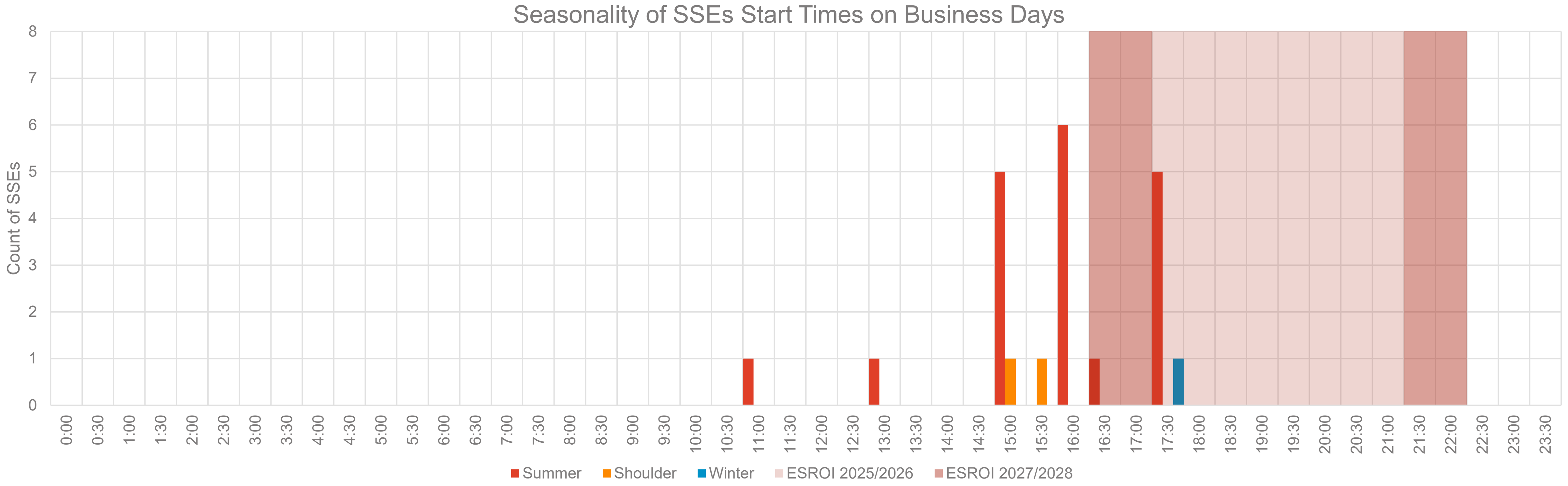
- **Timing:** The median start and end times were 15:15 and 20:30, with a median duration of 4.75 hours
- **Seasonality:** 17 events occurred in summer, 2 in the shoulder season and 1 in winter
- **Drivers:** Summer events were predominantly driven by heatwaves or higher than forecast temperatures
- **Severity:** Predominantly LOR1 or LOR2, with one event initially LOR2 and later upgraded to LOR3, and one event initially LOR1 and later upgraded to LOR2
- **Alignment with ESROIs:** Only one event extended beyond the end of the 2025-2026 ESROI
- **Day of the week:** Only 4 events were on Non-Business Days
- **ESRs Charge Levels:** The median charge level at event start was 79.5%

Historical System Stress Events (SSEs)

Seasonality of SSEs Start Times on Business Days

This chart shows the number of SSEs on business days by trading interval in the summer, shoulder, and winter seasons, comparing their start times with the current 2025-2026 ESROI and the future 2027-2028 ESROIs.

As shown in the chart, SSEs tend to start earlier in summer and shoulder seasons.

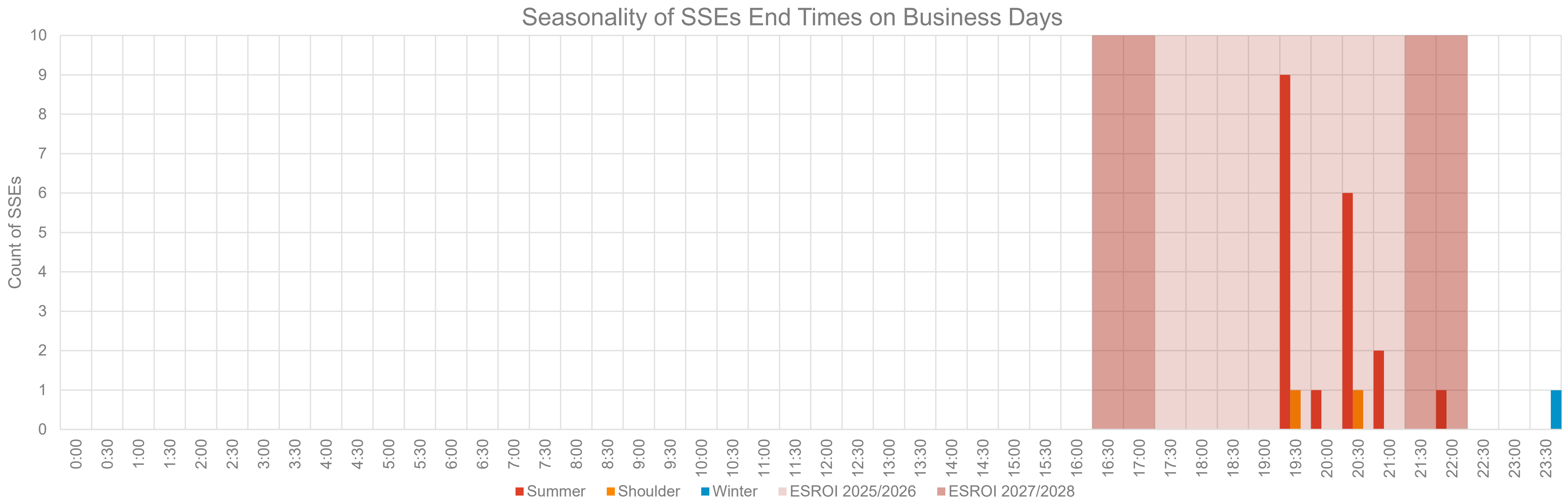


Historical System Stress Events (SSEs)

Seasonality of SSEs End Times on Business Days

This chart shows the number of SSEs on business days by trading interval in the summer, shoulder, and winter seasons, comparing their end times with the current 2025-2026 ESROI and the future 2027-2028 ESROIs.

As shown in the chart, only two SSEs ended after the 2025-2026 ESROI, one of which (the 25 August 2025 event) ended after the 2027-2028 ESROI as well.



Historical System Stress Event (SSEs)

Duration of SSEs by Season

The graph shows a scatter plot of SSEs durations across summer, shoulder and winter.

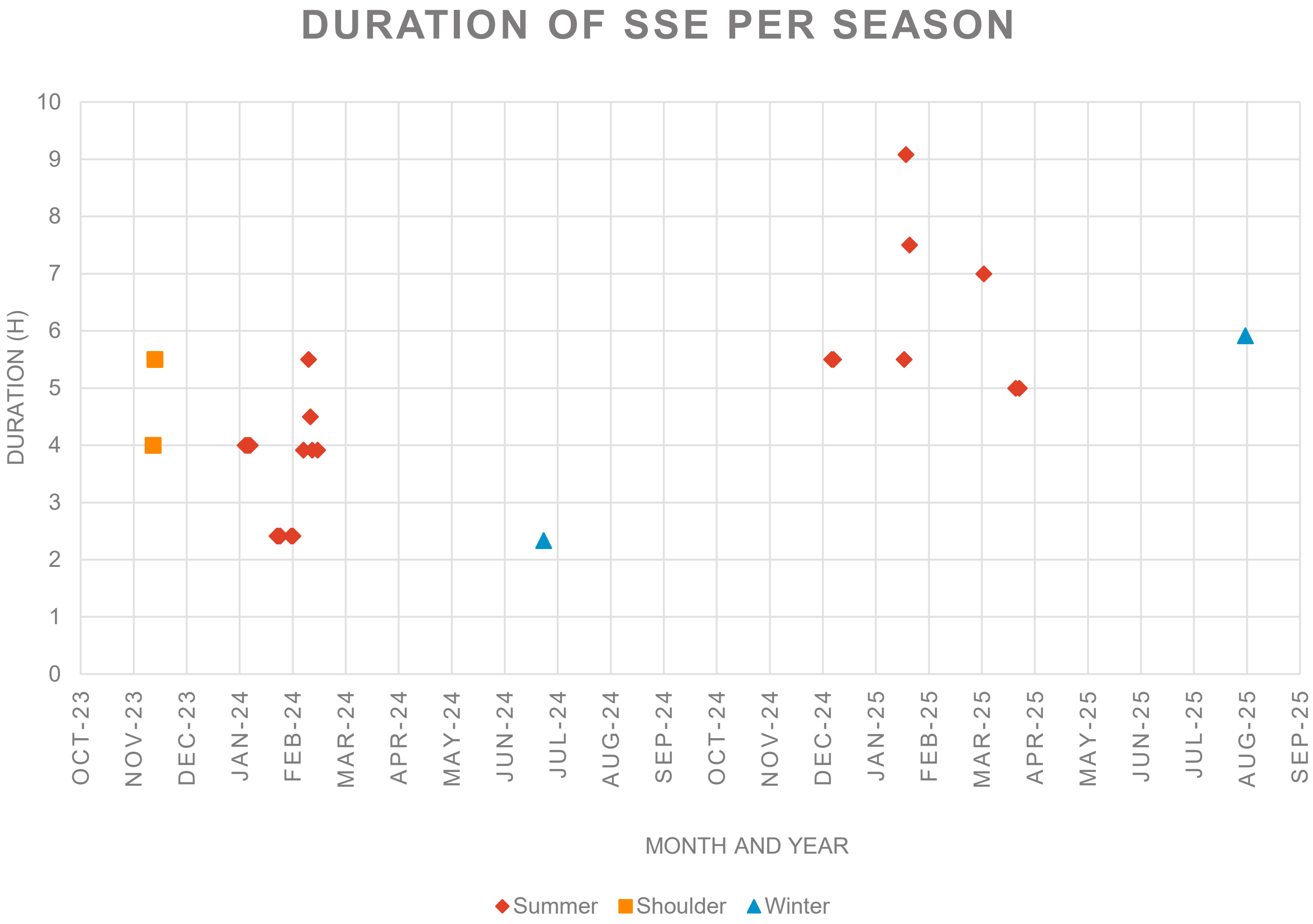
The three SSEs that had a duration greater than 6h occurred on:

- 21/01/2025 from 11:25 to 20:30
- 23/01/2025 from 13:00 to 20:30
- 6/03/2025 from 15:00 to 22:00

These SSEs had the following in common:

- They all occurred in Summer
- They started before the start of both the 2025-2026 ESROI and 2027-2028 ESROI
- They occurred on Business Days
- The 21/01/2025 and 6/03/2025 event had an average ESR charge level of 82% and 86% respectively, while the 23/01/2025 event had 54%.

As previously noted, SSE duration does <u>not</u> necessarily reflect durational requirement for ESR.

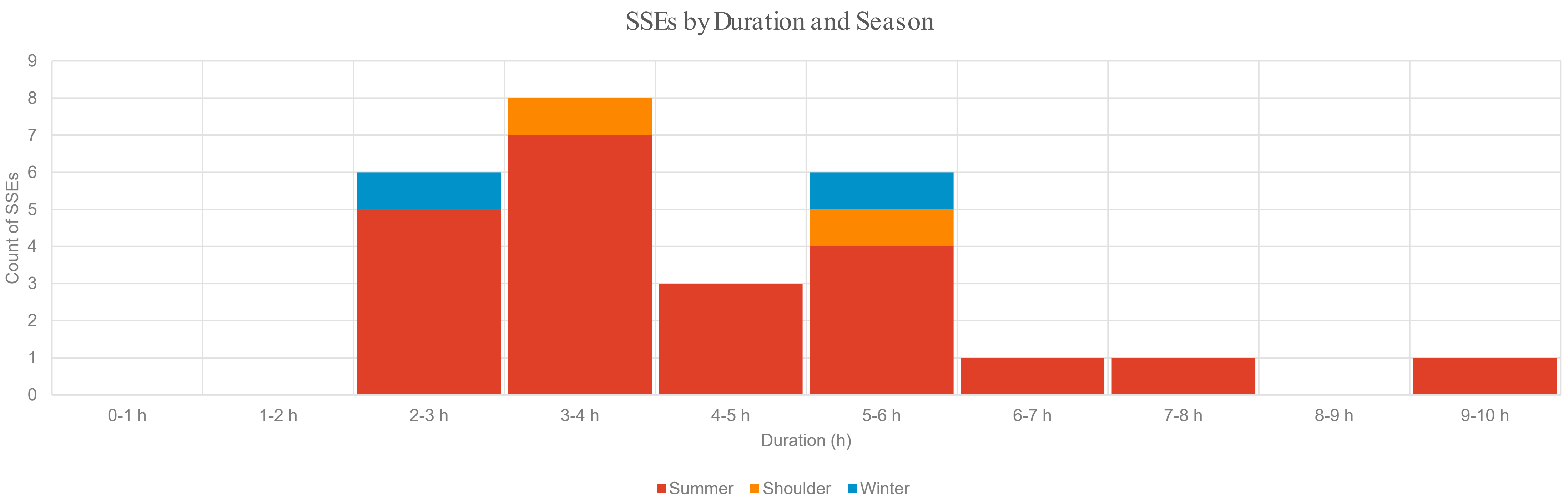


Historical System Stress Events (SSEs)

Number of SSEs by Duration and Season

This chart shows the number of SSEs by duration across summer, shoulder and winter.

- The chart indicates that SSEs most frequently have durations between 3 and 4 hours.
- Events in summer tend to have a greater duration than in winter and shoulder seasons.



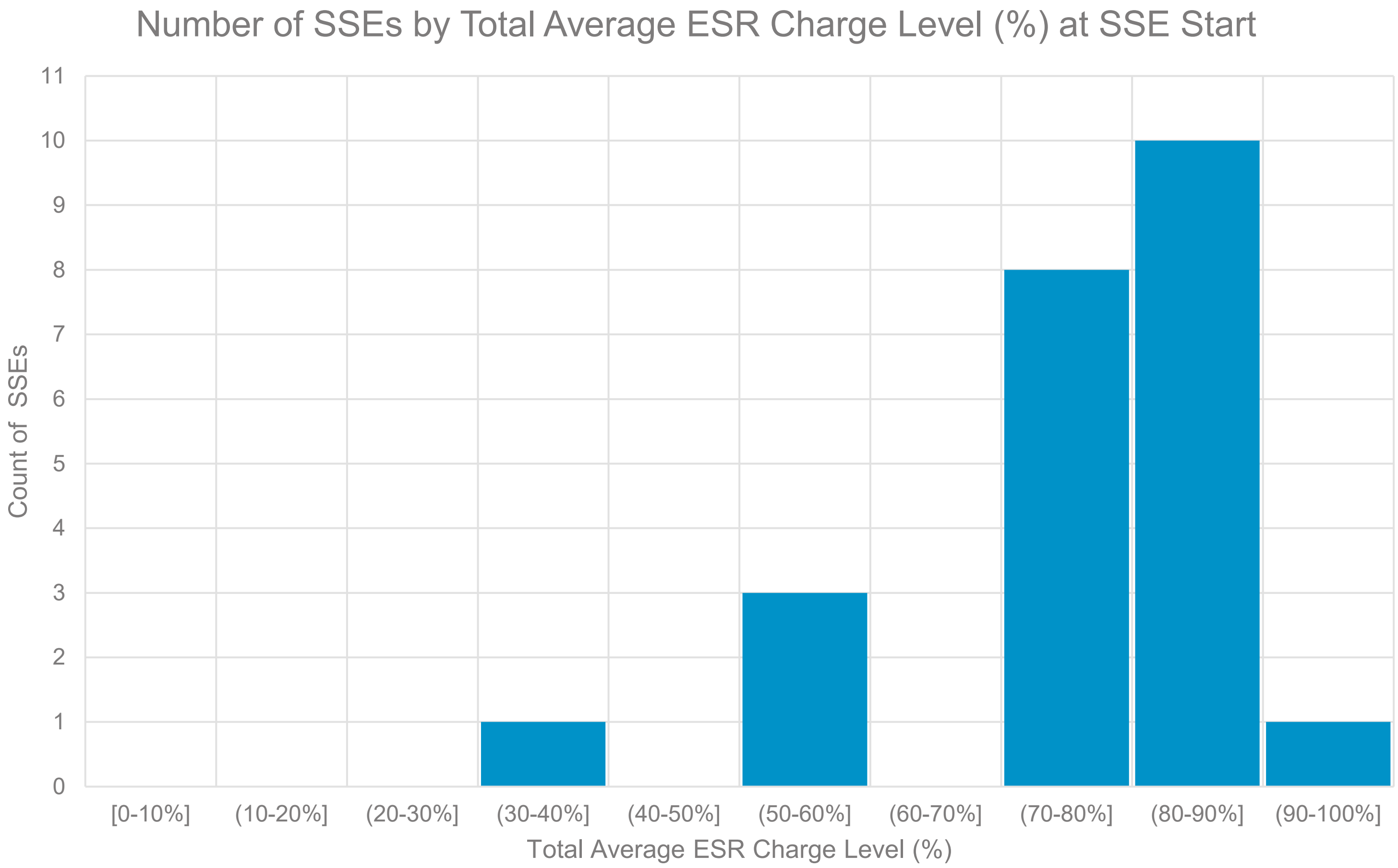
Historical System Stress Events (SSEs)

Number of SSEs by Average ESR Fleet Charge Level (%)*

This chart shows the number of SSEs by the average charge level (%) of the entire ESR fleet at the event start.

- 83% of SSEs had an average ESR charge level >= 70%
- ESRs on outage (forced or planned) excluded from charge level calculation

*Sourced from SCADA Case data.

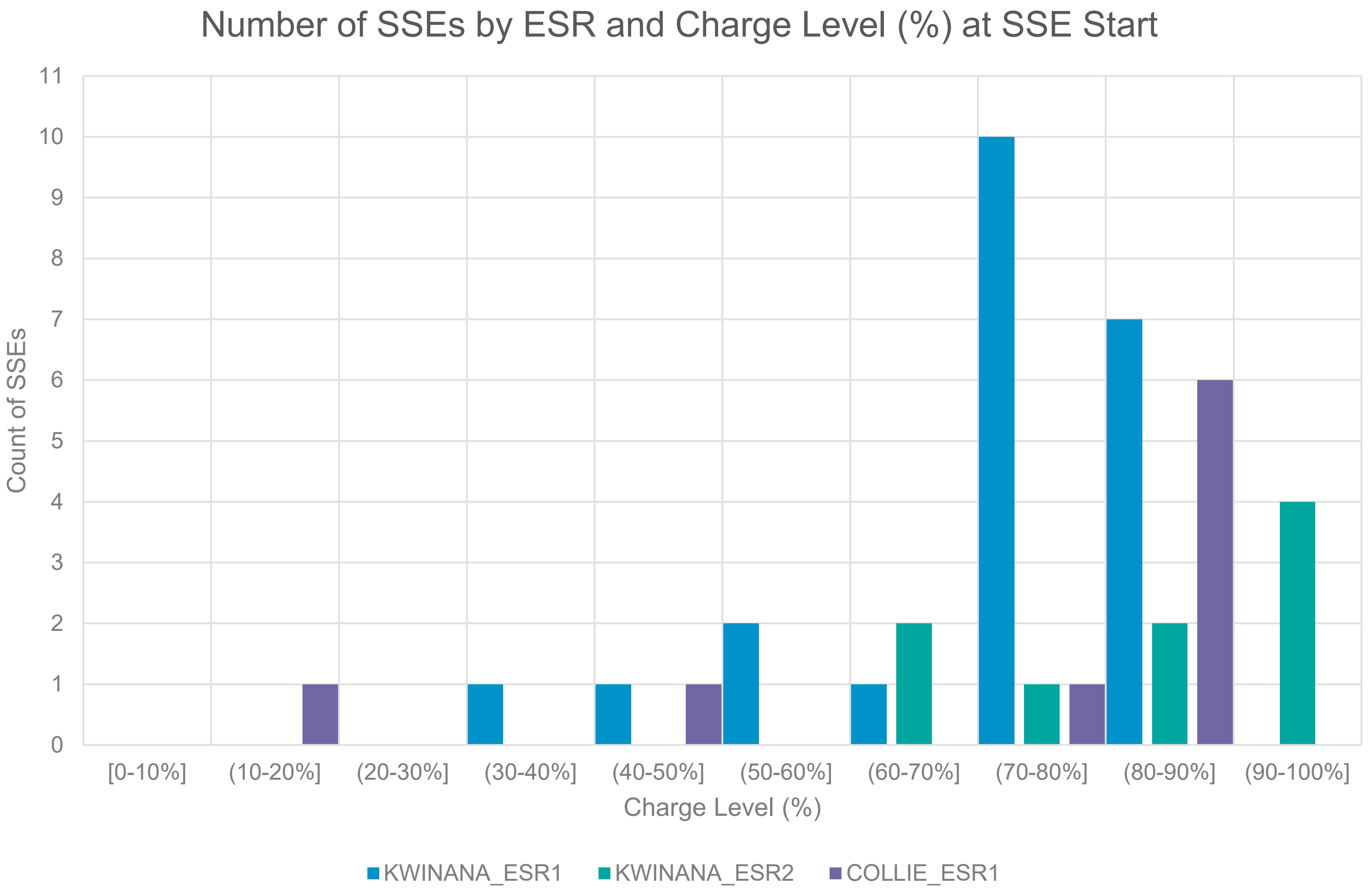


Historical System Stress Events (SSEs)

Number of SSEs by Average ESR Charge Level (%) of each ESR

This chart shows the number of SSEs by the average charge level (%) of each ESR at event start.

- COLLIE_ESR1 had charge levels of 80-90% for 67% of the events
- KWINANA_ESR2 maintained a minimum charge level of 64% across all events



Appendix 4

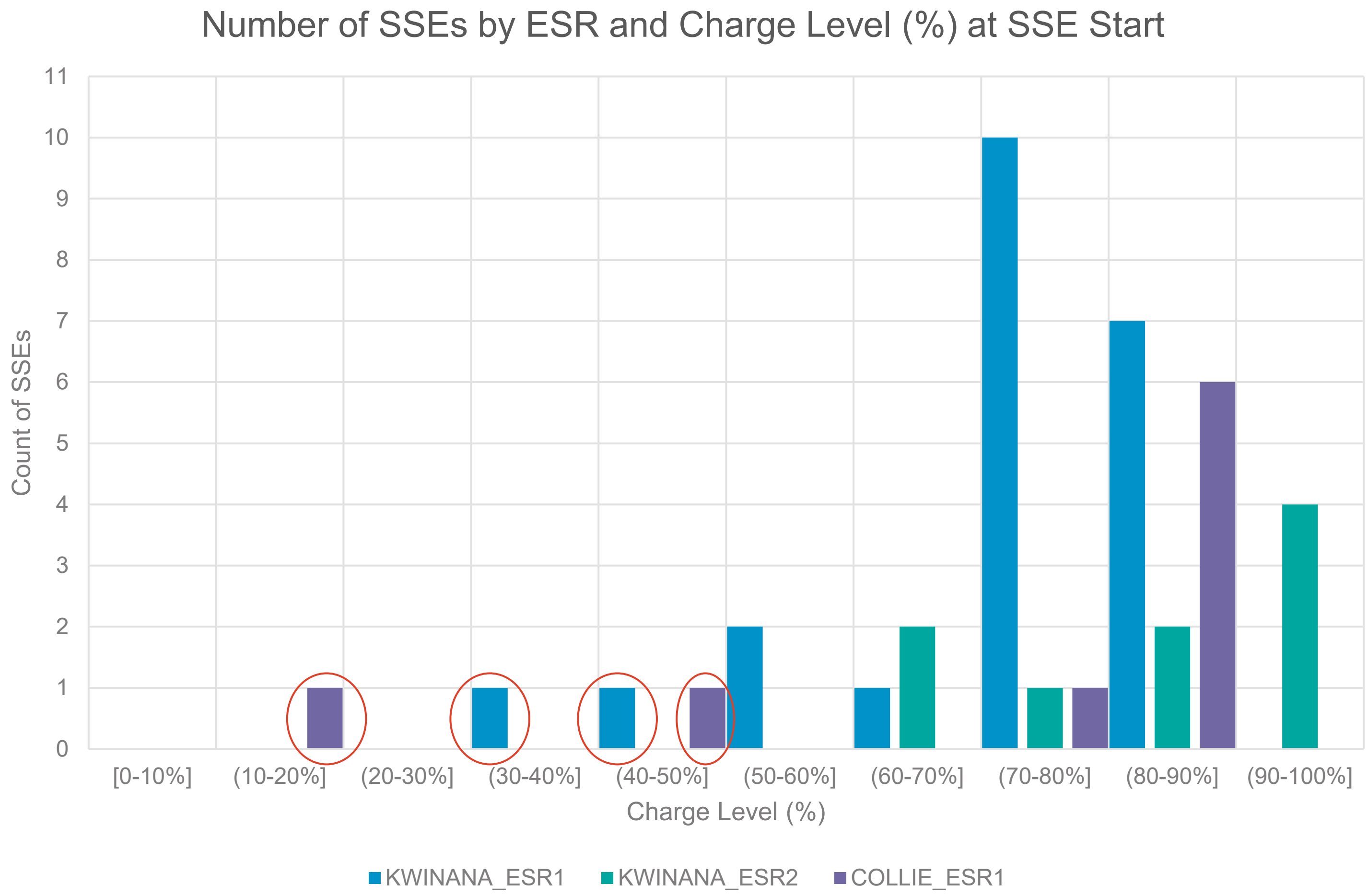
Stage 2: Current-State Technical Analysis – To inform CC2TRWG discussion

Stage 2 Current-State Technical Analysis

ESR Charge at Event Start for all SSEs

As part of Stage 2 of the CC2 Current-State Technical Analysis, of the 26 SSEs identified, the SSEs in which individual ESRs recorded charge levels below 50% at the start of the event were analysed.

- This chart shows the number of SSEs by charge level (%) of each ESR at event start
- The 4 SSEs selected for detailed analysis are circled in red

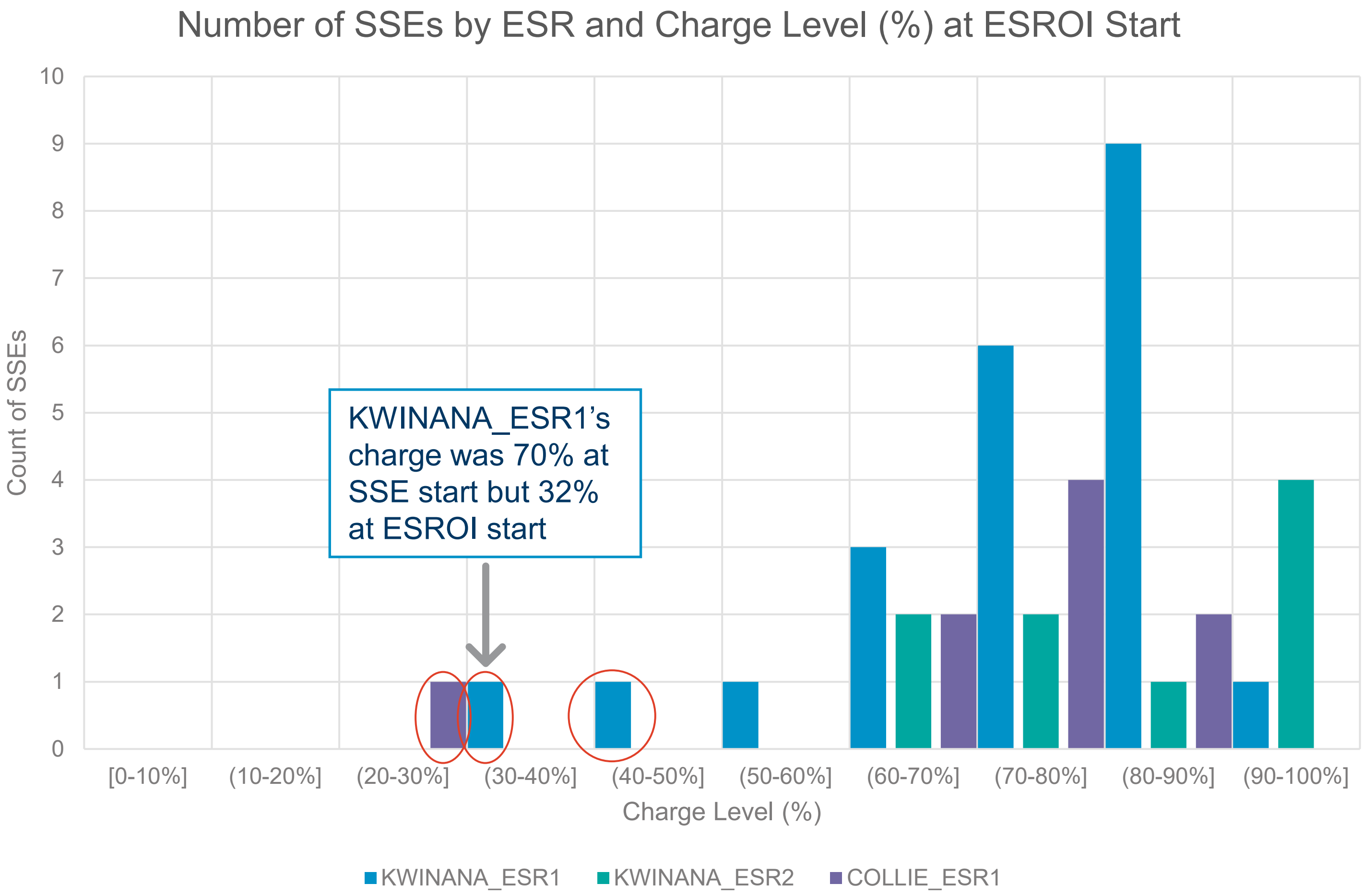


Stage 2 Current-State Technical Analysis

ESR Charge at ESROI Start for all SSEs

The SSEs in which individual ESRs recorded charge levels below 50% at the start of the correspondent ESROI were also analysed.

- This chart shows the number of SSEs by charge level (%) of each ESR at ESROI start
- The 3 SSEs when ESR charge was less than 50% at ESROI start are circled in red
- 2 of these 3 SSEs had an ESR charge level below 50% both at event start and ESROI start
- For the remaining SSE, on 11/12/2024, KWINANA_ESR1 was 70% charged at event start at 15:00, however, later at ESROI start it was only 32%.
    - This is the fifth SSE subject to further analysis



Stage 2 Current-State Technical Analysis

5 SSEs in Detail

The table on the right summarises the dates, start times, end times, and ESR charge levels, both at the event start and ESROI start, for the 5 SSEs in which individual ESRs recorded charge levels below 50% whether at event start or at ESROI start.

One SSE commenced after the ESROI start time, and COLLIE_ESR1 charge level was below 50% both at event start and ESROI start (highlighted in turquoise).

#	SSE Date	SSE Start Time	SSE End Time	ESR Charge Level at SSE start	ESR Charge Level at ESROI start	ESROI Start
1	13/01/2024	16:00	20:00	KWINANA_ESR1: 35%	KWINANA_ESR1: 50%	16:30
2	10/12/2024	15:00	20:30	KWINANA_ESR1: 42%	KWINANA_ESR1: 62%	17:30
3	23/01/2025	13:00	20:30	COLLIE_ESR1: 44%	COLLIE_ESR1: 64%	17:30
4	25/08/2025	17:45	23:40	COLLIE_ESR1: 17%	COLLIE_ESR1: 22%	17:30
5	11/12/2024	15:00	20:30	KWINANA_ESR1: 70%	KWINANA_ESR1: 32%	17:30

Stage 2 Current-State Technical Analysis

FCESS

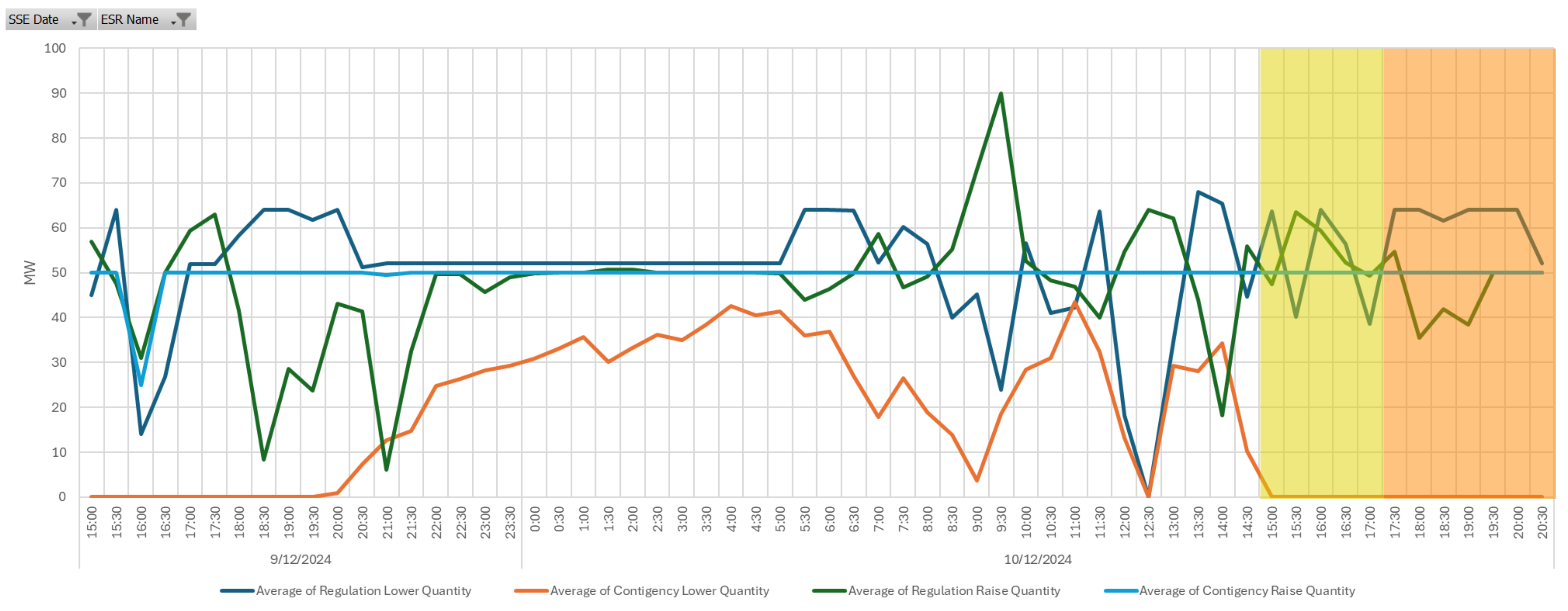
FCESS quantities for the 4 SSEs where ESRs had less than 50% charge at the start of the events were analysed. However, no clear pattern was observed to suggest that low charge levels were related to FCESS dispatch.

The graph in the following slide is an example of FCESS quantities for an SSE:

- It covers the period from 24 hours prior to the start of the SSE through to the end of the SSE;
- The orange shaded rectangle indicates the duration of the ESROI, while the yellow rectangle indicates the start of the event; and
- The lines represent FCESS quantities (Regulation Lower, Contingency Lower, Regulation Raise, and Contingency Raise) in MW for the ESR specified in the slide title

SSE 2: FCESS

SSE 10/12/2024 from 15:00 to 20:30 KWINANA_ESR1 had 42% charge level at event start



SSE Cause	Extreme Temperature Conditions (Heatwaves)

ChargeLevel/DischargeLevelV2 vs. Energy Price

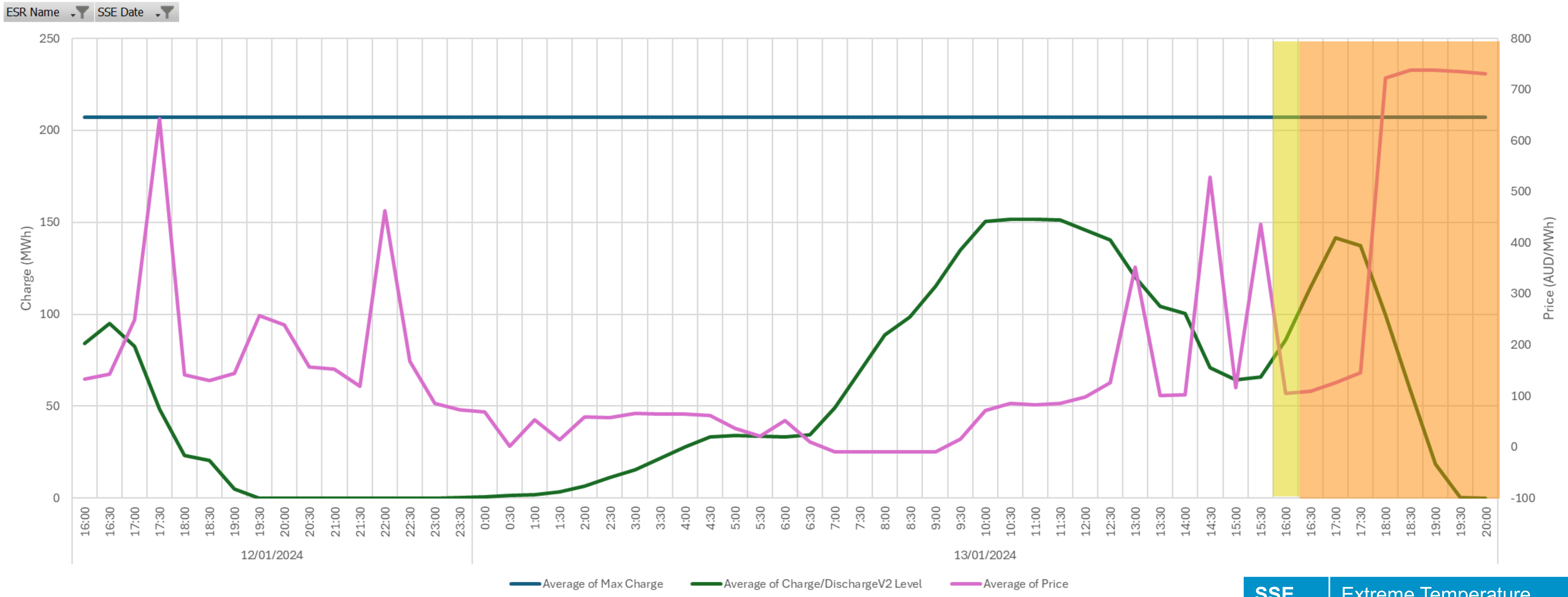
Introduction

The following graphs compare ChargeLevel/DischargeLevelV2 (measures same variable) with WEM Energy Prices for the 4 SSEs where ESRs had less than 50% charge at the start of the events:

- From November 2023 to 13/05/2024 ChargeLevel data is used, while from 13/05/2024 onward DischargeLevelV2 is used to represent ESRs charge in MWh for each dispatch interval
- Each graph covers the period from 24 hours prior to the start of the SSE through to the end of the SSE
- Orange shaded areas indicate the duration of the ESROI, while yellow shaded areas show the event start
- Pink lines represent WEM Energy Prices (AUD/MWh), dark green lines the ESR ChargeLevel/DischargeLevelV2 (MWh), and dark blue lines the ESR maximum charge (MWh)

SSE 1: ChargeLevel/DischargeLevelV2 vs. Energy Price

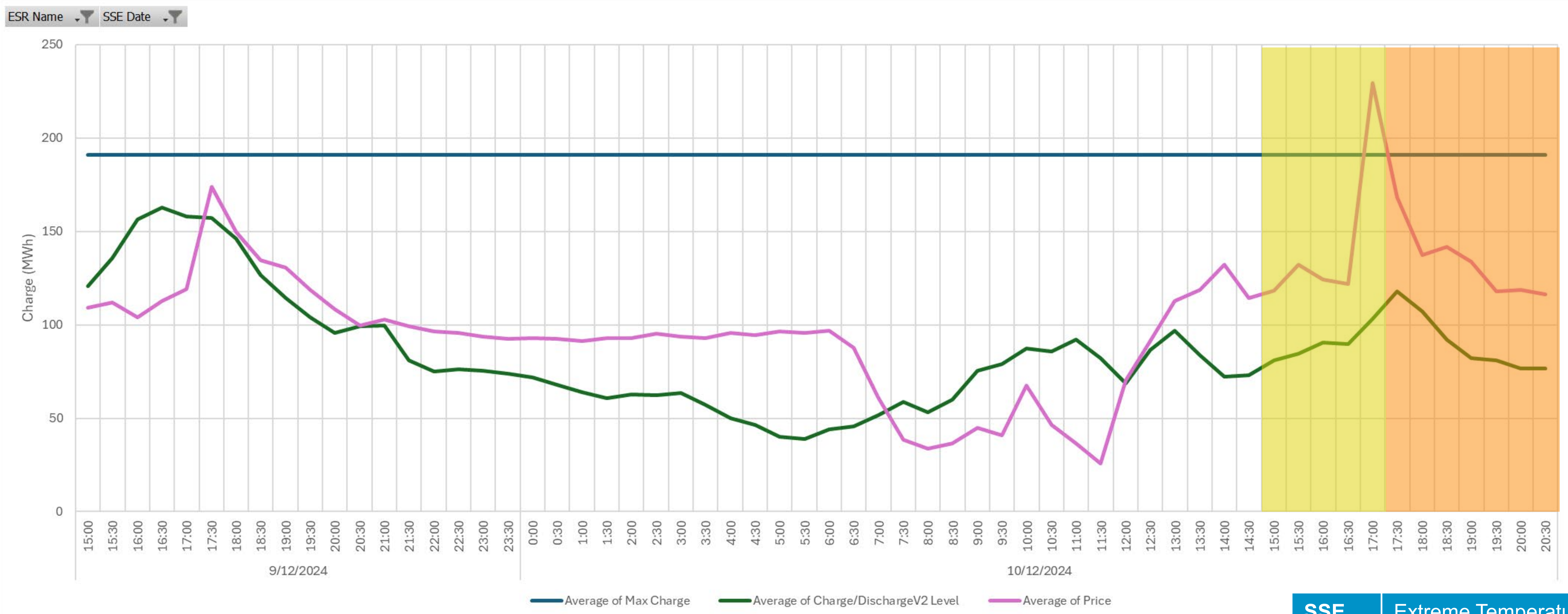
SSE 13/01/2024 from 16:00 to 20:00 KWINANA_ESR1 had 35% charge level at event start



SSE Cause	Extreme Temperature Conditions (Heatwaves)

SSE 2: ChargeLevel/DischargeLevelV2 vs. Energy Price

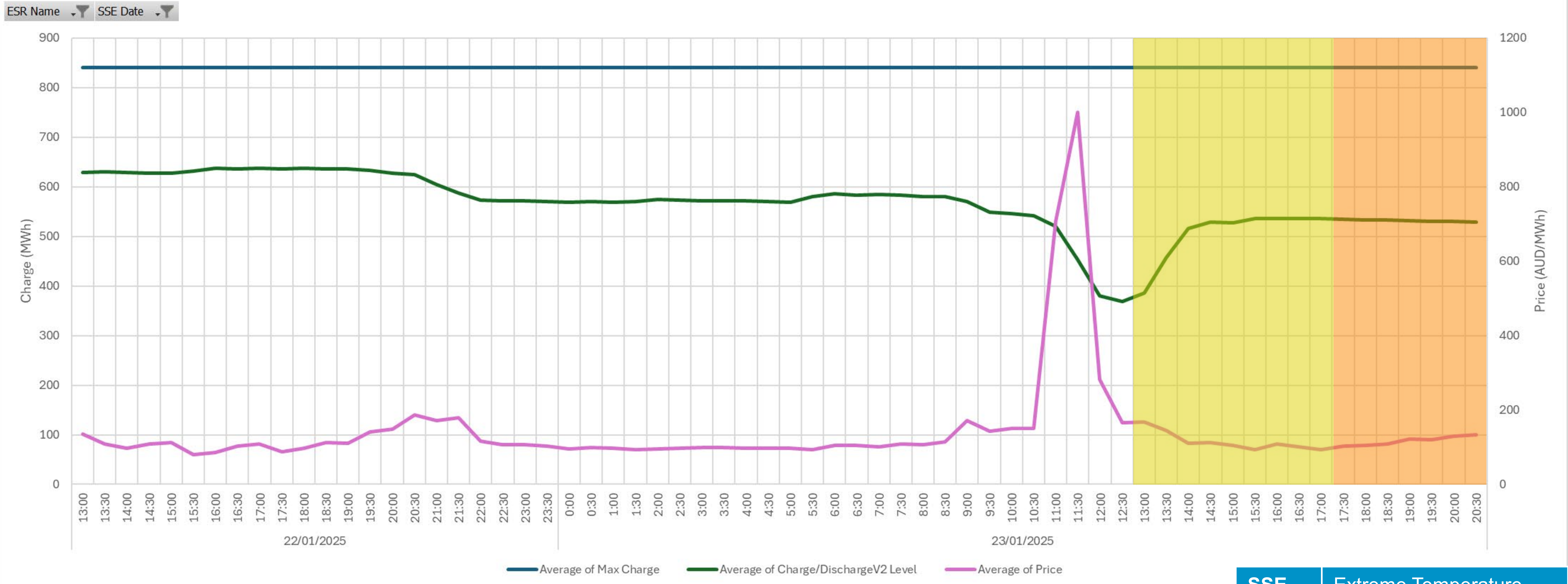
SSE 10/12/2024 from 15:00 to 20:30 KWINANA_ESR1 had 42% charge level at event start



SSE Cause	Extreme Temperature Conditions (Heatwaves)

SSE 3: ChargeLevel/DischargeLevelV2 vs. Energy Price

SSE 23/01/2025 from 13:00 to 20:30 COLLIE_ESR1 had 44% charge level at event start



SSE Cause	Extreme Temperature Conditions (Heatwaves)

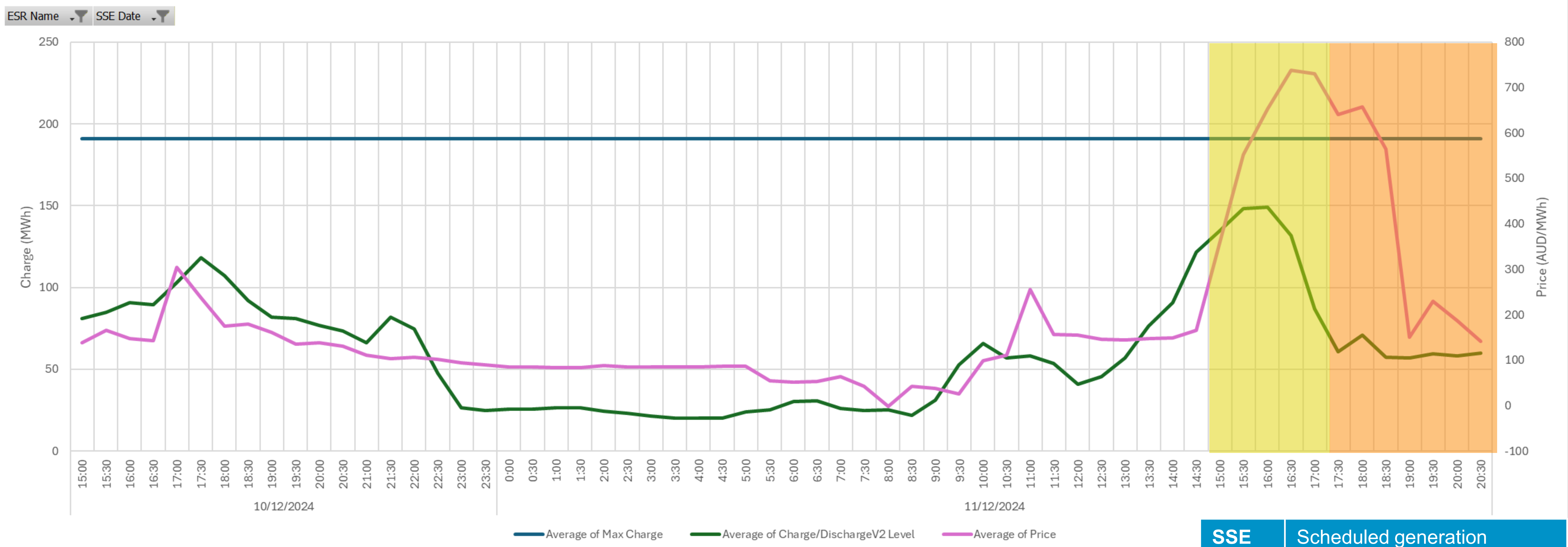
SSE 4: ChargeLevel/DischargeLevelV2 vs. Energy Price

SSE 25/08/2025 from 17:45 to 23:40 COLLIE_ESR1 had 17% charge level at event start

SSE Cause	Unusually cold, overcast and wet conditions

SSE 5: ChargeLevel/DischargeLevelV2 vs. Energy Price

SSE 11/12/2024 from 15:00 to 20:30 KWINANA_ESR1 had 32% charge level at ESROI start (orange)



SSE Cause	Scheduled generation Outages, low forecast wind availability, and high temperature forecasts

Stage 2 Current-State Technical Analysis

Low states of charge when entering SSEs or ESROIs appear to be primarily driven by high energy prices earlier in the day

- High prices result in ESRs being dispatched to discharge, and prevent full recharging

For all 5 SSEs analysed, the information available to EPWA suggests revenue earned from discharging earlier in the day was greater than the refund paid during ESROI on the same day:

- As a result, participants have an overall gain after paying refunds during the ESROI
- This suggests that the refund mechanism does not ensure that ESR participants enter the ESROI with a high state of charge

It was also observed:

- FCESS quantities do not show a clear explanation for the low ESR charge levels at event start, indicating that low charge does not appear to be related to FCESS dispatch

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Agenda Item 6: Reserve Capacity Prices paid to existing and committed generators

Market Advisory Committee (MAC) Meeting 2026_03_19

1. Purpose

MAC members to discuss the paper provided by Noel Schubert under General Business (Attachment 1) at the 11 February 2026 MAC meeting and the MAC feedback provided (Attachment 2).

2. Recommendation

That the MAC provide any additional comments.

3. Background

At the 11 February 2026 MAC meeting, Mr Schubert provided a paper under General Business seeking to discuss the following:

When reserve capacity prices climb steeply for reasons that are not related to existing and committed 'non-transitional' generators' capital costs, why should those generators get paid the same capacity prices as much-higher-capital-cost new-entrant generators (again at consumers' expense)?

There was not adequate discussion time at the 11 February 2026 MAC meeting for this issue.

Therefore, the Chair requested that the paper be made into an Agenda Item for discussion at the 19 March 2026 MAC meeting and that MAC members share their written feedback/comments regarding Mr Schubert's paper to all MAC members and the MAC Secretariat.

Feedback and comments were provided by eight MAC members and included in Attachment 2.

MAC members generally agreed with Mr Schubert that there are concerns with the increasing energy costs. However, several MAC members noted that they do not consider it appropriate to extend the transitional pricing arrangements for the reasons outlined in their feedback.

4. Attachments

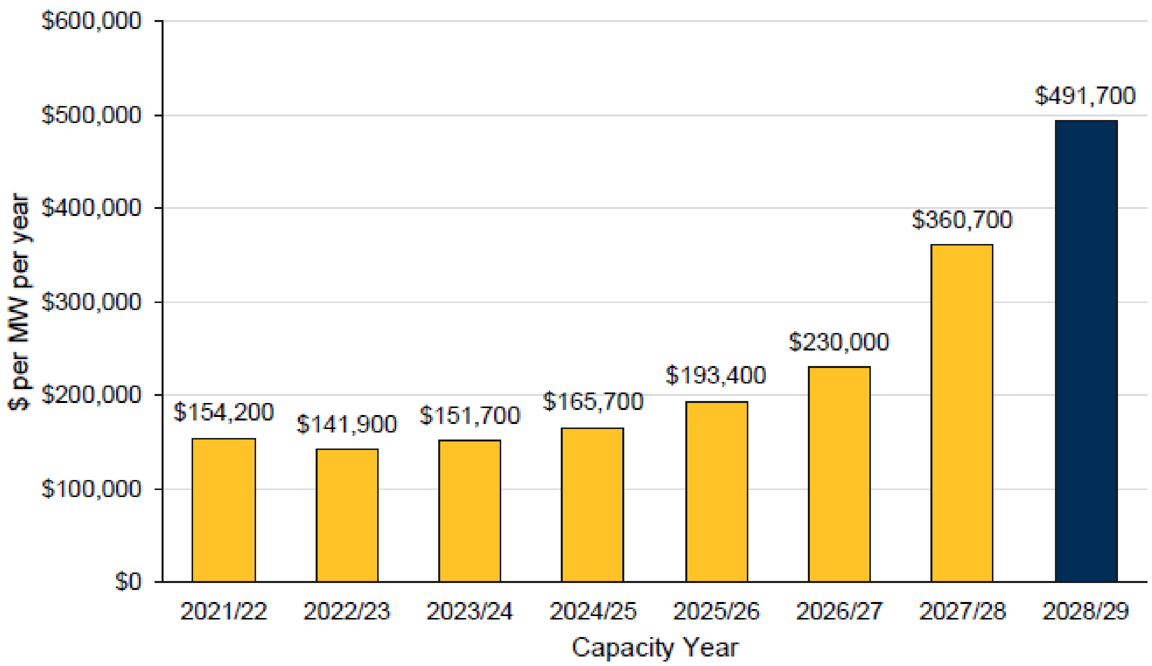
(1) Agenda Item 6 – Attachment 1 - Reserve Capacity Prices paid to existing and committed generators

(2) Agenda Item 6 – Attachment 2 – Summary of MAC member responses

Reserve Capacity Prices paid to existing and committed generators - comments from a consumer representative's perspective

- BRCPs are increasing almost exponentially - for various well-considered underlying reasons - to attract low emissions, new-entrant capacity and ensure it is viable. Refer to the latest ERA draft BRCP determination and its Figure 1.

Figure 1: BRCPs from the 2021/22 capacity year to 2028/29

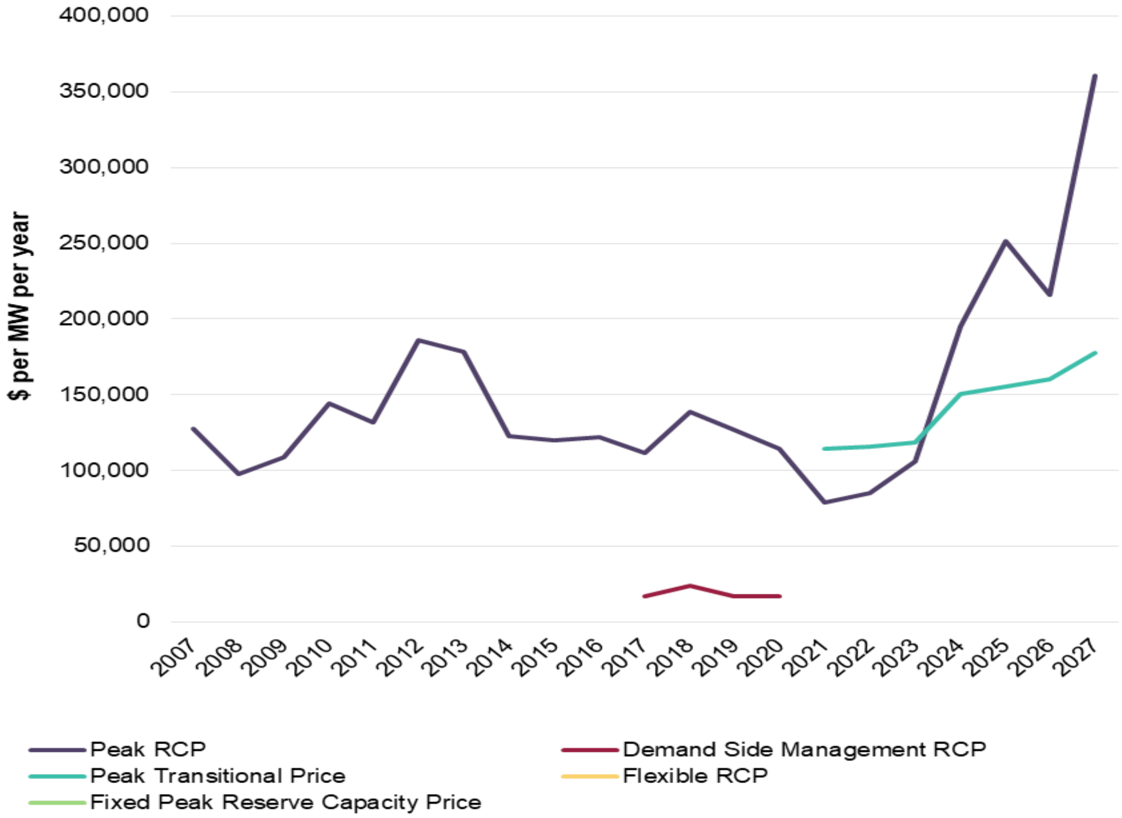


- Existing and new capacity needs to be financially viable in an ongoing timeframe.

- Revenue from the energy and ESS markets, and other sources if any, obviously needs to be taken into account when considering the overall viability of capacity sources. The WEM Investment Certainty review has been considering these issues including the potential declining energy prices due to renewables growth.

- Generators that are part of the 'Transitional' RCP mechanism receive peak capacity payments between a CPI-indexed price floor and price ceiling for capacity years 2021/22 until 2030/31 which keeps their capacity costs reasonable. See Figure 2.

Figure 2: Reserve Capacity Prices - source AEMO website



- These ‘peak transitional’ prices are relatively consistent and reasonable for existing capacity - much of which has paid off its capital costs - although there is a question of whether a generator that has paid off its capital costs should receive the same capacity payments (ultimately from consumers) as generators that are still to pay them off.

- Transitional capacity comprises a declining proportion of the existing fleet capacity as plant retires (90% in 2025/26 capacity year down to 64% in 2027/28 and decreasing). This means ‘non-transitional’ generators comprise 36% of fleet capacity in 2027/28 capacity year, and growing.

- When reserve capacity prices climb steeply for reasons that are not related to existing and committed ‘non-transitional’ generators’ capital costs, why should those generators get paid the same capacity prices as much-higher-capital-cost new-entrant generators (again at consumers’ expense)?

We welcome discussion on this, and views that support or don’t support continuation of the current and evolving arrangements.

Agenda Item 6: Attachment 2 – Summary of MAC member responses

Adam Stephen	Representing in MAC: Market Participant - Scheduled Facilities (Non-Intermittent Generating Systems)

The concerns regarding increasing costs are valid, however I believe this proposal (for lack of a better word), if progressed, will be to the long-term detriment of WA, disincentivising investment in new capacity and has potential to result in earlier removal of capacity from the market, irrespective of technology type.

Covering Capital costs is not/should not be considered the sole purpose of the reserve capacity price. All Capacity providers incur costs that cannot be covered through EVC bidding practises, and ongoing receipt of Reserve Capacity payments does allow for some of these costs to be covered.

The paper appears to advocate that electricity should be supplied 'at cost'. I do not believe such a position incentivises new investment nor supports continued investment in existing capacity. Furthermore, 'at cost' provision of services does little to incentivise technical/efficiency improvements by capacity providers once initially certified, potentially leading to overall reduced competition and no downward pressure on long term costs, particularly with regards to provision of reliability services.

We should also appreciate that historical and already known future reforms have increased regulatory risk associated with any project in WA (not just energy related but also commercial and industrial). Pursuing any form of 'forced reduction' to capacity price (whether actual or perceived) is likely to further increase these risk considerations and contribute to higher long-term costs of financing any new project in the state.

Patrick Peake	Representing in MAC: Market Participant - Sells, or intends to sell, electricity to customers

A suggestion has been put forward that generators which are currently being paid for reserve capacity based on the 'peak transitional' prices should remain on these prices after the planned end of this arrangement in 2030/31. The intention of this change would be to reduce total market costs which are passed through to customers. I am a MAC Member representing retailers who sell electricity to customers, so the possibility of slowing the increase in customer electricity prices appears to be an attractive option. However, I consider that this move has the potential to reduce system reliability and increase customer costs meaning that it is not in their overall interests. I put forward the following points based on Perth Energy's experience with ownership and operation of the Kwinana Swift gas turbine power station.

The obligation on all generating facilities is to be available 24/7 and able to start and run to full output with minimum notice. This obligation does not change over time so, irrespective of its age, a facility must be able to meet this requirement. To maintain this high level of reliability and availability, it is necessary to continue making significant investment into regular maintenance and overhauls. Hot gas path components in a gas turbine, for example, wear due to both start/stop events and hours of running so even if a facility has a relatively low utilisation, it still requires regular component replacement or repair.

Each time that a major repair is required, the question arises as to whether the facility should be brought back to a high standard such that it can run for a further 5-7 years or should we do just the minimum work required to meet our capacity obligations over the coming two years and then close the plant. The costs of both new and refurbished components have risen to such an extent over recent years, roughly in line with the increased cost of new machines, that this is a real question rather than something theoretical. Key drivers in this consideration are our estimate of what the facility will earn in the energy market, whether we can keep availability at a level that minimises refunds and what will the machine earn in the capacity market.

The increase in energy storage in the SWIS, along with increased behind the meter PV, has significantly smoothed market prices limiting the opportunity for a gas fired plant to earn energy revenue.

With intermittent generation rapidly replacing thermal plant, peaking plant is having to also take on the role of capacity firming. This is expected to increase the amount of plant cycling, raising the maintenance demand, while making operation less predictable.

Figure 2 on the document presented to the MAC shows that the reserve capacity price for transition plant has averaged around $130,000 per MW per year over the past 10 years. This is certainly not a figure which capacity investors would have considered 'reasonable' when making their investment decisions.

In summary, owners of transition plant now face the situation where:

- Future earnings in the energy market are likely to be more limited;
- The maintenance burden on their plant is likely to increase;
- Materials and labour costs for regular maintenance have risen dramatically and show no sign of abating;

- Transition facilities are well into the second half of their economic lives.

It is generally acknowledged that the SWIS will need gas fired plant for a prolonged period to firm up intermittent generation, especially with the upcoming closure of Synergy's coal fired plants. The lead time for new gas turbines is in the order of 4-5 years. If owners of existing plant are limited to never earning more than the transition price, there is a significant risk that they will not make the major investment required to keep their plants operating into the medium term. This will potentially leave the system short of gas fired plant raising prices to customers as well as increasing costs due to system unreliability. For this reason, I do not consider that the proposal is good for customers.

Graeme Ross	Representing in MAC: Contestable Customer

I represent contestable customers on the MAC and support the need for further discussion on the BRCP / Reserve Capacity price as raised by Noel at the last MAC.

Consumers (specifically contestable customers) in the SWIS are experiencing significant price pressure as a result of increases over the past few years in energy charges, ESS charges, and more recently NCESS charges.

Contestable customers in the SWIS are ultimately concerned about the delivered price of electricity. The capacity component is now forecast to become a more significant factor in the price of delivered electricity.

I acknowledge some (majority) of the responses provided by other members of the MAC and agree that there needs to be a long term incentive that attracts new generation / storage (and DSP's). It is generally accepted (though not by any means a certainty) that over the longer-term energy prices will decrease because of the expected increased concentration of generation / storage. However, it is my view that energy prices are unlikely to significantly decrease in the next 5 years and beyond the period when the end of the transitionary capacity price period occurs.

My main concern, therefore, is how do we mange the increased costs in the delivered price of electricity for the remainder of the transitionary period and for a period of time beyond.

I would encourage further discussion on the following (but not limited to);

- is there any possibility that the concept of a transitional capacity price could be extended or perhaps modified and extended beyond the current timeline?
- will the average energy prices / ESS prices offered in the market reduce as a result of increasing contribution made by the proposed capacity payments

My additional comment would be around the expected outcomes for consumers, for example, has any of the following been contemplated;

- An increasing number of contestable customers may be driven to seek behind the meter solutions with potentially unknown market outcomes
- will some industries exit the market or significantly reduce targets to electrify.

In both scenarios demand may be somewhat lower than expected.

I note the comments about the WEM Investment Certainty Review and perhaps that is the correct forum for these matters to be raised?

Rhiannon Bedola	Representing in MAC: Synergy, in its role as the only supplier of electricity to Non-Contestable Customers

I agree with Noel's over-arching concern that customers will be facing significant cost increases due to higher future BRCPs, coupled with the cessation of the transitional pricing that applies to facilities certified in the 2018 Capacity Cycle. However, I don't think it is appropriate to extend the transitional pricing period for this group of facilities. Continuing with the transitional pricing will likely result in earlier retirement of a random set of facilities at a critical time point in the energy transition.

I suggest that potentially the WEM Investment Certainty Review is used to undertake further work to review the costs to consumers and facility revenues and use a principle based approach focused on economic efficiency within the constraints of the market and the SEO. This review should not be limited to solely transitional versus non-transitional facilities, and should consider the investment signals and investment certainty that is provided throughout the various mechanisms within the WEM, ensuring that the WEM encourages investments (and divestments) when needed.

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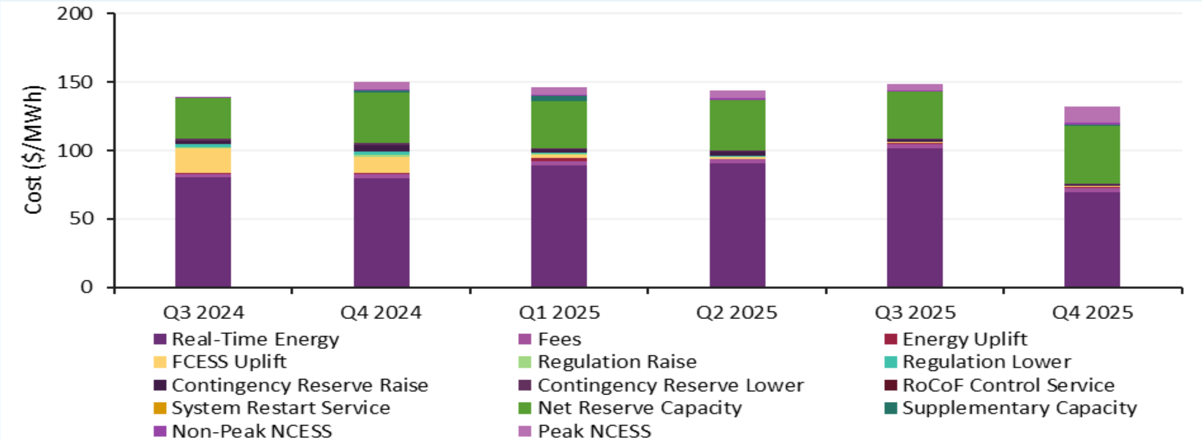
Tom Frood	Representing in MAC: Market Participant - Semi-scheduled Facilities (Intermittent Generating Systems)

I acknowledge the concern in the rise of the BRCP and how this could become problematic for consumers. I also note that in the latest QED the net cost of Reserve Capacity increased from 24% to 31% from Q4 24 to Q4 25. I recognise that a number of factors impact this very simple statistic, but this will more than double by 27/28. I also believe that the increase to the gross cost of power is unlikely to be in proportion to this increase as the batteries are facilitating more cheap renewables, providing cheaper energy and ESS, as we saw from 24 to 25 (again simplistic analysis of the reasons for the drop). See chart from the QED.



However I do believe that existing facilities do not need to be rewarded at the cost of the next generation that is needed for the system, I think they should be incentivised for the capex required at the time of investment. I think there should be a better approach to ensure reasonable returns for investors with less risk and less volatility for consumers.

I am also concerned about ensuring long term incentive that leads to the new generation that is required. Long term volatility in the BRCP does not help bring in new investment. Most investors would prefer less risk even if it means potentially lower returns. I believe that we would be better off having a fixed period to allow new entrants to recover their capital costs, at the rate set for the cycle year. This could be 10 years as per the transitional arrangements or some other duration. The capital cost of investment is incurred at the time of Financial investment decision/construction and is unaffected by changes in pricing and technological needs in following years, up or down. This would reward entrants for the addressing the need identified for a specific year, but doesn't provide a gamble/windfall that is hard to forecast, but must be included in financial models.

I of course agree that capacity providers need to make a profit. I don't believe that a system that rewards based on a gamble of what the future might or might not bring makes a lot of sense. I think that it would be better reflected in allowing some profit on top of the EVC rather than through the RC system. i.e. one possible approach could be to introduce a WACC or some other profit allowance into the Offer Construction Guidelines to be added to the EVC or some multiplying factor of the EVC itself. A WACC is closer to a regulated asset cost recovery approach, but the cost to consumers would follow real time cost changes as the EVC needs to follow live cost changes. Possibly there is a need for a lower on going credit payment for the remaining life to ensure long term capacity, but not related to the cost for new build in some unconnected future year of demand.

I appreciate that this is a more fundamental change to the market than maybe this paper was contemplating and could lead to a significant piece of work.

I agree with Noels comments – regulatory change is unavoidable and in this rapidly changing market inevitable.

Paul Arias	Representing in MAC Market Participant - Scheduled Facilities (Non-Intermittent Generating Systems)

Whilst I represent Market Participants with Scheduled Facilities (Non-Intermittent Generating Systems), I do understand the concerns put forward by Noel surrounding the cost impact of policy decisions relating to the Reserve Capacity Mechanism (RCM) and Benchmark Reserve Capacity Price (BRCP).

As other MAC members have articulated, I consider the suggestion to extend or alter the 'transitional arrangements' is inconsistent with the State Electricity Objective (SEO) as its presents risks to the reliability of supply of electricity and has the potential to increase the price of electricity.

Prior to the introduction of the 'transitional arrangements' for existing generation, existing and new capacity were valued the same, regardless of capital cost requirements (many significantly higher than the reference OCGT technology), with the BRCP set based on the cheapest new entrant to meet the peak system requirements and then adjusted based on shortfall or excess capacity to set the Reserve Capacity Price (RCP).

This mechanism ensured that existing generations contribution to meeting peak system requirements (contribution to system security and reliability) was valued based on the cost to replace its contribution with the cheapest option, i.e. a new diesel OCGT facility. There was no 'missing money' consideration in the RCM for more expensive capacity types. For these capacity types to enter, long-term bilateral contracts were required, often providing a higher fixed revenue component than the RCP.

The 'transitional arrangements' were implemented as part of reforms aimed at sharpening the response of the RCP to the level of excess capacity. The RCP curve was changed to allow the RCP to set at $0/MW at 30% above the Reserve Capacity Target, reforms implemented when there was significant excess of reserve capacity. The recent RCP curve reforms have implemented a RCP floor (50% BRCP at 15% excess) for peak and flexible capacity, implemented when capacity shortfalls were forecast.

The RCM (and its reforms) are the primary investment signal provided to the market, what is the appropriate signal the WEM needs to send now? The 2025 AEMO ESOO highlights the sensitivity of the WEM to facility retirement and that investment in new generation sources will be required from 2027-28. Reforms to extend or alter 'transitional arrangements' represents significant sovereign risk for existing facilities and new entrants, altering investment (major maintenance or new build) timelines and more likely to result in reduced reliability of supply of electricity and increases the price of electricity.

The transitional arrangements will end following the 2030/31 capacity year, at which point the average WEM transitional facility age is ~20 years and averages ~23 years for larger facilities (> 100 CRC, subject to Bluewaters retirement dates). Many of these facilities will support the WEM to mid-2030 but probably not much beyond this date (due to various factors including the draft policy for penalties on high-emission technologies), therefore the suggestion of extending the 'transitional arrangements' may serve to 'kick the can' down the road with respect to the short term view of the rising cost of electricity but not for long. The suggested changes to the 'transitional arrangements' may result in deferred or cancelled major inspections, impacting the aging generation's reliability and bringing forward the longer-term increase in price of electricity for consumers, if these transitional facilities ultimately decide to cease operations.

The suggested direction in the discussion paper presented to MAC points to a fundamental shift in how capacity is valued in the WEM, based on capital cost recovery for facilities based on age and technology type, a significant reform of the RCM will be required to achieve this objective. The RCM at its core has always been designed to value capacity based on its contribution to system security and reliability. A departure from this, as suggested by this discussion paper, undermines this core concept and cannot be considered in isolation.

Alister Alford	Representing in MAC: Market Participant - Demand Side Programmes

DSPs work closely with a broad cross section of end use customers. I agree with the underlying concern that customers are facing significant cost increases impacting the competitiveness of WA businesses.

Discussing the draft BRCP with my international colleges we could not identify any other major capacity market with higher effective capacity prices. From this perspective, it's reasonable to question if the current mechanism is effective at exposing the 'true marginal cost' for incremental capacity expansion.

Where capacity prices are inefficiently high there's also the potential for increased risk aversion from aggregators relying on portfolio effects and over provisioning to deliver dependable responses. That is, more flexible demand is required to operate a DSP within a fixed risk budget leading to less DSP response being offered to the capacity market.

As a DSP participant I'm inclined to lean into the principle that the RCM should be designed to value capacity based on its contribution to system security and reliability regardless of the capacity technology and time in market.

Also, if a fundamental shift in how capacity is valued is proposed then it should not be considered in isolation from the mechanism to set the RCP. Given the substantial expenditure in effort on the RCM reform to date, the prospect of testing whether other mechanisms such as capacity auctions are more efficient in the altered context is a significant task.

Jacinda Papps	Representing in MAC: Market Participant - Scheduled Facilities (Electric Storage Resources)

The paper notes that the Benchmark Reserve Capacity Price is increasing and asks why should existing and committed generators get paid the same as new entrants that (presumably) have much higher capital costs.

I consider that the Reserve Capacity Mechanism should continue to pay a single capacity price per capacity product for the following reasons:

<u>Level playing field & investment signals</u>.

A uniform price for each capacity product ensures competitive neutrality and clear investment signals. Differentiating payments based on a technology's capital costs or vintage would be complicated and contestable and distort signals for investors. Investors would no longer invest based on meeting requirements at least cost and instead focus on which technologies have the most favourable administered prices. In this way the differential pricing regime would “pick winners” rather than allowing the market to solve.

<u>A differential pricing regime would be unworkable</u>

If all generators are to be paid different prices, then how should they be priced? There would need to be rules to define and price for each class of existing or new plant. For example, which technology and duration to reference, how much fixed-cost recovery remains, and whether past or future policy changes should be compensated. This would turning price-setting into a perpetual, case-by-case cost-of-service exercise. This would also increase exposure to administrative regulatory decisions, discouraging investment.

<u>Establishing a differential pricing regime could be a knee-jerk and piece-meal reaction. A solution to rising costs should be holistic and enduring and preserve a single RCM price</u>

It may be that recent BRCP increases may not persist as storage costs continue to fall. If high outcomes do persist, the issue may be more in the underlying settings, for example, whether the benchmark technology is fit for purpose, or the duration requirement and how it can increase the benchmark technology cost as more storage increases or the load shape changes. The optimal solution should balance consumer exposure to costs with the need to continue the RCM as a single-price mechanism

<u>The transitional price served a different purpose</u>

While the transitional price arrangements caused differential pricing, this was not based on presumptions about relative costs, nor did it establish an enduring regime based on vintage. It was to “ameliorate perceived revenue risk associated with the new capacity pricing and procurement framework, within reasonable limitations.”

Noel Schubert	Representing in MAC: Small-Use Consumers

Additional comments from Noel Schubert in response to Adam Stephen 13 February 2026:

The last bullet point question in my discussion paper is what I am hoping our discussion can address:

"When reserve capacity prices climb steeply for reasons that are not related to existing and committed 'non-transitional' generators' capital costs, why should those generators get paid the same capacity prices as much-higher-capital-cost new-entrant generators (again at consumers' expense)?"

Stated another way: "Why should these generators receive windfall revenue gains, in excess of what they need to remain viable - i.e. make reasonable profits that are enough for them to continue to participate in the WEM - rather than excessive profits at consumers' expense which may make consumers' businesses unviable?" How can we achieve this balance under the current circumstances where the BRCPs are rising so steeply?

- Discussion paper statement: "Existing and new capacity needs to be financially viable in an ongoing timeframe". We need revenue to generators from all sources to be sufficient for them to be attracted to provide required new capacity and to continue to participate in the WEM for as long as they are needed, at efficient costs. They need to make reasonable profits to achieve this, not just cover costs (response to Adam's point below). Their revenue should also not be excessive adding unnecessarily to consumer costs.
- Revenue from all sources needs to allow reasonable profits. The adequacy of revenue from capacity prices versus that from the energy and ESS markets will vary for different technologies and how they participate in the market - including revenue determined by bilateral contract arrangements which are not visible to the market.
- Generators need to make reasonable profits while they are needed and remain competitive and efficient.
- Ongoing changes to regulation and the ESM rules, create risk for existing generators and financing of new generators, with flow-on risks to energy consumers - including the risk of energy costs increasing too much for businesses to remain viable.

Additional comments from Mr Schubert 18 February 2026:

The adequacy of generator earnings from all sources (energy market and ESS, capacity prices, RECs, other) need to be taken into account in deciding whether any changes are required. The WEM Investment Certainty review intended to consider this and I think should continue to do so. The CC2TR (Capacity Class two Technology Review) is also considering related matters.

The 'administered price' design of the Reserve Capacity Mechanism doesn't result in strong competition to keep capacity prices reasonable and efficient for both consumers and generators, and so appropriate checks and balances are required. Are they adequate?

Additional comments from Mr Schubert 25 February 2026:

1. Re the age of plant - Muja 7 and 8 reached 41 and 40 years old respectively in 2025, so by their announced 2029 retirement date they will be 45 and 44 years old. Collie power station is only 26 years old (commissioned in 1999) and so will only be 28 years old by its

announced 2027 retirement date. I generally think of coal plant having a design life of about 40 years. The Mungarra and Pinjar OCGTs were installed in 1990-93, so are getting on even now compared to the 30 years I think of as a typical design life for OCGTs. It's just background to our discussion - adding to Paul's comments about the age of plant.

2. See the following extract from my spreadsheet comparing WEM capacity costs from different sources (NCESS, SRC not shown here) based on published data. In capacity year 2027-28, 'non-transitional' capacity ('Post 2019 RCP' row) will make up 36% of the capacity, but 54% of the total capacity costs (excluding NCESS and SRC) of $1.558 billion - which is double the current capacity year's total capacity cost (2025-26) - based on published capacity prices. The following capacity year total (2028-29 - not determined yet) will be much higher again based on the ERA's draft BRCP - $491,700/MW per year, with a higher proportion of non-transitional capacity. At present I am more concerned about the prices non-transitional capacity - for DSP and any plant that committed to build based on lower future capacity price assumptions - getting much higher prices than are necessary or reasonable in those future years.

Comparison of WEM Capacity Costs									
Costs are based on capacity credits paid for at the prices shown, not allowing for any other prices used in bilateral trades which are not public.	2025-26			2026-27			2027-28		
Capacity Year (1 October to 1 October)	$/MW/ annum	MW	Total Annual Cost ($m)	$/MW/ annum	MW	Total Annual Cost ($m)	$/MW/ annum	MW	Total Annual Cost ($m)
Capacity Scheme or Source:									
Reserve Capacity Prices & Costs:									
ERA Benchmark RCP	193,400			230,000			360,700		
Post 2019 RCP	251,420	447	112	216,092	1,642	355	360,700	2,326	839
Transitional RCP	155,419	4,270	664	160,392	4,310	691	177,636	4,049	719
Sub-total		4,717	776		5,952	1,046		6,375	1,558

Gentailers who have their own, and/or contracted, capacity that matches their IRCR exposure reasonably well will not be affected much overall by capacity price increases ('swings and roundabouts' as the generation arm gets paid more, but the retail arm pays more based on its IRCR). Pure retailers will be very exposed, and customers who have the IRCR cost passed through to them. Pure generators would be very happy with the higher capacity prices. This is simplistic, but WIC review work could explore the likely overall impact in appropriate detail.

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Agenda Item 7: WEM Operation Effectiveness Report – Progress Update

Market Advisory Committee (MAC) Meeting 2026_03_19

1. Purpose

Energy Policy WA (EPWA) to update the MAC on the progress of implementing the recommendations from the Coordinator of Energy's (Coordinator's) inaugural Wholesale Electricity Market (WEM) Operation Effectiveness Report.

2. Recommendation

That the MAC notes:

- the update on the progress of implementing the recommendations from the first WEM Operation Effectiveness Report since the previous MAC meeting, which are shown in red in the Tables below; and
- the recommended approach to implement Provision of clearer information to Market Participants regarding the current priorities and focus of the ERA's surveillance and compliance activities (Attachment 1).

3. Background

Under clause 2.16.13D of the Electricity System and Market (ESM) Rules, the Coordinator must provide the Minister of Energy (Minister) with a report dealing with the matters identified through its market monitoring activities at least once every three years, with the first such report due by 1 July 2025.

The Coordinator provided the first WEM Operation Effectiveness Report (the Report), that covered matters outlined in clauses 2.16.13A, 2.16.13B and 2.16.13E of the ESM Rules, to the Minister on 25 June 2025.

- After consultation with the Minister, the Coordinator published a version of the Report on 8 July 2025 on the Coordinator's website.
  - Any confidential and/or sensitive data was either aggregated or removed.
- The published report is to serve as a point of reference of further work required by AEMO, the ERA, EPWA and Western Power to improve market effectiveness, including through future ESM Amending Rules.

4. Attachment

Agenda Item 7 – Attachment 1 – Recommended Approached

Table 1 – Recommendations relevant to all Market Bodies

Recommendation	Status	Update
Proactive reporting of Market Bodies on WEM design flaws and areas for improvement	Ongoing	EPWA, AEMO and the ERA have established fortnightly Market Surveillance meetings to discuss WEM design flaws and areas for improvement. Updates, as appropriate, will be provided to the MAC by EPWA or the AEMO at its relevant forums. Additionally, AEMO and EPWA have established regular meetings at Executive level and are working together to establish a new 'Market and Systems Issues Log' that will enable improved information sharing and tracking of solutions between the two agencies.
Improvement of accessibility across all market bodies' websites and published materials	Ongoing	On 17 September 2025, the ERA implemented a new website design, moving to a function-based structure and restructured its WEM section. Western Power's webpage 'The Wholesale Electricity Market and Market Information Management' lists its WEM Procedures, Guidelines and other market information. This new page is also easily discovered by search engines.

Table 2 – Recommendations relevant to AEMO

Recommendation	Status	Update
Provision of further detail on the cause of any direction/intervention by AEMO.	Ongoing	The ongoing Frequency Co-optimised Essential System Services (FCESS) Cost Review (Stage 2) is addressing this proposal.
Improvements in relation to operational forecasting.	Ongoing	The ongoing Operational Forecasting Review is addressing this proposal. In parallel to the Review, AEMO has initiated an internal Project to uplift AEMO's operational forecasting capabilities, which includes several initiatives aligned with EPWA's proposals.
Completion and publication of WEM Procedures in a timely manner, including prompt updates when required.	Ongoing	The WEM Procedure Content Review will address some of the issues highlighted in the Report. As highlighted in the Report, there were still nine WEM Procedures outstanding from the date of the new WEM commencement. AEMO has since finalised and commenced five, one is being finalised post-consultation, and the remaining three have had drafts completed and are expected

Recommendation	Status	Update
		to be published for consultation in the coming weeks (noting that MT PASA is currently being amended to reflect the interim process being developed as explained to industry at the July 2025 AEMO Procedure Change Working Group and notified to MAC). AEMO has also implemented new internal processes to support the timely development of Procedures, including uplifted Procedure tracking and reporting tools that will enhance monitoring by Managers and the Senior Leadership Team, and highlight resourcing requirements and risks early.
Making complete and verified market data available through the publicly accessible web portal in easily accessed data formats.	Ongoing	AEMO's Data Dashboard uplift project is a priority initiative for FY26 and will help address the findings from the Report around the availability of data through AEMO's website. The feasibility stage commenced in November 2025 and is now concluded. AEMO has progressed into the planning stage and has commenced activities to improve access to public datasets (providing alternative to .JSON files). AEMO conducted a WEM Data Dashboard survey and held workshops in mid-2025, the findings of were considered when defining the scope of the uplift project. Currently the project is scheduled for completion in late 2027 (noting this is subject to change).

Table 3 – Recommendations relevant to the ERA

Recommendation	Status	Update
Provision of clearer information to Market Participants regarding the current priorities and focus of the ERA's surveillance and compliance activities, noting that confidential information must be protected.	Ongoing	See Attachment 1 for the recommended approach regarding annual priorities

Table 4 – Recommendations relevant to Western Power

Recommendation	Status	Update
Transformation of the Transmission System Plan, in the medium term, into a broader Networks Plan that includes a complete transmission and distribution development roadmap, to provide an informed view of investment opportunities. Supporting information should include constraint data, cost-benefit analyses and improved distribution level heat maps.	Starting	To be commenced.

Table 5 – Recommendations relevant to EPWA

Recommendation	Status	Update
The Coordinator will work with the Market Bodies and other stakeholders on how to integrate the State Electricity Objective more broadly within the ESM Rules and will monitor this in the next WEM Operation Effectiveness Report.	Starting	To be commenced.

Attachment 1 - Progressing a recommendation from the WEM Operation Effectiveness Report

Relevant Recommendation from the WEM Operation Effectiveness Report

Provision of clearer information to Market Participants regarding the current priorities and focus of the Economic Regulation Authority's (ERA's) surveillance and compliance monitoring activities, noting that confidential information must be protected.

Proposed Approach

EPWA recommends including an obligation in the Electricity System and Market (ESM) Rules for the ERA to publish annual surveillance and compliance monitoring, and enforcement priorities.

Background

The WEM Operation Effectiveness Report (Report) recommended several areas to improve transparency in the Wholesale Electricity Market (WEM). One key recommendation was to provide Market Participants with clearer information on the current priorities and focus of the ERA's surveillance and compliance monitoring activities.

Greater transparency regarding the ERA's surveillance and compliance priorities would encourage Market Participants to enhance their internal compliance due diligence, reducing the likelihood that issues escalate to ERA interventions. Higher degree of compliance will better achieve the State Electricity Objective by supporting the system reliability and ensuring that prices reflect the efficient cost of electricity supply.

In response, the ERA noted that it operates within the existing legislative and regulatory framework, and any changes to its approach would require amendments to the regulatory framework.

To explore options to enhance transparency, EPWA has examined regulatory frameworks in other jurisdictions to identify potential changes.

Review of approaches in other Jurisdictions

In the review, the ERA was benchmarked against selected peer regulators to identify indicators of best practice. The following peers were chosen either because they were referenced in the Report or because they operate in a comparable regulatory environment to the ERA.

Australian Energy Regulator (AER)

Each year, the AER publishes Compliance and Enforcement Priorities to highlight the areas where it will focus its attention. The annual priorities complement, rather than replace, the AER's broader functions, and the AER continues to act on other serious issues as they arise.

Commonwealth regulators aim to align with the guidance on regulator performance provided by Australian Government's Department of Finance.[1] In September 2022, Energy Ministers

[1] Regulator Performance (RMG 128) | Department of Finance

agreed on a Statement of Expectations for the AER, and the AER aligns its work with these expectations.[2]

The annual priorities are aligned with both the objectives of the AER's multi-year Strategic Plan and the expectations set by Ministers.

Priorities are determined through a risk based and data driven approach to ensure a focus area is of the greatest importance and impact.

The AER reports on its performance against these priorities in its annual report, demonstrating how it is meeting both the Ministers' expectations and its strategic commitments.

Australian Competition & Consumer Commission (ACCC)

Each year the ACCC publishes Compliance and Enforcement Priorities to highlight the areas in which it will focus its attention. These annual priorities sit alongside the ACCC's enduring priorities. The ACCC also retains the capacity to pursue other significant matters and to continue remaining work on previously identified priorities.

Commonwealth regulators aim to align with the guidance on regulator performance provided by Australian Government's Department of Finance.[1] The Australian Government has issued a Statement of Expectations, and the ACCC aligns its activities with these expectations.[3]

These priorities reflect the ACCC's legislative functions as well as the expectations set by the Australian Government.

Priorities are finalised following external consultation and an assessment of existing or emerging issues and their impact on consumer welfare and the competitive process.

The ACCC reports on its performance against these priorities in its annual report, demonstrating how it is meeting both the Government expectations and its legislative obligations.

Office of Gas and Electricity Markets (Ofgem)

The Forward Work Programme sets out Ofgem's priorities and planned projects for each upcoming financial year. The Forward Work Programme is in addition to Ofgem's routine activities in exercising its statutory functions.

Under section 4(1) of the *Utilities Act 2000* (UK), Ofgem must publish, before the start of each financial year, a forward work programme containing a general description of the projects it plans to undertake during that year. Section 4(2) requires that this description also includes the objective of each project.[4]

Ofgem aligns the Forward Work Programme with its multi-year Strategic Plan and any duties assigned by the UK Government.

Priorities are finalised following external consultation but can change if Ofgem must refocus on another activity to protect the interest of consumers.

Under section 5 of the *Utilities Act 2000* (UK), Ofgem must report annually on its progress in delivering the programme.

Competition and Markets Authority (CMA)

The Annual Plan sets out how the CMA will prioritise its activities to achieve its objectives for the upcoming financial year. In addition to delivering on its Annual Plan objectives, the CMA will continue to carry out its statutory functions.

[2] Statement of Expectations and Statement of Intent 2025-26 | Australian Energy Regulator (AER)

[3] Statement of Expectations and Statement of Intent | ACCC

[4] Utilities Act 2000

Under Schedule 4, Section 12 of the *Enterprise and Regulatory Reform Act 2013 (UK)*, the CMA is required to prepare and publish an annual plan for each financial year.[5] Schedule 4, Section 12(2)(a) further requires that the plan must set out the main objectives for the year and indicate their relative priorities.

The CMA aligns each Annual Plan with its multi-year Strategy and with any expectations set by the UK Government through a Strategic Steer. The priorities in the Annual Plan are finalised following external consultation.

Under Schedule 4, Section 14 of the *Enterprise and Regulatory Reform Act 2013 (UK),* the CMA must report annually on its progress in achieving the objectives set out in the Annual Plan.

Under Section 171 of the *Enterprise and Regulatory Reform Act 2013 (UK),* the CMA is required to publish guidelines explaining how it decides whether to commence an investigation. To supplement this, the CMA provides guidance on how it conducts market reviews, as well as how it monitors and evaluates market remedies.

Findings

EPWA has assessed the different approaches identified in the review of the other jurisdictions. EPWA considers that the UK model, in which a regulatory obligation is imposed directly on the regulator, is the most effective option for WA.

Adopting an approach similar to the AER and ACCC would require developing regulator performance guidance for the ERA surveillance and compliance monitoring functions and that the Minister for Energy issues a Statement of Expectations. This approach would involve significant administrative effort and likely require coordination with other departments, such as the Department of Treasury and Finance (WA).

In contrast, the UK model places an annual regulatory obligation on the regulator without detracting from its existing statutory functions. It also provides flexibility, enabling the regulator to align its priorities with its strategic plan or adjust them in response to emerging expectations.

Proposal to amend the ESM Rules

EPWA considers that implementing an obligation within the ESM Rules for the ERA to publish annual surveillance and compliance monitoring, and enforcement priorities would provide transparent and adaptable framework.

EPWA proposes that the new obligations would require the ERA to:

- publish its annual compliance monitoring and enforcement priorities before the start of each Financial Year; and
- publish a general description of the work (other than routine activities undertaken in the exercise of the ERA's surveillance and compliance monitoring functions) that the ERA plans to undertake during the year to support addressing the priorities.

EPWA proposes that the ERA should not set its annual priorities through public consultation. Instead, the ERA should identify priorities using a risk-based, data-driven approach, focusing on areas that are most important and have the greatest potential impact on the State Electricity Objective. This approach is similar to the method used by the AER.

EPWA does not recommended that the ESM Rules require the ERA to report on its performance against these priorities in its Annual Report. The ERA's Annual Report is governed by separate Western Australian legislation and regulations.

EPWA proposes to develop draft ESM Amending Rules that draw upon similar obligations in relevant UK legislation.

[5] Enterprise and Regulatory Reform Act 2013

Department of
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GOVERNMENT OF WESTERN AUSTRALIA

Energy Policy WA

Agenda Item 8: Market Development Forward Work Program

Market Advisory Committee (MAC) Meeting 2026_03_19

1. Purpose

- To update the MAC on changes to the Market Development Forward Work Program since the previous MAC meeting, which are shown in red in the Tables below.
- Rows that are shaded grey are complete and will be removed for the next MAC meeting.

2. Recommendation

The MAC Secretariat recommends that the MAC notes the updates in the paper.

3. Process

Stakeholders may raise issues for consideration by the MAC at any time by sending an email to the MAC Secretariat at energymarkets@deed.wa.gov.au.

Stakeholders should submit issues for consideration by the MAC two weeks before a MAC meeting so that the MAC Secretariat can include the issue in the papers for the MAC meeting, which are circulated one week before the meeting.

Table 1 – Current MAC Working Groups			
Working Group	**Established**	**Status**	**Next steps**
WEM Procedures Content Review	2 May 2024 MAC Meeting	Open	EPWA is currently reviewing Priority 1 WEM Procedures
Capability Class 2 Technologies Review	24 July 2025 MAC Meeting	Open	Working Group meeting scheduled for 26 March 2026
Essential Systems Services Framework Review	2 May 2024 MAC Meeting	Open	Publication of Information Paper, including metrics for AEMO to assess the performance of the FCESS against the Frequency Operating Standards
AEMO Procedure Change	1 May 2017 MAC Meeting	Open	Ongoing Process
AEMO Major Projects	1 May 2025 MAC Meeting	Open	Ongoing Process
Power System Security and Reliability Standards	23 November 2023 MAC Meeting	Open	Western Power Consultation Paper – User Facility Standards for grid-forming and grid-following inverters paper public consultation closed on 6 February 2026
Wholesale Electricity Market Investment Certainty Review	20 July 2023 MAC Meeting	Open	Ongoing Process
Cost Allocation Review	14 December 2021 MAC Meeting	Finishing	Schedule 3 is the last schedule of the of the Wholesale Electricity Market Amendment (Cost Allocation Reform) Rules 2024 for which a commencement date is yet to be specified by the Minister.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**

Cost Allocation Review (CAR)	A review of:
	• the allocation of Market Fees, including behind the meter (BTM) and Distributed Energy Resources (DER) issues;
	• cost allocation for Essential System Services; and
	• Issues 2, 16, 23 and 35 from the MAC Issues List.
		• The MAC established the Cost Allocation Review Working Group (CARWG). Information on the CARWG is available at Cost Allocation Review Working Group, including:
		  • the Scope of Work for the review, as approved by the Coordinator;
		  • the Terms of Reference for the CARWG, as approved by the MAC;
		  • the list of CARWG members;
		  • meeting papers and minutes from the CARWG meetings on 9 May 2022, 7 June 2022, 30 August 2022, 27 September 2022, 25 October 2022, 29 November 2022, 21 March 2023, 2 May 2023 and 29 August 2023.
		• The following papers have been released and are available on the CAR webpage at Cost Allocation Review:
		  • the Consultation Paper;
		  • the International Review;
		  • submissions on the Consultation Paper;
		  • the CAR Information Paper;
		  • the Exposure Draft of the ESM Amending Rules implementing the outcomes of the CAR;
		  • submissions on the CAR ESM Amending Rules Exposure Draft; and
		  • response to submissions on the CAR ESM Amending Rules Exposure Draft.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**

		• the Wholesale Electricity Market Amendment (Cost Allocation Reform) Rules 2024 available at Wholesale Electricity Market Amendment (Cost Allocation Reform) Rules 2024.
		• Further changes to refine the cost allocation method for the Contingency Reserve Raise Service were presented at the 18 June 2024 TDOWG and consulted on within the Miscellaneous Amendments No. 3 Exposure Draft.
		• The last set of changes (to Contingency Reserve Raise cost allocation) implementing the outcomes of this Review were included in the Amending Rules made by the Minister on 2 October 2024.
		• AEMO to confirm implementation dates.
		• An Exposure Draft was released on 19 August 2025 on changes to Contingency Reserve Lower that affects Schedule 4 of the *Wholesale Electricity Market Amendment (Cost Allocation Reform) Rules 2024*.
		    • Consultation closed 2 September 2025.
		    • One stakeholder submission was received, which was published on 26 September 2025.
		• By gazettal on 26 September 2025, Schedules 2 and 4 of the *Wholesale Electricity Market Amendment (Cost Allocation Reform) Rules 2024* will commence on 30 October 2025.
		• Schedule 3 is the last schedule of the of the Wholesale Electricity Market Amendment (Cost Allocation Reform) Rules 2024 for which a commencement date is yet to be specified by the Minister.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**

Review of the Power System Security and Reliability (PSSR) Standards	The scope of this review is to:
	• review the various PSSR related provisions in the instruments governing power system security and reliability in the SWIS;
	• assess whether the combination of existing standards is effective to ensure power system security and reliability can be maintained;
	• develop proposals for a single end-to-end PSSR standard and a centralised governance framework; and
	draft amending Rules and other regulatory changes, as necessary.
		• The MAC established the PSSR Standards Working Group (PSSRSWG). Information on the PSSRWG is available at Power System Security and Reliability (PSSR) Standards Working Group including:
		  ◦ the Terms of Reference for the PSSRSWG, as approved by the MAC;
		  ◦ the Scope of Work
		  ◦ the list of PSSRSWG members; and
		  ◦ meeting papers and minutes for the 14 December 2023, 1 February 2024, 29 February 2024, 18 April 2024, 25 July 2024, 10 October 2024 and 31 October 2024 PSSRSWG meetings.
		• The PSSR Consultation Paper was published on 19 June 2025 on the PSSR Standards Review webpage.
		  ◦ The consultation period for the Consultation Paper closed on 7 August 2025.
		  ◦ Stakeholder submissions were published on 14 November 2025 on the PSSR Standards Review webpage.
		• The consultation period for Proposal 20 included in the PSSR Consultation Paper - Adopting Western Power September 2023 Proposed Technical Rules Amendments was extended on 30 September 2025.
		  ◦ The consultation period closed on 11 November 2025.
		  ◦ Stakeholder submissions were published on 13 August 2025.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
		• A Western Power Consultation Paper – User Facility Standards for grid-forming and grid-following inverters was published on 22 December 2025 on the PSSR Standards Review webpage. ◦ The consultation period for the Consultation Paper closes on 6 February 2026. • EPWA is currently progressing work on the following items, anticipated for publication in the first half of 2026: ◦ assessing options to propose a System Strength incentive framework, to be issued for stakeholder consultation. ◦ an Information Paper outlining the review outcomes covering interim GFM and GFL technical requirements and prescribed roles and responsibilities for system strength, together with an Exposure Draft of ESM Amending Rules.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
WEM Procedure Content Review	The scope of this review is to assess the content of selected existing WEM Procedures and their heads of power to determine, using the guiding principles, whether any matters identified require changes to improve the effectiveness of WEM Procedures, including, but not limited to: • the potential elevation of certain content to the ESM Rules; and/or • changes to a WEM Procedure heads of power.	• A revised Scope of Works and Terms of Reference was presented to the MAC at the 4 September 2025 Meeting to reflect the proposals from the 2025 WEM Operation Effectiveness Report. • On 11 September 2025, a MAC member provided EPWA with WEM Procedures that should be included in the review. • EPWA is currently reviewing Priority 1 WEM Procedures, as outlined in the Scope of Works.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Procedure Change Process (PCP) Review	A review of the PCP to address issues identified through Energy Policy WA's consultation on governance changes.	• The MAC discussed a draft Scope of Work for this review at its meeting on 11 October 2022. EPWA has updated the Scope of Works to reflect the MAC discussions. • The Scope of Work for the review, as approved by the Coordinator is available here Wholesale Electricity Market Procedure Change Process Review (www.wa.gov.au) • ACIL Allen has been appointed to assist with the PCP review. • ACIL Allen engaged with MAC members through a survey and one-on-one consultations between 12 March and 18 April 2024. There were 11 respondents to the PCP survey, out of 19 requests. • On 6 May 2024, the Consultation Paper was released for public consultation. Submissions closed 31 May 2024 with stakeholder submissions published on the Coordinator's website. • On 9 August 2024, the Coordinator finished stage 1 by publishing the ACIL Allen report and his response on the Coordinator's website. • EPWA is progressing stages 2 and 3 of the review and is revising a draft consultation paper to reflect the MAC's feedback from the 5 September 2024 MAC meeting.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Review of the Essential Systems Services (ESS) Framework	The Coordinator of Energy (Coordinator) is conducting a review of the ESS Framework (the Review), incorporating: • a review of the ESS Process and Standards under Section 3.15 of the ESM Rules; and • a review of the Supplementary Essential Systems Services Procurement Mechanism (SESSM) under clause 2.2D.1(h). The purpose of this Review is to assess whether the FCESS framework in the ESM Rules is operating efficiently to ensure power system security and reliability can be maintained at the lowest cost to consumer.	• The MAC approved the establishment of the ESS Framework Working Group (ESSFRWG) to support the ESS Framework Review. Information on the ESSFRWG is available at Essential System Services Framework Review Working Group including: • The Terms of Reference for the ESSFRWG, as approved by the MAC; • The list of ESSFRWG members; • Meeting papers and minutes for 6 November 2024, 26 February, 26 March and 24 July 2025 meetings. The following papers have been released and are available on the ESS Framework Review webpage: • The Scope of Work for the Review. • The Essential System Services Framework Review Consultation Paper. • An addendum (of proposed ESM Amending Rules) to the Essential System Services Framework Review – Consultation Paper • Stakeholder submissions to the Essential System Services Framework Review Consultation Paper and addendum. • The Amending Rules to relax the RoCoF Safe Limit were included in the Electricity System and Market Amendment (Tranche 9) Rules 2025 which were approved by the Minister for Energy on 19 December 2025, published in the Government Gazette on 23 December 2025 and will commence on 26 February 2026.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
		Next Step: EPWA to draft Information Paper.

WEM Investment Certainty (WIC) Review	The WIC Review will consider, design and implement the following five reforms that have been announced by the Minister for Energy, which are aimed at providing further investment certainty to assist the decarbonisation of the WEM:
	(1) changing the Reserve Capacity Price (RCP) curve so it sends sharper signals for investment when demand for new capacity is stronger;
	(2) a 10-year RCP guarantee for new technologies, such as long-duration storage;
	(3) a wholesale energy price guarantee for renewable generators, to top up their energy revenues as WEM prices start to decline, in return for them firming up their capacity;
	(4) emission thresholds for existing and new high emission technologies in the WEM; and
	(5) a 10-year exemption from the emissions thresholds for existing flexible gas plants that qualify to provide the new flexibility service.
		• The MAC established the WIC Review Working Group (WICRWG). Information on the WICRWG is available at [Wholesale Electricity Market Investment Certainty (WIC) Review Working Group] including:
		  • the Terms of Reference for the WICRWG, as approved by the MAC;
		  • the list of WICRWG members;
		  • meeting papers and minutes from the 31 August 2023, 11 October, 8 November, the 6 December 2023, 24 January, the 24 April and 29 May 2024 WICRWG meeting.
		• The following papers have been released and are available on the WIC Review [webpage], including:
		  • the Scope of Work for the review, as approved by the Coordinator;
		  • the WIC Review (Initiatives 1 and 2) Consultation Paper;
		  • the submissions received on the WIC Review (Initiatives 1 and 2) Consultation Paper;
		  • the WIC Review (Initiatives 1 and 2) Information Paper;
		  • The Exposure Draft of ESM Amending Rules to implement Initiatives 1 and 2;
		  • Submissions for the Exposure Draft of WEM Investment Certainty and RCM Review Amending Rules; and
		  • Response to Submissions for the Exposure Draft of WEM Investment Certainty and RCM Review Amending Rules.
		• The ESM Rules implementing the Review Outcomes for Initiatives 1 and 2 of the WIC Review are in Wholesale Electricity Market Amendment (RCM Reviews Sequencing) Rules 2025. The Rules were approved by the Minister for

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**

		Energy and published in the Government Gazette on 14 January 2025.
		• The WICRWG convened on 14 August 2025 to discuss the Coordinator's review of the Benchmark Capacity Providers.
		  • meeting papers and minutes for this meeting are available at Wholesale Electricity Market Investment Certainty (WIC) Review Working Group page.
		• The following papers for the 2025 Benchmark Capacity Provider Review have been released and are available on the webpage:
		  • Scope of Work
		  • Consultation Paper
		  • Stakeholder submissions
		  • The Coordinator's Determination, including responses to submissions

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Capability Class 2 Technologies Review (CC2TR)	The Review will consider: • whether market design changes are required to maintain Power System Security and Reliability (PSSR) with the growing share of Electric Storage Resource (ESR) in the South West Interconnected System (SWIS); • whether the methodology for rating the capacity of ESR for the purposes of setting Certified Reserve Capacity remains consistent with the State Electricity Objective (SEO); • whether the Demand Side Programme (DSP) Obligation Duration remains consistent with the SEO; and • whether the ESR obligation intervals (ESROI), including the effectiveness of the method used by AEMO to determine the ESROI, is consistent with the SEO.	• The MAC established the Capability Class 2 Technologies Review Working Group (CC2TRWG). Information on the CC2TRWG is available at Capability Class 2 Technologies Review Working Group, including: • the Terms of Reference for the CC2TRWG, as approved by the MAC; • the list of CC2TRWG members; • Meeting papers and minutes for the 23 October 2025, 4 December 2025 and 5 February 2026 CC2TRWG meeting; and • Meeting papers for the 26 March 2026 CC2TRWG meeting. • The following papers have been released and are available on the CC2TR webpage: • the Scope of Works.
Forecast quality	Review of Issue 9 from the MAC Issues List.	• This review has been incorporated in the Operational Forecasting Review.
Network Access Quantity (NAQ) Review	Assess the performance of the NAQ regime, including policy related to replacement capacity, and address issues identified during implementation of the Energy Transformation Strategy (ETS).	• The timing for this review is to be determined.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Short Term Energy Market (STEM) Review	Review the performance of the STEM to address issues identified during implementation of the ETS.	• This review has been deferred.

Table 3 – Other Issues			
Id	**Submitter/Date**	**Issue**	**Status**
9	Community Electricity November 2017	Improvement of AEMO forecasts of System Load; real-time and day-ahead.	EPWA has commenced work to improve AEMO's operational forecasting that will consider this issue. The following papers have been released and are available on the Operational Forecasting Review webpage: • The Scope of Works • The Operation Forecasting Review Consultation Paper • Stakeholder submissions EPWA is considering stakeholder feedback on the Consultation Paper and is preparing to release an Exposure Draft on proposed Amending Rules.

Department of
Energy and Economic Diversification

GOVERNMENT OF WESTERN AUSTRALIA

Energy Policy WA

Agenda Item 9: Overview of Rule Change Proposals (as of 12 March 2026)

Market Advisory Committee (MAC) Meeting 2026_03_19

- Changes to the report since the previous MAC meeting are shown in red font.
- The next steps and the timing for the next steps are provided for Rule Change Proposals that are currently being actively progressed by the Coordinator of Energy (**Coordinator**) or the Minister.

Rule Change Proposals Commenced since the Report presented at the last MAC Meeting

None

Rule Change Proposals Awaiting Commencement

None

Rule Change Proposals Rejected since Report presented at the last MAC Meeting

None

Rule Change Proposals Awaiting Approval by the Minister

None

Formally Submitted Rule Change Proposal

Reference	Submitted	Proponent	Title and Description	Urgency	Next Step	Commencement
RC_2025_01	15 October 2025	Bluewaters Power	Supplementary Reserve Capacity Amendments		Coordinator must publish the Final Rule Change Report by 17 March 2026	

Pre-Rule Change Proposals

None

Rule Changes Made by the Minister since Report presented at the 11 February 2026 MAC Meeting

Rule Change Made by the Minister and Awaiting Commencement

Gazette	Date	Title	Commencement
2024/66	7/06/2024	Wholesale Electricity Market Amendment (Cost Allocation Reform) Rules 2024	• Schedule 3 will commence at a time specified by the Minister in a notice published in the Gazette.
2025/113	26/09/2025	Wholesale Electricity Market Amendment (Supplementary Capacity No. 3) Rules 2024	• Schedule 2 will commence on 1 October 2026.
2025/3	14/01/2025	Wholesale Electricity Market Amendment (RCM Reviews Sequencing) Rules 2025	• Schedule 3 will commence 1 October 2026. • Schedule 4 will commence 1 October 2027. • Schedule 5 will commence 1 April 2026. • Schedule 6 will commence immediately after the commencement of the amending rules in Schedule 5 of the Electricity System and Market Amendment (Tranche 8) Rules 2025. • Schedule 7 will commence at a time specified by the Minister in a notice published in the Gazette.
2025/64	3/06/2025	Electricity System and Market Amendment (Tranche 8) Rules 2025	• Schedule 4 will commence 1 October 2026. • Schedule 5 will commence 1 October 2027. • Schedule 8 will commence

			immediately after the commencement of the amending rules in Schedule 2 of the Wholesale Electricity Market Amendment (Supplementary Capacity No. 3) Rules 2024. • Schedule 9 will commence at a time specified by the Minister in a notice published in the Gazette.
2025/155	23/12/2025	Electricity System and Market Amendment (Tranche 9) Rules 2025	• Schedule 2 will commence on 1 April 2026 • Schedule 2A will commence on 1 July 2026 • Schedule 3 will commence on 1 October 2026 • Schedule 4 will commence on 1 October 2027 • Schedule 5 will commence on 1 May 2026