Meeting Agenda

Meeting Title:	Capability Class 2 Technologies (CC2T) Review Working Group
Date:	Thursday 23 April 2026
Time:	11:00 AM – 12:30 AM
Location:	Online

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda • Competition Law	Chair	Noting	1 min
2	Meeting Apologies/Attendance	Chair	Noting	1 min
3	Minutes of Meeting 2026_03_26 At the time these papers were sent, this item was already with members for approval.	Chair	Noting	1 min
4	Minutes of Meeting 2026_04_02	Chair	Decision	4 min
5	Action Items	Chair	Noting	2 min
6	Policy Positions	RBP/EPWA	Discussion	80 min
7	General Business	Chair	Discussion	1 min

Please note, this meeting will be recorded.

Competition and Consumer Law Obligations

Members of the Working Group (**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.

Department of Energy and Economic Diversification
GOVERNMENT OF WESTERN AUSTRALIA

Energy Policy WA

Agenda Item 4: Capability Class 2 Technologies (CC2T) Review Working Group - Minutes

Date:	2 April 2026
Time:	9:30 AM – 10:24 AM
Location:	Microsoft Teams online

Attendees	Representing	Comment
Dora Guzeleva	Chair	
Natalia Kostecki	Australian Energy Market Operator (AEMO)	
Rebecca Pedlow-Collins	AEMO	
Francis Ip	BLT Energy	
Jake Flynn	Collgar Renewables	
Alister Alford	Enel X	
Richard Cheng	Economic Regulation Authority (ERA)	
Noel Schubert	Expert Consumer Panel	
Bobby Ditric	NewGen Power Kwinana	
Tessa Liddelow	Shell	Proxy for Sumeet Kaur
Graeme Ross	Simcoa	Invited by the Chair
Katherine Lau	Synergy	Proxy for Rhiannon Bedola
Darren Gladman	SMA	
Peter Huxtable	Water Corporation	
Paul Jones	Western Power	
Other attendees	**From**	**Comment**
Richard Bowmaker	Robinson Bowmaker and Paul (RBP)	Consultant appointed to assist with this review
Eija Samson	RBP	
Sean McAvoy	Energy Policy WA (EPWA)	Secretariat
Luke Commins	EPWA	Secretariat
Apologies		
Oscar Carlberg	Alinta	
Warren King	Frontier Energy	

Clement Ng	IGO	
Dale Waterson	Merredin Energy	
Max Collins	Neoen	
Patrick Peake	Perth Energy	
Sumeet Kaur	Shell	
Rhiannon Beola	Synergy	
Kaavya Jha	Tesla Motors	

1. WELCOME

The Chair opened the meeting with an Acknowledgement of Country.

The Chair noted the Competition and Consumer Law Obligations of the Working Group members.

The Chair apologised for sending incorrect slides in the lead up to the meeting, noting that the aim of this meeting is to finalise the Demand Side Programme (DSP) issues.

2. MEETING APOLOGIES AND ATTENDANCE

The Chair noted the attendance as listed above.

3. DSP AVAILABILITY OPTION

The Chair explained that during discussion on the DSP availability options at the 19 March 2026 Market Advisory Committee (MAC) meeting, the issue that large industrial loads would need to be offline for 16 hours to achieve the split window due to restart limitations was raised.

The Chair noted that:

- AEMO procured supplementary capacity (SC) for the 2025/26 Hot Season because modelling showed Unserved Energy after 8:00 pm once DSPs' availability obligation intervals end;
- an Electricity System and Market (ESM) Rule change to split the DSP window has already been made to cover both morning and evening peaks, yet to commence;
- current analysis shows that while the morning is less critical, allowing providers to choose only one window erodes DSPs reliability contribution; and
- it is infeasible to derate Capacity Credits.

The Chair presented Slides 1 to 4.

In response to Mr Schubert, the Chair noted that the time on Slide 1 was incorrect and it should read 2:00pm to 10:00pm rather than 2:00pm to6:00 pm. She advised that this will be corrected and the CC2TRWG meeting papers will be republished.

In response to Mr Ditric, the Chair confirmed that DSP availability remains at 12 hours. However, some MAC members pointed out that due to restart limitations, some large loads must stay offline for 16 hours, if activated for the morning window, to ensure that they are available for both windows.

The Chair presented Slide 5 and clarified that, although shifting the morning window would leave only a two-hour gap between the morning and evening windows, the proposal is still expected to deliver benefits, due to:

- DSP participants' ability to associate different loads to the morning and the evening windows;
- the analysis indicating a low likelihood of a DSP being called between 6:00 am and 8:00 am;
- extending the evening window reduces costs for consumers by avoiding future procurement of SC; and
- lower implementation costs for AEMO.

In response to Ms Pedlow-Collins, the Chair clarified that the proposed DSP options available to Market Participants are:

- 8:00am to 12:00pm and 2:00pm to 10:00 pm; or
- 2:00pm to 10:00pm only.

- Mr Ross supported the proposal as it addresses the issue that industrial large loads cannot restart in the hours between the end of the morning window and start of the evening window, if they have been activated in the morning.
- Mr Huxtable supported the proposal.
- Mr Alford supported the shifting of the morning window and sought clarity on whether DSPs at the same Transmission Node Identifier (TNI) would be treated as different facilities if they were certified for different windows, e.g., both the morning and the evening window versus only the evening window.

The Chair responded that the DSPs will be treated as separate facilities because each one would receive a different Reserve Capacity Price under the proposal.

- Mr Ditric supported the proposal and asked whether anything has been implemented to rotate DSP activation to prevent the same DSP facility from being called consistently.

The Chair responded that:

- a DSP rotation order was implemented into the ESM Rules following the Demand Side Response Review;
- currently, two DSPs also serve as Interruptible Loads for Contingency Reserve Raise Services and, therefore, the third DSP is called upon more frequently; and
- until the morning period becomes more of an issue this does not warrant a rule change. However, working group members are encouraged to reach with alternative suggestions.

- Mr Schubert noted that it was a pragmatic solution but questioned:
  - how 14 hours was preferable to 16 hours for large industrial loads; and
  - whether there was any benefit in adjusting the window, for example, extending the evening period to 11:00 pm given that the morning is less critical.
- Mr Ross responded to Mr Shubert and clarified that the issue was not the total number of hours, but rather the need to give large industrial loads flexibility in choosing their DSP windows.

The Chair clarified that the total 12-hour availability requirement for DSPs would remain unchanged, as altering it would be detrimental to incentivising the participation of DSPs. However, the Chair noted that the ongoing energy transition is causing many changes across the system and that reasonable changes to the DSP availability windows are welcomed.

- Ms Lau asked whether there would be a different trading mechanism for the DSPs that choose only the evening window.
- Mr Ditric noted that, under the previous arrangement when DSP had a separate Reserve Capacity Price, Market Participants were unable to allocate that capacity toward their Individual Reserve Capacity Requirement (IRCR). He asked whether the same limitation would apply under the current proposal.

The Chair noted that:

- the Capacity Credits are unchanged and only the Reserve Capacity Price is being derated; and
- a Transitional Peak Reserve Capacity Price mechanism already allows for the trading Capacity Credits with different RCP and it is expected that this DSP proposal would operate in a similar manner.

4. MECHANISM TO IMPROVE THE RESILIENCE OF DSP

Mr Alford noted that:

- the Reserve Capacity Mechanism (RCM) is the efficient method to bring flexible demand into the system;
- SC is a backstop mechanism, used when other mechanisms are not delivering what the system needs;
- an issue in the current DSP framework is that there is limited flexibility to find a replacement load when the one set up as a DSP closes due to external economic conditions, such as a mine going into care and maintenance; and
- the inflexibility leads to the DSP paying refunds to the WEM and is likely to lead to AEMO procuring SC.

Mr Alford proposed that when a DSP fails, the responsible Market Participant should be permitted to replace it with another DSP located on an unconstrained section of the network before the start of the relevant capacity year. He sought feedback on this proposal from the members.

The Chair noted that:

- this applies to a single load above five megawatts (MW) that has already completed the Reserve Capacity Certification process, and would only occur after the publication of unconstrained TNIs in January; and
- if this were to happen, the Market Participant should be required to notify AEMO before the WEM Electricity Statement of Opportunities (ESOO) is released, to ensure that the load is not included in the Reserve Capacity Target.

Mr Alford responded that Enel X already provides AEMO with ongoing commentary on its DSPs, so any new obligation would be consistent with current practice.

- Mr Schubert supported the proposal, noting that it gives DSPs the flexibility to substitute loads to meet their capacity obligations, which will provide a benefit to the overall system reliability.

The Chair clarified that this proposal does not affect the aggregated DSPs, which already provides the flexibility needed to align the association of loads to the DSP's Capacity Credits close to the start of the Capacity Year.

- Ms Pedlow-Collins noted that AEMO determines Network Access Quantities (NAQ) based on the National Metering Identifier (NMI) of the single load DSPs. Therefore, if the DSP's location changes, this can affect the NAQ and, in turn, have broader implications for the constrained equations derived from it.

The Chair noted that the exit of the load that the DSP intended to use would also affect the NAQ process to determine the constrained TNIs. The Chair noted that NAQ processes must be considered and asked Mr Alford to comment on his discussions with AEMO regarding the proposal.

Mr Alford explained that the proposal aims to follow the same process AEMO uses for SC, where AEMO intends to rely on unconstrained sections of the network in the future. He noted that discussions with AEMO are still ongoing and that opportunities to improve transparency around these unconstrained network sections could be included.

- Mr Huxtable questioned the need for an additional 5 MW capacity when a 5 MW load is exiting the system.
- Mr Schubert agreed with Mr Huxtable as exiting load above 5 MW would permanently lower system demand.

The Chair noted that only a significant load exiting the system would have a material impact on the overall system peak demand.

The Chair asked whether there would be any issue with returning the Security Deposit to a DSP when such a load leaves the system, provided the DSP has notified AEMO before the ESOO.

Mr Alford stated that:

- Enel X would be willing to receive back the Security Deposit in this scenario;
- doing so would reduce the risk Enel X considers when deciding which electricity market to participate in; and
- but if demand growth is underestimated, it is preferable to have the capacity available on the system.

The Chair noted that, given the dynamic nature of the WEM, it must be recognised that some loads intending to participate two years in advance may ultimately not be operational when that time arrives.

5. GENERAL BUSINESS

The Chair thanked members for their contributions and closed the meeting.

The meeting closed at 10:24am.

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Agenda Item 5: Action Items

CC2TRWG Meeting 2026_04_23

Shaded	Shaded action items are actions that have been completed since the last meeting. Updates from last 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 an explanation of the reasons for the price spike on 23 January 2025.	AEMO	2026_03_26	**Closed**

Not forecasted; primarily due to Forced Outages impacting the Network as a result of transmission line trips. Additionally, a double contingency of the ST-BTY81 and ST-EP82 transmission lines was identified due to bushfires in the area. Both of these resulted in the constraining of Facilities in the Kwinana area restricting available capacity.

Low wind, partly cloudy and 38 degrees max temp on the day.

Lower DPV than forecast meant higher than Forecast Unscheduled Operational Demand (FUOD). Note that DPV was lower than normal for January specifically due to Tropical Cyclone Sean.

Most facilities bidding at In-Service were trapped at their FCESS Trapezium or dispatched, and all other facilities were bid as Available during the price spike. This was likely driven by the large change in the FUOD compared to earlier in the day.

LOR was issued at 13:00 as demand was around 3500 MW and expected to reach around 4300 MWs; the actuals show that DPV kept demand down to around 4000 MW as DPV subsequently picked-up. Ultimately the highest demand was seen around 17:30-19:30.

Item	Action	Responsibility	Meeting Arising	Status
2/2026	AEMO to provide an explanation of the reasons for not issuing a direction on 9 February 2026.	AEMO	2026_03_26	**Closed**
	On the day, system reserves were assessed as being relatively high and there were no indications of a material event or emerging shortfall during the peak period. It was forecast to be a hot day, the wind was low after midday. Consequently, AEMO contacted both ESR facilities with a precautionary reminder of their ESROI peak period obligations. Due to the presence of reserves, a formal direction (intervention) was not issued; noting that AEMO endeavours to minimise its interventions. After the reminder, there was a significant increase in ESR charging from about 1500 hrs. The actuals demand shows that demand peaked significantly lower than forecast and also earlier than forecast (following the cautionary reminders).			
3/2026	AEMO to provide an estimate of the implementation costs associated with an additional refund mechanism.	AEMO	2026_03_26	**Open**
4/2026	EPWA to confirm whether the ERA recovers its civil penalty proceedings from the WEM	EPWA	2026_03_26	**Closed** Under the ESM Rules, the ERA recovers the costs of performing its functions — including surveillance and enforcement — through Regulator Fees, which are passed on to Market Participants.

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Energy Policy WA

Capability Class 2 Technologies (CC2T) Review

- Recap of settled positions
- Settling final outstanding positions

23 April 2026

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

Agenda

1.0	Recap of scope and settled policy positions
1.1	Scope and context of review
1.2	Settled position 1: Approach for allocating capacity to ESRs
1.3	Settled position 2: Reserve Capacity testing change for ESRs
1.4	Settled position 3: Existing refund regime
1.5	Settled position 4: Mandated State of Charge Obligations for ESR triggered by LOR declarations (see below for principles)
1.6	Settled position 5: DSP Availability Window
1.7	Settled position 6: Capability Class 2 split for NAQ tie-breaking
1.8	Settled position 7: Return of Reserve Capacity Security to DSPs if their (>5MW) Associated Load exits
2.0	Policy positions to discuss
2.1	Policy principles underpinning mandatory State of Charge Obligations
2.2	Additional charge shortfall refund to apply during Low Reserve Condition
3.0	Issues identified but determined to be out of scope

Recap

Scope and settled policy positions

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 necessary to maintain security and reliability
- Both ESR and DSPs are treated as duration/energy limited technologies in the ESM Rules:
  - Certification approach must reasonably estimate reliability contribution.
  - Availability obligations must be aligned to power system need and times when non-CC2 capacity is insufficient to meet demand.

Scope item	Settled
Issue 1: Review whether current ESR certification methodology (Linearly De-rating Method) is still aligned with SEO.	✓
Issue 2: Review Reserve Capacity Refunds regime and evaluate potential to sharpen availability incentives	✓
Issue 3: Review DSP availability obligations against SEO	✓
Technical Analysis – current-state analysis	**Complete**
Technical Analysis – future state analysis	**Complete**
Issue 4: Identify policy options to improve ESR availability (based on Technical Analysis)	**× Two outstanding items: Policy principles underpinning SOC obligations and additional charge shortfall refund**
Issue 5: Assess whether existing Capability Class 2 should be split for NAQ prioritisation	✓

Policy options developed 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

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

Settled position 1: Approach for allocating capacity to ESRs [15]

Working Group has reviewed four options (including status quo)

- ESR derating approach needed to reflect duration limited nature of ESR.
- Existing WEM approach is simple and transparent.
- WG has reviewed status quo and three variants of the Effective Load Carry Capability (ELCC) approach.

Option	Description
Status Quo	Linear Derating Methodology (degraded maximum charge capability by the relevant ESROD value) • Incumbent batteries retain the original ESROD for ten years; and • Over-allocation of capacity to incumbent batteries is added back into the Planning Criterion.
Option 1: Incorporate storage into amended RLM	Incorporate ESR into the amended Appendix 9 (Last-in Fleet ELCC) (adopting same approach as for CC3).
Option 2: Implement individual ELCCs	Per Option 1, however, implement individual ELCCs for both ESR and CC3. Requires replacing amended Appendix 9 which uses Fleet ELCCs so that all intermittent generation and storage is allocated individual ELCCs
Option 3: Option 1 with least-worst regrets analysis	Same as Option 1 but replace demand scenarios with least worst regrets analysis. (This calculates ELCCs for multiple demand scenarios and capacity adequate portfolios and selecting the results of the demand scenario that minimises the worst regret cost)

Settled position 1: Approach for allocating capacity to ESRs

CC2TRWG indicated preference to retain status quo (LDM and ESROD)

- Status quo performs the best due to simplicity and certainty of allocations.
- Alternatives have more sophisticated approach to measuring marginal reliability impact but introduces uncertainty of capacity allocation and are complex to implement as evidenced by international experience.
- CC2TRWG has also indicated preference to retain nomination approach to allocating DSP capacity (instead of using ELCC approach).

	Status Quo (LDM & ESROD)	Option 1: Fleet ELCC	Option 2: Individual ELCC	Option 3: Fleet ELCC with least worst regrets
Overall performance				
Provides value for money by reasonably approximating contribution of batteries to reliability	Met partially	Met substantially	Met partially	Fully met
Method is transparent and predictable	Met substantially	Not met	Not met	Not met
Method does not result in volatile allocation from year to year	Met substantially	Met partially	Not met	Met partially
Cost and complexity of implementation is reasonable	Fully met	Met partially	Not met	Not met

See Annex 1 for detailed evaluation

Settled position 2: RC Testing changes for ESR

Working Group has agreed to rule amendment to fix ESR RC Testing Issue

Two further issues discussed:

- **Participants indicating 0% minimum charge levels will be over-allocated capacity:**
  - Rules already indicate that Linearly Derating Capacity must reflect what ESR is actually capable of delivering.
  - CC2TRWG agreed that no rule changes are needed; AEMO can make changes to the WEM Certification Procedure to clarify the requirements.
- **Reserve Capacity Testing rules do not account for ESR ramping:**
  - ESR uses energy when ramping to its Required Level and then when ramping down to its minimum discharge depth.
  - Average performance during the testing intervals will therefore not deliver the ESR's Required Level and will result in failed test.
  - CC2TRWG agreed to proposed amendment to ESMR 4.25.2E to assess test performance using "area under curve" which includes energy produced during ramping.

See Annex 2 for a more detailed description of these issues

Settled position 3: Existing refund regime

Working Group has agreed existing refund regime is fit for purpose and should not be changed significantly

- WG has indicated preference to retain existing refund regime as is.
  - Increasing Dynamic Refund Factor cap across the board may result in participants inflating offers to manage financial exposure.
- WG noted that changing refund regime parameters is unlikely to affect charging behaviour.
- Some noted that it was unreasonable for ESR to enter their ESROI with low State of Charge (SOC) but not incur refunds until they are out of charge.
  - See later slides on option for additional charge shortfall refund.
- Instead, focus should be on identifying system conditions in which triggers can be used to mandate SOC obligations on ESRs:
  - See settled position 4 and later slides on policy principles underpinning SOC obligations.
  - See slides on additional refund to apply during SOC mandate intervals – propose minor change to existing refund regime to only apply when AEMO invokes SOC mandate.

Settled position 4: Mandated State of Charge Obligations

Policy issue relates to improving the availability of ESRs, so they are available to meet reliability needs

To explore this issue, two questions were asked:

1. When are ESRs expected to be used to avoid load shedding?
2. Does the RCM ensure ESRs have sufficient charge prior to entering their ESROIs?

Two-stage Technical Analysis informed the above:

- Current State Analysis: A review of historical System Stress Events (SSEs) to understand timing and duration of SSEs and system conditions when these events occur.
- Future State Analysis: AEMO modelling of Capacity Years 2026 – 2030 to forecast when ESRs are likely to be needed to avoid unserved energy.
    - Model dispatches ESR to avoid unserved energy (vs restricting discharge to ESROIs).
    - Since the draft analysis, 4 Additional reference years were included but did not materially change the results.

See Annex 3a and 3b for abridged Technical Analysis slides

Settled position 4: Mandated State of Charge Obligations

For SSEs, ESRs are mostly needed during the evening peak period, plus occasional earlier periods

- Current State Analysis identified 26 SSEs from Oct 2023 to Aug 2025
  - SSEs typically occur during summer evenings and are largely driven by extreme temperatures.
  - Low wind and scheduled outages can also contribute to system stress during summer.
- Of the 26 events:
  - 19 commenced prior to 16:30 (start of incumbent ESROIs).
  - 9 of the 19 events started at 16:00 (only 30 mins earlier).
  - 4 of the 19 events started prior to 16:00 with <50MW of ESROI capacity on system – when CC1 & CC3 were more important in maintaining reliability.
  - 6 of the 19 events occurred **after November 2024** (FCESS Cost Review ESM Rule Changes) and they **all started before 16:30**. However, highest stress time occurred around mid-Peak ESROI.

SSE date	Start	End	Peak demand time	Highest stress time*
10/12/2024	15:00	20:30	18:35	18:35
11/12/2024	15:00	20:30	18:35	18:35
20/01/2025	15:00	20:30	18:35	18:35
21/01/2025	11:25	20:30	18:00	17:50
23/01/2025	13:00	20:30	18:45	18:50
6/03/2025	15:00	22:00	18:00	18:20

*Time at which the capacity margin was the tightest

Settled position 4: Mandated State of Charge Obligations

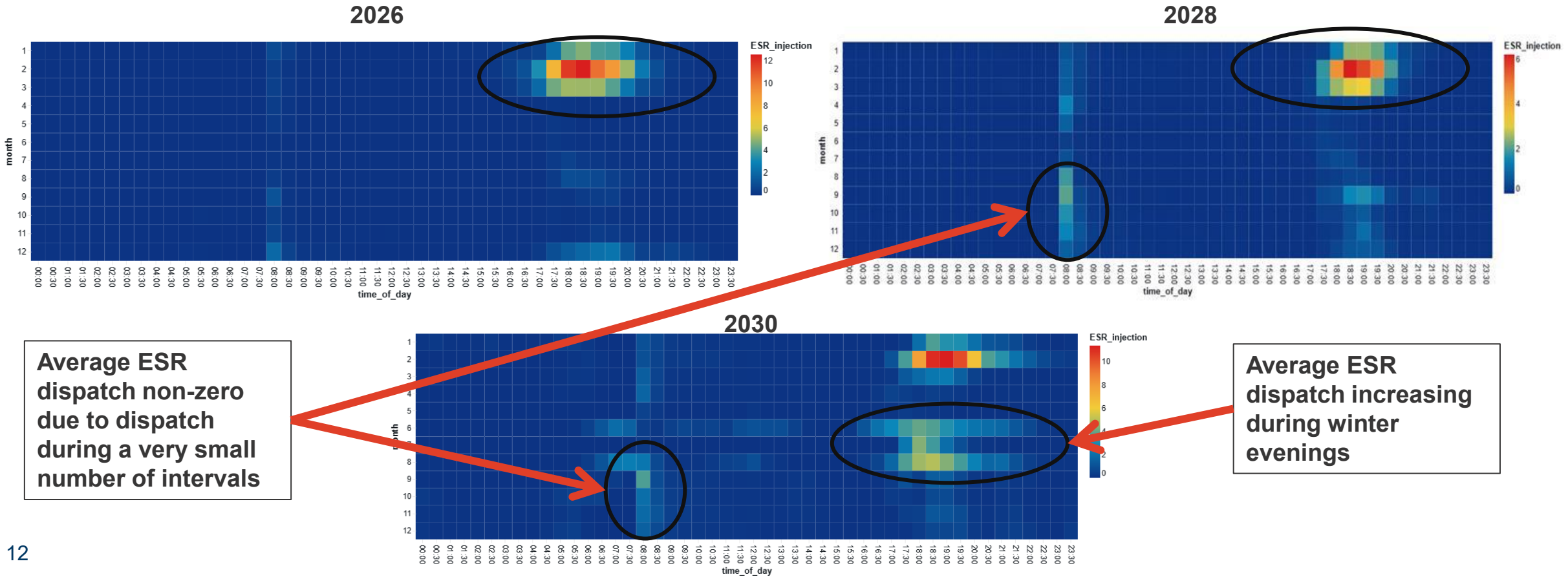
ESRs likely to be needed during evening peak period through to 2030.

Future state modelling finds that ESRs are required during evening summer peaks; less during winter evenings.

- The below results are inclusive of the additional 4 reference years.

In 2030, there is greater ESR injection during winter peaks more likely to need ESR in winter evenings in the future.

Insufficient evidence to find ESR will be needed during the mornings.



Settled position 4: Mandated State of Charge Obligations

The current availability period is currently fit for purpose

- Current and future state analysis finds that ESR availability is most required during the evening peak period till 2030:
  - Post 2030 modelling has insufficient capacity to draw robust findings.
- Future state analysis shows a small amounts of average ESR injection during winter mornings around 8am.
  - Not reliable as these averages are based on a very small number of iterations.
- Conclude that the existing approach to determining ESROD/ESROIs is currently fit for purpose.

No changes required to existing ESROD/ADG approach in the short-term.

See Annex 3a and 3b for abridged Technical Analysis slides

Settled position 4: Mandated State of Charge Obligations

Existing refund regime on its own may not ensure ESRs are sufficiently charged during SSEs

Current State Analysis examined subset of SSEs where ESRs had low SOC entering their ESROIs.

- 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.
  - The same high energy price issue was experienced for the 25 August 2025 event.
- For subset of five 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.

Working Group has agreed AEMO requires mandate to place State of Charge obligations on ESR for PSSR purposes

Settled position 4: Mandated State of Charge Obligations

WG has agreed to AEMO using LOR to trigger a SOC obligation

Working Group has agreed:

- AEMO should be able to use a Lack of Reserve (LOR) declaration to mandate SOC obligations for ESR.
  - Assuming that AEMO's forecasts will be sufficiently accurate .
- Obligations should not require 100% SOC as default – the SOC will be determined by AEMO based on prevailing system conditions.
- ESM Rules should empower a WEM Procedure that sets out the details of how SOC obligations will work.
- Details to be provided in the WEM Procedure, but principles governing the regime, including the trigger, and the requirement for the content of the WEM Procedure must be specified in the ESM Rules.

Settled position 5: DSP Availability Window

Recap of policy problem

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.
- Current State Analysis indicated that 15 out of 26 SSEs ended after 8pm.
- Review of DSP availability obligations needed to ensure these align with system need and that current settings do not result in increased emergency procurement.

Residential Battery Scheme has resulted in large uptake of BTM batteries

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

Settled position 5: DSP Availability Window

Three options originally assessed – preferred (split-window) option further assessed

- Option 1: split window option (Tranche 8):
  - 6am-10am and 2-10pm
- Option 2: DSPs rolled into ESROD.
- Option 3: DSP availability based on Peak DSP Dispatch Requirement.
- Option 1 performs best against SEO:
  - Retains 12-hour requirement;
  - Performs better against reliability limb if only split window option is available;
  - Simple to implement.
- Option 2 and 3 will dilute value provided by DSPs and is more complex to implement.
- Option 1 preferred, but had some issues:
  - Morning window problematic for BTM batteries as their charge will likely be depleted;
  - Large loads have re-start limitations meaning they effectively have to be available from 6am – 10pm;
  - Morning window spans two Trading Days – implementation complexity.

	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 Annex 4 for evaluation of DSP options presented at Feb 2026 meeting

Settled position 5: DSP Availability Window

Working Group supports variant to Option 1 to address raised issues

Variant to Option 1

- DSP can choose one of two options:
  - Be available during two split windows: 8am – 12pm and 2pm – 10pm on Business Days; OR
  - Only be available from 2pm-10pm on Business Days.

  DSPs cannot offer availability outside these windows to simplify implementation – this will involve ESM Rule changes.
- Morning window shifted to 8am to prevent Trading Day cross-over and reduce implementation costs.
  - Current State Analysis included one SSE that commenced between 8am-12pm.
- DSPs choosing evening window only receive a derated Reserve Capacity Price that flows to their Reserve Capacity Security requirement.
- There may be issues with treating Capacity Credits assigned to DSPs who opt for the evening window as equivalent to other Capacity Credits, and there is an option to require these to be traded through AEMO.
  - This would require changes to section 4.28 of the ESMR.

Settled position 6: DSP consequential amendments

Consequential amendments needed so over-subscribed DSPs can specify which Associated Loads will be activated

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 while 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.
- Working Group supports amendments to require DSP to associate loads at least three weeks prior to effective date:
    - DSPs have opportunity to use different loads for different events but cannot game the Relevant Demand baseline.
    - Any DSPs can nominate different loads for different windows. For example, a 10MW DSP can associate different loads for the morning versus evening window.

Question: Should a DSP be able to nominate, at the same time, different loads for different days?

Settled position 7: Return of DSP security if load exits

DSP ability to source replacement load if large (>5MW) Associated Load exits

- Working Group noted that if a large Associated Load exits or goes on prolonged maintenance before the start of the relevant Capacity Year, the DSP cannot recruit another similar load at a different TNI to meet their obligations.
- Working Group discussed the potential of allowing a DSP to associate a replacement a new large load at a TNI, as long as it is deemed unconstrained by AEMO under ESMR 4.15.16A.
    - AEMO raised a concern that this could adversely affect the NAQs of other facilities.
    - An exiting load reduces overall system demand which reduces the need for “replacement” capacity .
- Working Group discussed the following approach:
    - A DSP participant who has reason to believe their (>5MW) Associated Load may exit for an extended period during the relevant Capacity Year must notify AEMO by April 1st Year 3 (prior to ESOO development) to enable AEMO to model the impact of the load exiting on the Reserve Capacity Requirements.
    - If the DSP does this then it may request a reduction in Capacity Credits and the return of their Reserve Capacity Security (as the exiting load capacity no longer needs to be served).
    - Any Associated Load that has exited and been removed from a DSP’s portfolio cannot participate in a Supplementary Capacity procurement for the upcoming Capacity Year.

For avoidance of doubt, this policy position does <u>not</u> apply to DSPs covered under ESMR 4.10.1B

Settled position 8: Capability Class 2 split

Proposal to split CC2 into subclasses on hold – area for observation

- Proposal to split CC2 class into subclasses:
  - CC2(a): Facility with Separately Certified Components (SCC) that is over 50% CC2 (i.e. ESR hybrid).
  - CC2(b): Pure ESR Facility.
  - CC2(c): Pure DSP Facility.
- Proposal was to revise NAQ prioritisation order for tie-breaking so that hybrids are prioritised over pure ESR, and pure ESR is prioritised over pure DSPs.
- Working Group noted it was unclear whether a policy problem currently exists that would justify implementation cost of this approach.
- The proposed order may need to be re-examined to determine if pure DSP should be higher than pure ESR in the event of a CC1 and CC3 shortfall.
- Working Group preference is to not progress this change – but watch this area for future issues.

Capability Class acts as the first tie-breaker to decide which Facility is assigned NAQs first (if within the same step), in order of:

1. Capability Class 1 Facilities
2. Capability Class 3 Facilities
3. Capability Class 2 Facilities

If Capability Class 2 is split, the revised order could become:

1. Capability Class 1 Facilities
2. Capability Class 3 Facilities
3. Capability Class 2(a) Facilities (Hybrids)
4. Capability Class 2(b) Facilities (Pure ESR)
5. Capability Class 2(c) Facilities (Pure DSP)

Policy positions yet to be confirmed

1. Principles governing SOC mandate regime
2. Additional Charge Shortfall Refund to apply during SOC mandate intervals

Policy principles governing mandatory SOC Obligations

Technical analysis indicated existing refunds alone do not ensure adequate SOC for the ESROIs

Working Group has supported:

- AEMO should be able to use a Lack of Reserve (LOR) declaration to mandate minimum SOC obligations for ESR.
  - Assumes that AEMO's forecasts will be sufficiently accurate.
- SOC obligations should be able to change, with the required charge level determined by prevailing system conditions instead of a fixed 100% default.
- ESMR should:
  - empower a WEM Procedure that sets out the details of how SOC obligations will work; and
  - specify the trigger of when it applies.
- Principles governing the regime and the contents of the WEM Procedure must be specified in the ESM Rules.
- WEM Procedure must address:
  - Notification period – ESR operators require lead-time to ensure they can revise operational plans and offers. Declaration can be revoked if circumstances change but otherwise requirements cannot change after 8am on the relevant Trading Day ; and
  - Transparent methodology for determine fleet SOC required and individual SOC required.

Does the CC2TRWG have any comments on what else the WEM Procedure should address?

Type	Trigger conditions	Description
LOR1	Forecast Available Capacity is greater than the Forecast Operational Demand plus 70% of the Largest Supply Contingency, but less than the Forecast Operational Demand plus 100% of the Largest Supply Contingency plus 70% of the Second Largest Supply Contingency	Probability of load shedding low, but risk of ESS shortfalls are elevated
LOR2	Forecast Available Capacity is greater than the Forecast Operational Demand plus the Operational Reserve Margin, but less than the Forecast Operational Demand plus 70% of the Largest Supply Contingency	Probability of load shedding is elevated and there is insufficient ESS
LOR3	Forecast Available Capacity is less than the Forecast Operational Demand plus the Operational Reserve Margin	Insufficient capacity to avoid load shedding and meet ESS requirements

Policy principles governing mandatory SOC Obligations

Summary of proposed principles

Trigger

- AEMO to invoke SOC mandate if LOR declaration applies during ESR Obligation Intervals – new LOR condition to be developed.
- AEMO will use existing probabilistic framework used in Low Reserve Conditions monitoring to deem the probability of a LOR condition manifesting.
- Use of POE forecasts mean participants will know the probability of that forecast eventuating – provides greater certainty.

Notification Period

- AEMO must use best endeavours to declare SOC mandate by 8pm on Scheduling Day; otherwise
- AEMO must declare the SOC mandate by no later than 8am on Trading Day.

SOC mandate

- AEMO will determine a single SOC percentage to apply to the entire fleet at the start of the ESROI that is part of the LOR declaration so that each ESR gets the same SOC requirement at the beginning of their ESROD.
- AEMO may withdraw the SOC mandate if it deems the LOR condition is no longer likely to manifest.

Other considerations

- AEMO will be empowered to require ESR charging when a SOC mandate is declared to potentially stagger charging to maintain PSSR (instead of using Chapter 3 provisions).
- Approach and methodology should be simple, but provide sufficient certainty to participants, and minimise disruption to normal market processes.

Policy principles governing mandatory SOC Obligations

Trigger

- Three types of Low Reserve Declaration – only LOR2 and LOR3 indicate actual or possible energy shortfalls.
  - LOR1 – LOR3 conditions indicate risk to PSSR due to uncontrollable contingencies (network or generator trip, uncertainty in weather patterns, etc.).
  - Does not provide insight on system risk if one or more ESRs fail to reach sufficient charge to meet their RCOQs.
- Propose creation of a "**LOR-SOC**" condition that indicates heightened system risk if ESR fleet is not at a certain level of charge during the upcoming ESROIs:
  - LOR1 – LOR3 conditions indicate low reserve assuming available ESRs will be able to provide RCOQ during ESROIs.
  - LOR-SOC will pick up where LOR1-LOR3 conditions may manifest due to insufficient ESR fleet charge.
  - If there is a LOR1-3 condition, a LOR-SOC condition will apply automatically – converse does not apply.

Questions

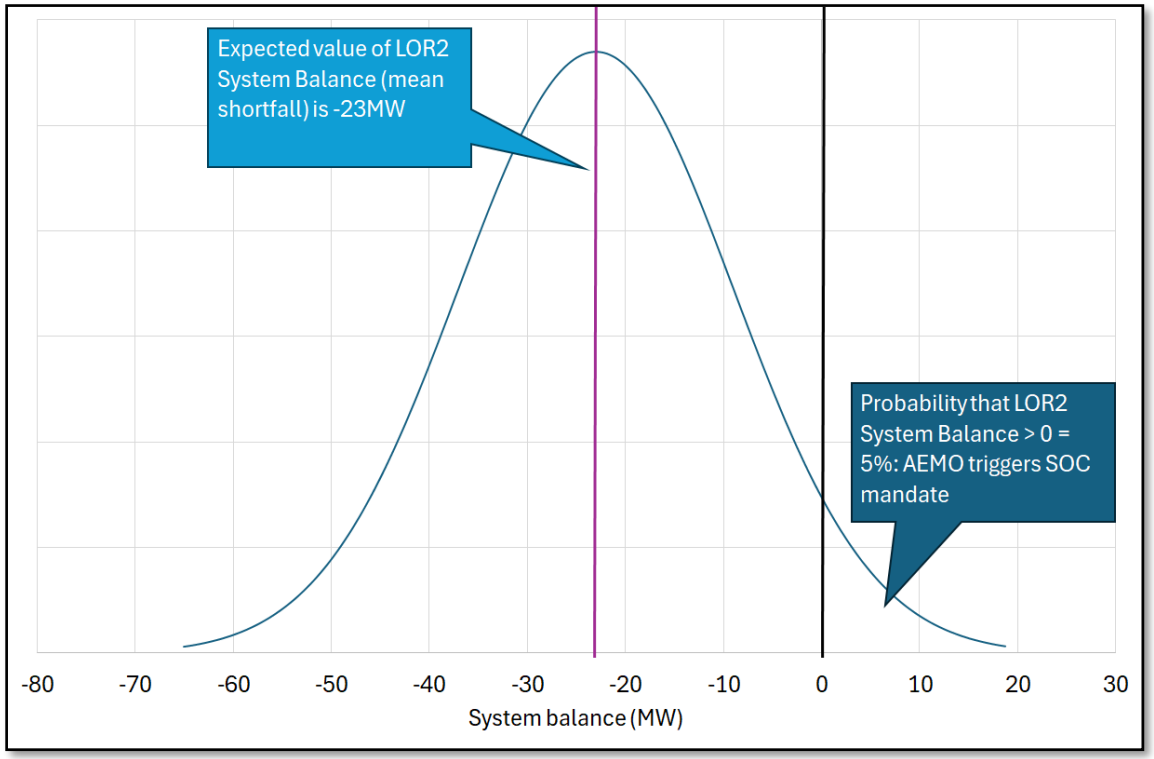
1. Does the Working Group have any comments on the proposed approach above?

Policy principles governing mandatory SOC Obligations

Notification period

- ESR operators require:
  - Sufficient notice so they have sufficient time to charge and to change their operating profiles; and
  - Assurance that any low reserve declaration is sufficiently accurate.
- The closer to real-time, the more accurate the shortfall forecast, but the less time the ESR operator has to prepare.
  - Longer-duration ESRs take longer to charge and require more notice.
- Scarcity and intervention rules allow AEMO to intervene (direct) to resolve actual or projected energy shortfalls forecast one week from real-time (ESMR 7.7.4(b)).
  - System conditions can change significantly over a week.
- Need to balance the need for accurate forecasts with notification lead-time:
  - One possibility is to incorporate uncertainty measure into Forecast Unscheduled Operational Demand; and
  - Probabilistic assessment already part of LOR framework: ESMR and recently commenced LRC WEM Procedure requires AEMO to conduct probabilistic assessment.

Hypothetical distribution of X-hour-ahead System Balance* forecast for a Trading Interval



***e.g., System Balance for LOR2 declaration equals Available Capacity – Demand – 70%x largest contingency**

Policy principles governing mandatory SOC Obligations

Notification periods contd..

- Propose that AEMO must make best endeavours to declare LOR-SOC condition and SOC mandate requirements by 8pm on the Scheduling Day.
- Despite best endeavours, AEMO may not be able to make the 8pm Scheduling Day cut-off. In such a case, AEMO must make the declaration no later than 8am on the Trading Day.

Questions

1. Does the Working Group have any comments on the proposed approach above?

Policy principles governing mandatory SOC Obligations

Setting the SOC obligations

- AEMO already conducts assessment of fleet SOC needed to maintain PSSR:
  - Propose adopting existing framework to set a % SOC to apply to the entire fleet at that start of each ESR's ESROD.
  - Uniform % SOC to apply to all ESRs in the first applicable ESROI.
- Approach is simple to implement

Policy principles governing mandatory SOC Obligations

Other considerations - ESRs all charging at the same time can create system problems

- LOR declaration and SOC mandate at the beginning of a Trading Day could result in multiple ESRs charging at the same time causing system stress.
- Newer ESRs will start discharging earlier than incumbents:
  - Incumbents charging during the first two ESROIs of new ESRs could result in ESR charging each other.
  - Need ability to coordinate charging to avoid charge cannibalisation.
- AEMO has power to direct charging to maintain PSSR under ESMR 3.4.4, 3.5.4 and 3.5.5. Rather than relying on these provisions, propose introducing new clause to empower AEMO to direct charging to maintain PSSR when SOC mandate is invoked.

Questions:

1. Does the Working Group agree that AEMO should be empowered to direct charging to maintain PSSR when a SOC mandate is invoked, if required?
2. Should ESR be prohibited to charge during the longest ESROD duration, unless instructed to do so by AEMO?

Policy principles governing mandatory SOC Obligations

Other considerations

Withdrawal of SOC mandate

- Power system conditions may change meaning LOR event may not eventuate.
    - If AEMO determines that an LOR will no longer eventuate, it should be able to withdraw the SOC mandate.

Principles underpinning approach to declaring SOC mandate

- Approach and methodology should be as simple as practicably possible, while providing adequate certainty to participants, to ensure transparency and cost-effective implementation and to avoid unintended consequences.
- Approach and methodology should minimise the risk of disruption to/intervention in normal market processes.

Questions

1. Does the Working Group agree that AEMO must withdraw SOC mandate if system conditions indicate LOR will no longer eventuate?
2. Does the Working Group have any comments on the general principles underpinning the methodology?

Additional Charge Shortfall Refund to apply during SOC mandate intervals

Existing refund regime on its own may not ensure compliance with SOC obligations

- Technical Analysis indicated that revenue from high prices during the day can exceed refunds for non-delivery during ESROIs.
- Exploring compliance by design – the presence of Civil Penalty provisions on its own may not be enough of a deterrent to noncompliance with new obligations.
- 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 is proposed.
    - WG expressed concern about potential implementation costs.
- Implementation could be simplified if additional refund mechanism was incorporated into existing refund regime as follows:
    - Increase the Maximum Facility Refund for ESRs to more than 100% of annual Capacity Payments (e.g. RCM review set Facility Maximum Peak Refund Factor to 125%);
    - Increase the DRF cap to a higher value to apply only to ESRs and only when AEMO has declared a SOC mandate.
- AEMO to assess costs and practicality of above.

Questions

1. Subject to cost assessment, Does the WG agree to variation of existing refund regime to increase DRFs for ESRs when SOC mandate applies and to increase the annual cap?
2. Should annual payments be capped at 125% like DSPs?

Issues identified but determined to be out of scope

Mix of Capability Classes needed to meet Planning Criterion

Capability Class mix needed to ensure reliability

Potential of using Technical Analysis to inform optimum Capability Class mix discussed at start of review

- Modelling to inform future supply mix needed to meet Planning Criterion is complex, time-intensive and outside the scope of this review:
  - Requires modelling different capacity mix scenarios further out than 2030 to understand how different capacity scenarios would affect the quantum location and timing of unserved energy.
- Type of modelling required is outside the scope of the ESOO:
  - One option is to change the ESM Rules to include such modelling in the scope of the ESOO?
  - Alternatively, this type of modelling would be conducted as part of Whole of System Plan (WOSP) modelling.

Annex 1

Detailed evaluation of ESR derating options

SEO Evaluation Criteria

Capacity certification/derating approach

Outcome sought	Map to SEO
1. Provides value for money by reasonably approximating contribution of batteries to reliability	Over-estimating contribution can lead to under-procurement, adversely affecting the security & reliability limb. Under-estimating contribution can lead to over-procurement, adversely affecting the pricing limb.
2. Method is transparent and predictable	Complex opaque methods may deter investment in new batteries which could adversely affect the security & reliability, pricing and environment limbs of the SEO.
3. Method does not result in volatile allocation from year to year	Uncertainty and volatility of capacity revenue streams may deter investment in new batteries which could adversely affect the security & reliability, pricing and environment limbs of the SEO.
4. Approach does not distort RCM and RTM investment signals	The RCM and RTM provides scarcity pricing signals to investors. Policies involving frequent intervention or off-market procurement to provide the same service (e.g. getting energy/capacity through SRC/NCESS) will erode investment signals in the WEM and could result in higher than otherwise long-term costs for the consumer therefore affecting the pricing limb of the SEO.
5. 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.

Storage derating option evaluation

Status quo

- CRC assigned equals maximum sustainable MW capacity, which could be delivered continuously across the Peak ESROD accounting for any charging limitations.
- ESR can retain their ESROD for ten years.
- Misalignment between capacity requirement and allocation added into Limb A of the Planning Criterion.
- New ESRs receive ESROD based on ADG calculations which looks at whether non-ESR capacity can meet demand in intervals adjacent to the previous cycle's ESROD.

Criteria	Draft evaluation
Provides value for money by reasonably approximating contribution of batteries to reliability	Reasonable job approximating contribution to peak period reliability, but does not represent contribution to overall reliability. The contribution will be over-estimated if depth of discharge is assumed to be 0 at time of certification. *Criteria met partially*
Method is transparent and predictable	LDM component is very simple and transparent. By contrast, the approach used to determine the ESROD is somewhat complex (but less complex compared to implementing an ELCC approach). *Criteria met substantially*
Method does not result in uncertainty or volatile allocation from year to year	No uncertainty in the LDM component as the participant will know their degradation profile ahead of time. Element of uncertainty for investors where the ESROD – grandfathering arrangements address this concern. *Criteria met substantially*
Cost and complexity of implementation is reasonable	Already implemented. *Criteria met fully*
Overall Performance	 ***Most criteria met substantially***

Storage derating option evaluation

Option 1: Incorporate ESR into amended RLM (Last-in Fleet ELCC)

- Fleet ELCC calculated for CC3 and ESR.
- New storage performance estimated based on peak or unserved energy minimisation heuristic.
- 10% POE peak and expected demand scenario:
  - Historical load shape from past 4/5 years;
  - Corrected for DPV.
- Fleet ELCC calculated as lower of whole period fleet ELCC and average of individual year fleet ELCC.
- Fleet ELCC allocated in proportion to performance in 12 Peak SWIS Intervals.
  - New ESR output determined using perfect foresight heuristic to minimise UE or peak.

Criteria	Draft evaluation
Provides value for money by reasonably approximating contribution of batteries to reliability	• Reliability contribution of ESR fleet estimated more accurately than LDM • Individual ESR RL will not reflect marginal impact of the resource, however, Fleet ELCC is a good approximation to marginal contribution of fleet. • Discourages charging and encourages high output during high demand periods *Criteria met substantially*
Method is transparent and predictable	• ELCC algorithms are complex; unlikely that participants can predict their ELCCs unless they create the required modelling infrastructure. • Issue could be mitigated somewhat in the ESOO through sensitivity analyses providing insights on what drives ELCC outcomes *Criteria not met*
Method does not result in uncertainty or volatile allocation from year to year	• Some risk of volatile allocations – mitigated through use of fleet ELCCs and use of multiple historical reference years. • ESR is not inherently volatile like CC3 resources, so will result in less volatile allocations than for intermittent resources. *Criteria met partially*
Cost and complexity of implementation is reasonable	Option being implemented for CC3T – this option would require further incorporating ESR into the new RLM calculations. *Criteria met partially*
Overall Performance	◐ ***Some criteria met substantially or most met partially***

Storage derating option evaluation

Option 2: Implement Individual (Last-in) ELCC)

- Individual ELCC calculated for CC3 and ESR.
- 10% POE peak and expected demand scenario:
  - Historical load shape from past 4/5 years;
  - Corrected for DPV.
- Individual ELCC calculated as lower of whole period individual ELCC and average of individual year ELCC.

Criteria	Draft evaluation
Provides value for money by reasonably approximating contribution of batteries to reliability	• Reliability contribution of ESR fleet estimated more accurately than status quo but less so than Option 1. Individual last-in ELCC results in under-estimation of correlated resources so that the sum of the individual ELCCs does not accurately represent the fleet ELCC. • Discourages charging and encourages high output during high demand periods *Criteria met partially*
Method is transparent and predictable	See Option 1 *Criteria not met*
Method does not result in uncertainty or volatile allocation from year to year	Moderate to high risk of volatile allocations – as evidenced with PJM experience. *Criteria not met*
Cost and complexity of implementation is reasonable	Would need to replace previously consulted on RLM. Method is more computationally intensive and complex *Criteria not met*
Overall Performance	○ ***Most criteria not met***

Storage derating option evaluation

Option 4: Incorporate ESR into amended RLM with least worst regrets

- Fleet ELCC calculated for CC3 and ESR.
- Multiple POE peak and expected demand assumptions combined with multiple historical load shapes used to create multiple scenarios.
- Fleet ELCC calculated for each demand scenario.
- Regret cost calculated for each demand scenario (if another scenario manifests).
- Choose ELCC of demand scenario with lowest regret cost.
- Fleet ELCC allocated in proportion to performance in 12 Peak SWIS Intervals.

Criteria	Draft evaluation
Provides value for money by reasonably approximating contribution of batteries to reliability	• Similar to Option 1, except ELCC calculated for many different demand scenarios, and fleet ELCCs selected from a single scenario to minimise regret cost. • Performs better than Option 1 as it considers a wider range of demand scenarios and models impact of other scenarios manifesting *Criteria met fully*
Method is transparent and predictable	Significantly more complex than Option 1 due to multiple demand scenarios and least-worst regrets analysis *Criteria not met*
Method does not result in uncertainty or volatile allocation from year to year	See Option 1 *Criteria met partially*
Cost and complexity of implementation is reasonable	Would need to replace previously consulted on RLM. Method is more computationally intensive and complex Misaligned with Planning Criterion and RCR definitions that are tied to 10% POE peak demand. *Criteria not met*
Overall Performance	***Some criteria met partially***

Annex 2

Additional ESR issues

Storage derating option evaluation

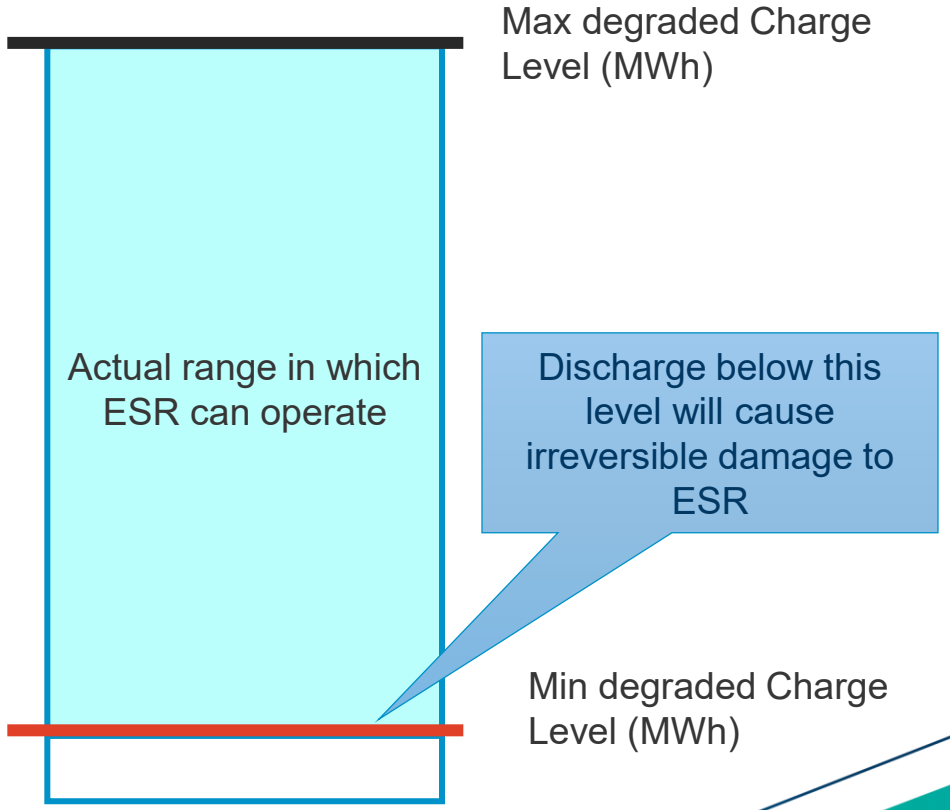
Status quo

CRC assigned equals Linearly Derated Capacity:

- The maximum capacity, in MW, of an ESR that can be guaranteed to be available over the Peak ESROD, being the minimum of:
  a) the nameplate capacity; and
  b) the maximum Charge Level capability (in MWh) divided by half the number of Trading Intervals in the Peak Electric Storage Resource Obligation Duration, being the maximum sustainable MW capacity, which could be delivered continuously across the Peak Electric Storage Resource Obligation Duration accounting for any charging limitations.

Issue 1: Participants are not submitting correct min Charge Level data

- Intention of ESMR is that the maximum discharge capability of the ESR is given by the blue area of the diagram:
  - In practice, participants indicating minimum charge level capability of 0% during certification.
  - This results in capacity over-allocation as depth of discharge is typically ~3%-5% of the theoretical maximum.
- Participant must indicate at time of certification their actual minimum Charge Level capability when operational.



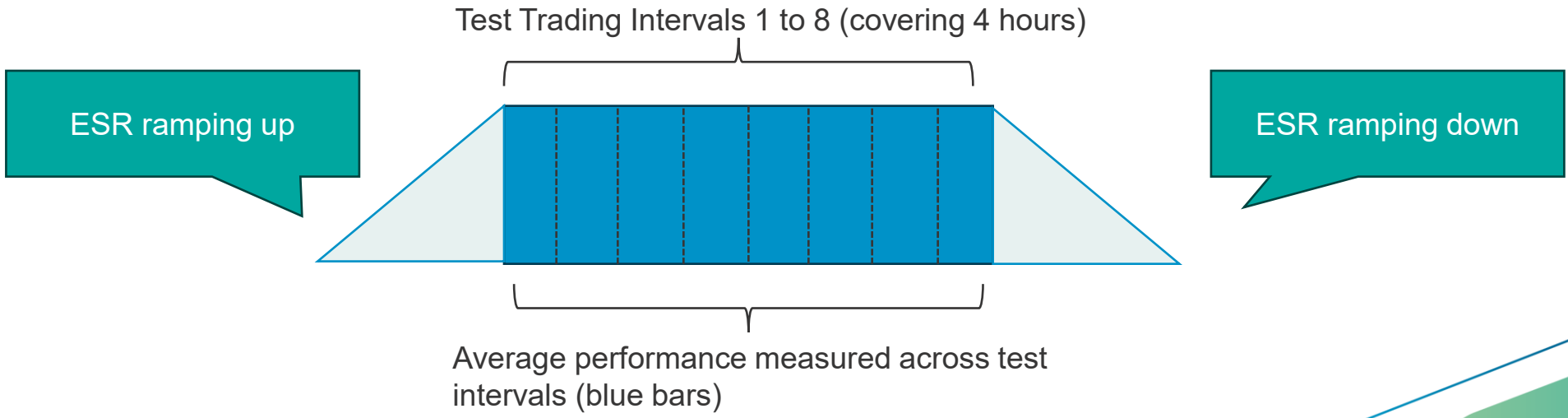
Storage derating option evaluation

Status quo continued

Issue 2: Reserve Capacity Testing rules do not account for ESR ramping

- Mismatch between how test performance is measured (ESMR 4.25.2E) and operational realities of ESR.
- ESR uses energy when ramping to its Required Level and then when ramping down to its minimum discharge depth.
- The average performance during the testing intervals will therefore not deliver the ESR's Required Level.
- However, area under trapezium does accurately reflect the ESR's performance capability.

Propose amending ESMR 4.25.2E to assess test performance using the area under the trapezium.



Annex 3a

Technical Analysis - Current State Analysis

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

Current-State Technical Analysis

Stage 1 and Stage 2

Stage 1: Identify Historical System Stress Events (SSEs)

- Identified SSEs using Market Advisories and Manual Constraints between November 2023 to August 2025.
- 26 SSEs were identified over this period.
- Analysed the characteristics of these SSEs such as seasonality, start and end times, type of day (business/non-business), duration, and common causes.

Stage 2: Detailed Analysis of the 48 hours leading up to and including each SSE

- For each of the 26 SSEs, analysed data for ESR Charge Levels, Energy-Sent Out, FCESS quantities, WEM Energy Prices.
- Analysed ESR Charge Levels both at event start and at ESR Obligation Interval (ESROI) start for each event.
- Additional detailed analysis for the 5 SSEs in which individual ESRs recorded charge levels below 50% at either event start or at ESROI start.
- Investigated possible drivers of low ESR charge levels during these 5 SSEs.
- Compared revenue for discharging ESRs prior to SSE start with refunds paid during the ESROI period on the SSE day.

What is a System Stress Event (SSE)?

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

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Note:
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- Investigated possible drivers of low ESR charge levels during these 5 SSEs.
- Compared revenue for discharging ESRs prior to SSE start with refunds paid during the ESROI period on the SSE day.

Annex 3b

Technical Analysis - Future State Analysis

Future-State Technical Analysis - Methodology

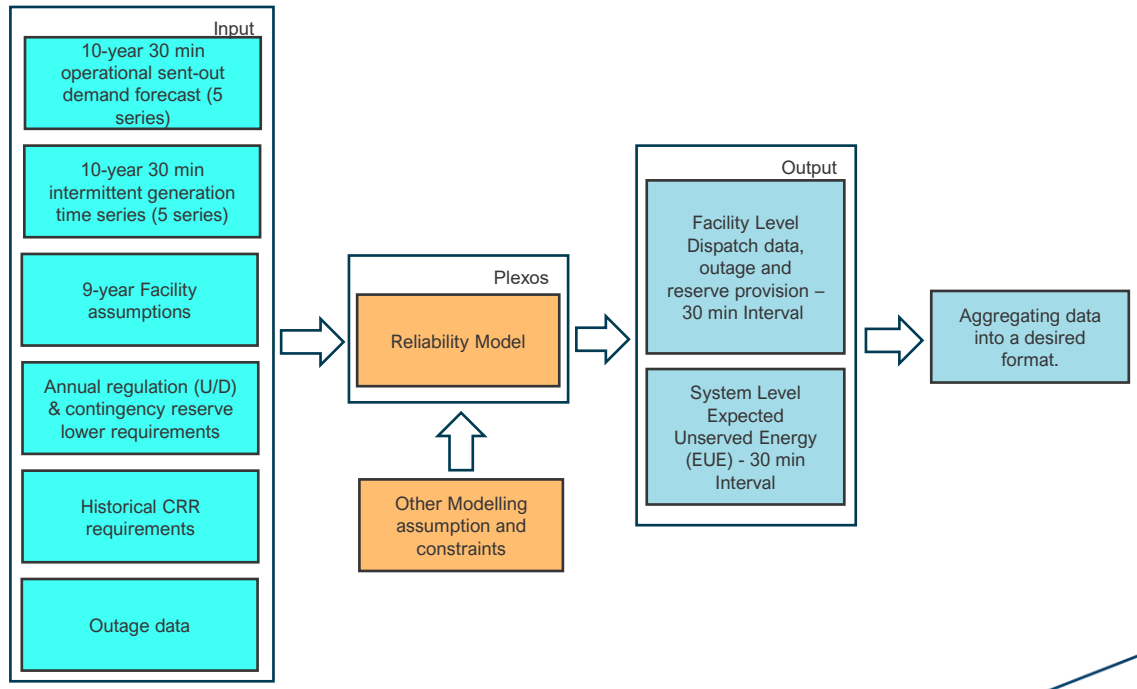
Modelling methodology (Source: AEMO)

AEMO have conducted modelling to forecast the conditions under which ESR dispatch will be required over the next 9 years.

The AEMO model:

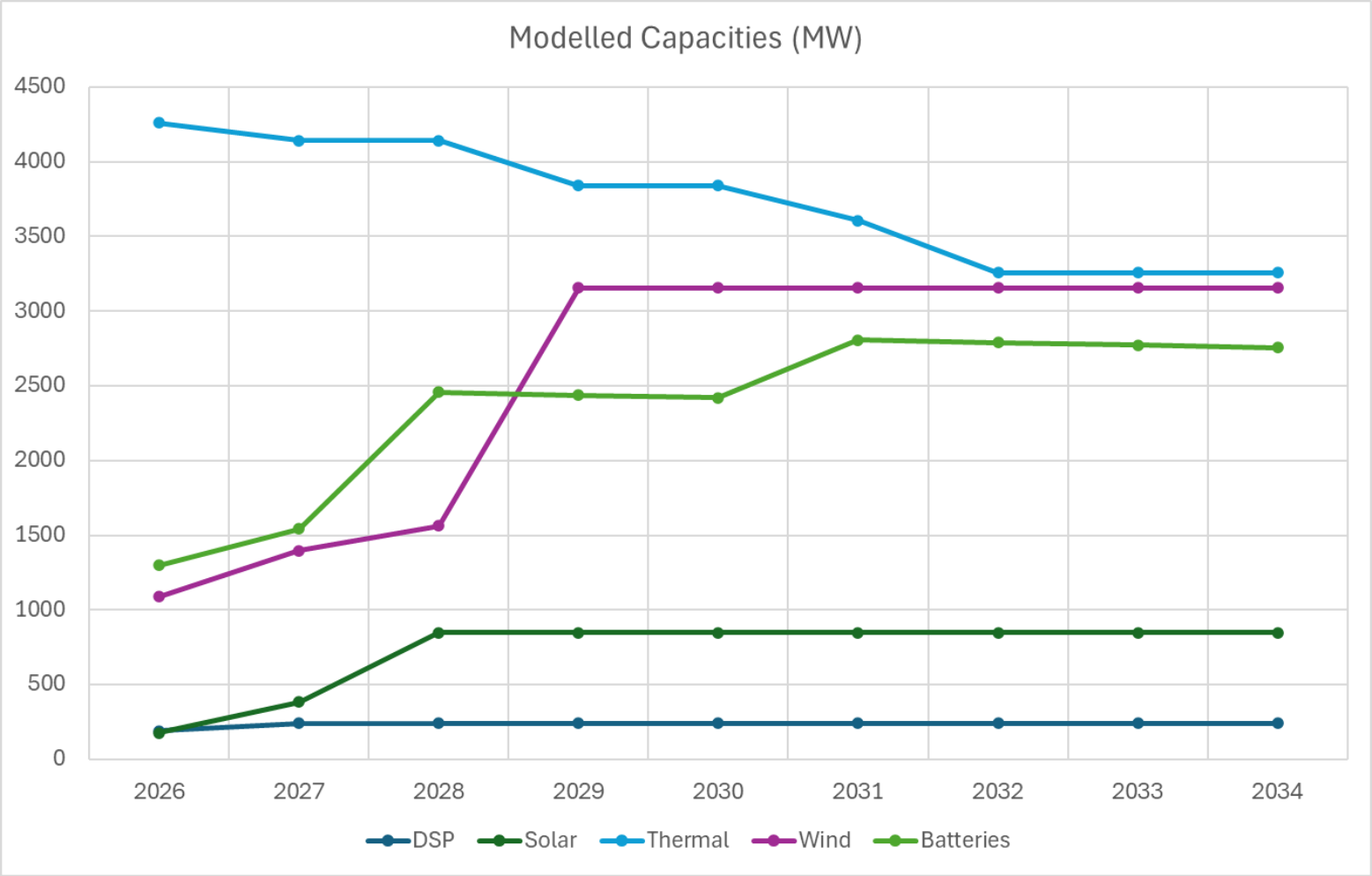
- Considers 5 reference years for ½ hourly demand shape and intermittent availability;
- Models 20 outage scenarios to consider impacts to unserved energy;
- Allows ESR to be dispatched up to its Capacity Credits with perfect foresight to optimally avoid unserved energy (i.e. ignores ESROI);
- Pushes ESR to the top of the merit order (ahead of DSP) to ensure ESR operates only during events which would otherwise cause unserved energy.

Modelled behaviour of ESR will be interrogated to understand conditions in which ESR discharge is required.



Future-State Technical Analysis - Assumptions

Capacity Assumptions (Source: AEMO)



Future-State Technical Analysis - implications

Conclusions from future-state analysis

- The times of day that the system requires ESR support vary by time of year.
- These patterns will vary significantly over the coming years as the system transitions to more variable intermittent generation.
- ESROI periods will have to adapt accordingly.
- Potentially, state of charge requirements could be made conditional on low wind forecasts, if forecasts are sufficiently reliable.

Annex 4

Detailed evaluation of DSP options

Options assessed against the SEO

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 batteries	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 batteries) 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

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* ***Changed to 8am – 12pm***	10am – 2pm ***Changed to 12–2pm***	2pm – 10pm

- 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 batteries 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***