Department of
Energy and Economic
Diversification
GOVERNMENT OF
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Energy
Policy WA

Capabilities Class 2 technologies Review

Consultation Paper

Contents

Abbreviations

Term	Definition
AEMO	Australian Energy Market Operator
ADG	Availability Duration Gap
BD	Business Day
BRCP	Benchmark Reserve Capacity Price
BTM	Behind-the-meter
CC1	Capability Class 1
CC2	Capability Class 2
CC2T	Capability Class 2 technologies
CC3	Capability Class 3
CRC	Certified Reserve Capacity
DSP	Demand Side Programme
DPV	Distributed photovoltaics
EFC	Effective Firm Capacity
ELCC	Effective Load Carrying Capability
ERA	Economic Regulation Authority
ESM	Electricity System and Market
ESR	Electric Storage Resource
ESRDR	Electric Storage Resource Duration Requirement
ESROD	Electric Storage Resource Obligation Duration
ESROI	Electric Storage Resource Obligation Interval
ESS	Essential System Service

Term	Definition
EUE	Expected Unserved Energy
FCESS	Frequency Co-optimised Essential System Service
GW	Gigawatt
ISO-NE	ISO – New England
KW	Kilowatt
LDM	Linearly derating method
LOR	Lack of reserve
LOLE	Loss of Load Expectation
LRC	Low Reserve Condition
LT PASA	Long Term Projected Assessment of System Adequacy
MAC	Market Advisory Committee
MW	Megawatt
MWh	Megawatt - Hour
NAFF	Network Augmentation Funding Facility
NAQ	Network Access Quantity
NBD	Non-Business Day
NCESS	Non-Co-optimised Essential System Service
PJM	Pennsylvania - New Jersey – Maryland
POE	Probability of Exceedance
PSSR	Power System Security and Reliability
RCM	Reserve Capacity Mechanism
RCOQ	Reserve Capacity Obligation Quantity
RCP	Reserve Capacity Price

Term	Definition
RLM	Relevant Level Method
RoCoF	Rate of Change of Frequency
RTM	Real-Time Market
SC	Supplementary Capacity
SEO	State Electricity Objective
SOC	State of charge
SSE	System stress event
ST-PASA	Short Term Projected Assessment of System Adequacy
SWIS	South West Interconnected System
TNI	Transmission Node Identifier
WEM	Wholesale Electricity Market

Executive summary

Capability Class 2 technologies Review

The Coordinator of Energy (Coordinator) is required to review the Electricity System and Market (ESM) Rules related to Capability Class 2 technologies (i.e. Electric Storage Resources (ESRs) and Demand Side Programmes (DSPs)), in accordance with section 4.13B of the ESM Rules at least once every five years.

In its transition to a decarbonised future, the South-West Interconnected System (SWIS) has experienced significant growth in ESR penetration as existing thermal generation retires, and decarbonisation efforts ramp up. The quantity of Capacity Credits allocated to ESRs under the Reserve Capacity Mechanism (RCM) has also increased in recent years. In this transition, the SWIS is facing some challenges regarding the operation of ESRs and DSPs, including:

- an ESR Facility's ability to meet its Reserve Capacity Obligation Quantity (RCOQ), which applies at the time of system peak demand, is dependent on its state of charge (SOC).
- DSPs are dispatched when there is a heightened risk of unserved energy. As peak demand periods in the SWIS change, DSP availability obligation intervals should align with power system needs. Behind-the-meter (BTM) storage can also contribute to system reliability via DSP participation. However, BTM storage assets are unlikely to be able to meet long-duration availability obligations.

It is critical that the ESM Rules include:

- mechanisms to ensure that ESR Facilities have sufficient charge to meet their RCOQ when they are most needed by the system; and
- DSP availability obligation intervals that capture intervals where system stress can credibly occur, while accounting for the duration-limited nature of BTM storage.

The Capability Class 2 technologies (CC2T) Review was initiated to work closely with stakeholders, including the Market Advisory Committee (MAC), the CC2T Working Group (Working Group) and the Australian Energy Market Operator (AEMO), to review the ESM Rules related to Capability Class 2 Technologies.

This paper sets out the outcomes and proposed changes regarding CC2T, including:

- ESR derating methodology;
- The setting of ESR Obligation Intervals (ESROIs);
- ESR Reserve Capacity testing;
- ESR state of charge obligations and compliance; and
- DSP availability obligation intervals.

The proposed changes outlined in this paper are required to maintain Power System Security and Reliability (PSSR), and to reduce barriers for ESRs and DSPs within the RCM.

Call for submissions

Stakeholder feedback is invited on the Review proposed outcomes outlined in this Consultation Paper. Submissions can be emailed to: energymarkets@deed.wa.gov.au. Any submissions received will be made publicly available on www.energy.wa.gov.au, unless requested otherwise.

The consultation period closes at **5:00pm (AWST) on 1 September 2026**. Late submissions may not be considered.

Summary of proposed review outcomes and rationale

Table 1 summarises the proposed review outcomes, with the rationale for each proposal.

Table 1: Proposed Outcomes and Rationale

Proposed outcomes	Rationale
Proposal 1 Amend the ESM Rules (clause 4.22.2E(a)) to allow AEMO to measure the total energy delivered for assessing ESR performance in a Reserve Capacity Test.	The current rules create a mismatch between how test performance is measured under the ESM Rules and the operational realities of testing an ESR. This proposal aims to change the way AEMO determines the Reserve Capacity Test performance of an ESR, so that total output (including ramping) is measured, thereby preventing ESRs from being oversized solely to meet testing requirements. Further information can be found in Chapter 3.
Proposal 2a Amend the ESM Rules to change DSP availability obligation intervals to 8:00am to 12:00pm (noon) and 2:00pm to 10:00pm on all Business Days. Stakeholder feedback is sought on whether there is justification for a 4:00am to 8:00am morning interval instead of the 8:00am to 12:00pm (noon).	This proposal aims to align DSP availability with system requirements and encourage the participation of BTM storage in DSP aggregations, while seeking to minimise implementation costs. Concerns have also been raised regarding the period before 8:00am. Stakeholder feedback is therefore requested on whether the morning window should be changed to 4:00am to 8:00am, while still maintaining the requirement that availability occurs within a single Trading Day and retains the 12-hour obligation. Further information can be found in Chapter 4.

<table>
<tr><th>Proposed outcomes</th><th>Rationale</th></tr>
<tr><td>Proposal 2b
Amend the ESM Rules to:
• allow a DSP participant to choose only the 2:00pm to 10:00pm window option and receive the Reserve Capacity Price derated by 8/12 to reflect the reduction of the DSP availability.
• require that any DSP participant that chooses only the 2:00pm to 10:00pm option trades its Capacity Credits through AEMO.</td><td>Some large loads cannot restart quickly enough between the morning and evening availability obligation windows. To facilitate their participation as a DSP, this proposal allows participants to opt into the evening availability obligation window only, in exchange for a lower Reserve Capacity Price.
Given that DSPs that opt only for the evening obligation window provide reduced reliability and the price they receive for their capacity credits is lower, these capacity credits must be traded directly through AEMO.
Further information can be found in Chapter 4.</td></tr>
<tr><td>Proposal 2c
Amend the ESM Rules to:
• remove the option for DSPs to offer availability outside the availability obligation intervals.
• allow a DSP to associate different loads within its portfolio to the morning and the evening availability obligation intervals (for every Trading Day) no later than 3 weeks before the effective date.
• empower AEMO to conduct Reserve Capacity Tests in the availability windows selected by the DSP.</td><td>To make DSP participation easier:
• the application process will be simplified by removing the option for DSPs to offer availability outside of the standard availability obligation windows.
• DSP providers can change which Associated Loads they plan to use to provide greater portfolio flexibility, provided this is done with sufficient notice.
Further Reserve Capacity testing changes are needed to verify that DSPs can provide their RCOQ in the window or windows they have selected.
Further information can be found in Chapter 4.</td></tr>
</table>

Proposed outcomes	Rationale
Proposal 3 Amend the ESM Rules to allow a DSP participant to have the Capacity Credits associated with a single load reduced and a corresponding portion of the Reserve Capacity Security returned, provided that: • an Associated Load greater than 5 megawatt (MW) ceases operations permanently or for the entirety of a Capacity Year in which the relevant DSP has Reserve Capacity obligations; • the DSP participant notifies AEMO no later than 1 April in Year 3 of the Reserve Capacity Cycle; and • the relevant Market Participant provides sufficient evidence that the load has ceased operations.	This proposal aims to: • reduce the risk that a DSP provider will be less likely to participate in the RCM where factors outside of its control cause an Associated Load to cease operations, but its Reserve Capacity obligations persist; and • recognise that the Reserve Capacity Requirement will be reduced if a significant DSP Associated Load above a material MW threshold exits the system before the relevant Capacity Year. Further information can be found in Chapter 5.

Proposal 4a
 	
Amend the ESM Rules to:
 	
• update clause 3.17.11 (the head of power for the Low Reserve Condition (LRC) WEM Procedure) to empower AEMO to incorporate a lack of reserve – state of charge (LOR-SOC) condition into the LRC Framework, as follows:
  – the declaration of an LOR-SOC condition triggers the state of charge (SOC) obligation on the ESR fleet comprising ESRs with a Peak Reserve Capacity Obligation Quantity;
  – the LRC WEM Procedure will also be amended to outline:
	Analysis shows that system stress events requiring ESRs to have higher charge levels are infrequent but have the potential to impact PSSR. The infrequent nature of these events does not justify a redesign of the market. Targeted AEMO intervention when these events arise provides a more effective and simpler approach to implementation.
	
	This proposal aims to empower AEMO during these infrequent periods when appropriate ESR SOC levels are required to meet the upcoming evening peak obligation, and AEMO determines that ESR discharge is necessary to prevent the risk of unserved energy.
	
	The ESM Rules will define the information that must be included in the WEM Procedure. This proposal ensures full transparency for Market Participants regarding how and when the new LOR-SOC obligation will be applied.

Proposed outcomes	Rationale
○ the system conditions under which the LOR-SOC obligations will apply; and ○ the methodology AEMO will use to determine the SOC obligation level. • allow AEMO to withdraw a LOR-SOC condition and SOC obligations if it determines they are no longer necessary; • specify the notification timings for AEMO when declaring a LOR-SOC condition: – AEMO must use best endeavours to declare the LOR-SOC condition and SOC obligations by 8:00pm on the Scheduling Day; and – AEMO must declare the LOR-SOC condition and SOC obligations no later than 8:00am on the Trading Day. • specify that the LOR-SOC obligation will be for a uniform charge level applicable to all ESR Facilities with Reserve Capacity obligations, and that these Facilities must be at that level at the start of their relevant ESROIs; • specify the information that must be made available to relevant Market Participants to provide a reasonable level of certainty about the event occurring; and • specify that the SOC obligation applies to an ESR Facility's remaining available capacity to account for outages.	Further information can be found in Chapter 6.

Proposed outcomes	Rationale
Proposal 4b Stakeholder feedback is sought on the following two options aimed at assisting ESR operators in complying with an LOR-SOC obligation that applies while avoiding non-compliance with other obligations. **Option 1 (AEMO's preference):** Amend the ESM Rules to provide that, on a Trading Day when an LOR-SOC condition is in effect, AEMO must: • apply Constraint Equations to prevent ESRs from being dispatched for Injection before their relevant ESROIs, unless they are instructed by AEMO to provide FCESS or to maintain PSSR; and • apply Constraint Equations to prevent ESRs from being dispatched for withdrawal during their ESROIs and during the ESROIs of other ESRs, unless they are instructed by AEMO to provide FCESS or to maintain PSSR. **Option 2:** • allow ESR operators to make zero quantity offers for energy injections to preserve charge and zero withdrawal bids to ensure charging outside their ESROIs on a Trading Day when a LOR-SOC condition is in effect; and • introduce an obligation preventing ESRs from charging during their ESROIs and during the ESROIs of other ESRs on a Trading Day when a LOR-SOC condition is in effect, except where AEMO instructs them to provide FCESS or to maintain PSSR.	To facilitate compliance with the proposed LOR-SOC, it is proposed to amend the ESM Rules to provide Market Participants with an option that allows compliance with the LOR-SOC obligation without risking non-compliance with their offer requirements. Both options are expected to achieve the same outcome but differ in the level of effort required from different stakeholders: • Under Option 1, Market Participants will continue to comply with the relevant obligations when submitting offer quantities. This provides AEMO with greater visibility of the operational capability of ESR facilities. As a result, AEMO would need to perform less manual work if intervention for PSSR purposes is required. • Option 2 offers ESR operators a simpler and more straightforward method for operating under a LOR-SOC obligation. However, this simplicity shifts additional burden to AEMO, which may need to undertake more manual work if it needs to intervene. Further information can be found in Chapter 6.

Proposed outcomes	Rationale
Proposal 5 It is proposed to amend the ESM Rules to introduce an addition to the current refund mechanism for ESRs when an LOR-SOC mandate applies.	An addition to the current refund mechanism will be introduced to incentivise appropriate behaviour and ensure that other technology types are not adversely affected. The proposed change is designed to minimise implementation costs while providing a simple enhancement to the financial incentives for ESRs to comply with the LOR-SOC obligation. Further information can be found in Chapter 7.

1. Introduction

The Coordinator of Energy (Coordinator) is required to review the Electricity System and Market (ESM) Rules related to Capability Class 2 technologies (i.e. Electric Storage Resources and Demand Side Programmes), in accordance with section 4.13B of the ESM Rules at least once every five years.

The Coordinator has undertaken this review in consultation with the Market Advisory Committee (MAC), Capability Class 2 Technologies Review Working Group (Working Group) and the Australian Energy Market Operator (AEMO).

This paper sets out the proposed outcomes of the Capability Class 2 Technologies Review (the Review).

1.1. Regulatory context

The requirement for the Review was originally added to the ESM Rules in November 2021 and was subsequently amended in January 2025 to implement the outcomes of the Reserve Capacity Mechanism (RCM) Review, including amendments related to ESRs and DSPs.

The scope of the Review under section 4.13B of the ESM Rules, both before and after January 2025, is summarised below:

Table 2: Scope of the Review required under ESM Rule 4.13B (prior to 15 January 2025)

ESM Rule clause	Review requirement
4.13B.1	The Coordinator must review the effectiveness of the approach to certification of Reserve Capacity for ESR.
4.13.B.3(a)	The Coordinator must review the methodology for rating the capacity of ESRs for Certified Reserve Capacity (CRC).
4.13.B.3(b)	The Coordinator must review the approach to setting the ESR Obligation Duration (ESROD).
4.13.B.3(c)	The Coordinator must review the approach for setting the ESR Obligation Intervals (ESROIs).
4.13.B.3(d)	The Coordinator must review the ESROI methodology and processes used by AEMO.

Table 3: Scope of the Review required under ESM Rule 4.13B (after 15 January 2025)

ESM Rule clause	Review requirement
4.13B.1	The Coordinator must review the effectiveness of the approach to certifying ESRs and other energy limited resources, collectively Capability Class 2, in accordance with section 4.13B and against the State Electricity Objective (SEO).
4.13.B.1(a)	The Coordinator must review the methodology for rating the capacity of ERSs and DSPs for CRC.
4.13.B.1(b)	The Coordinator must review the Reserve Capacity Obligation Quantity (RCOQ) determination for ESRs and DSPs.
4.13.B.1(c)	The Coordinator must review the effectiveness of Reserve Capacity refunds for ESRs and DSPs.
4.13.B.1(d)	The Coordinator must review the operation of clause 4.5.12 to ensure adequacy with clause 4.5.9(b) (reliability limb).
4.13B.3(a)	The Coordinator must review the capacity rating methodology for CRC for all Capability Class 2 technologies.
4.13B.3(b)	The Coordinator must review the dynamic ESR Obligation Duration (ESROD) and the Availability Duration Gap (ADG) calculations.
4.13B.3(d)	The Coordinator must review the AEMO method for setting the Mid-Peak ESR Obligation Interval (ESROI).
4.13B.3(f)	The Coordinator must review the year to year ADG trends and impact on certification.
4.13B.3(g)	The Coordinator must review the methodology for Peak and Flexible DSP Dispatch Requirements.

The provisions introduced by the Amending Rules made on 15 January 2025 have not been in place for a sufficient amount of time and, therefore, the Coordinator considers that a review of these provisions would not appropriately capture their impact. The Coordinator considers that it is appropriate to undertake a review of the provisions that will have been in operation for five years at the completion of the review, in line with the intent of the relevant ESM Rules.

The subject of clause 4.13B.3(b) – the ADG calculations, was reviewed in 2025, with changes implemented through the Tranche 8 ESM Amending Rules. Consequently, this item will not be considered as part of this Review given the impact of these changes cannot yet be properly measured or evaluated during this Review.

Given the above, the Coordinator has set the following scope for the Review:

Table 4: Scope of Review

Issue in scope	Map to ESM Rule 4.13B
Issue 1: Review whether current ESR certification methodology (Linearly Derating Method) and other provisions related to ERS are still aligned with SEO. See Chapters 2.1, 2.2, and 3.	4.13.B.1(a), 4.13B.3(a) 4.13B.3(b) 4.13B.3(c) (ESRs only)
Issue 2: Review Reserve Capacity Refunds regime and evaluate the potential to sharpen availability incentives. See Chapter 7.	4.13B.1(c) (ESRs only)
Issue 3: Review the DSP availability obligations against the SEO and potential improvements to DSP participation. See Chapters 4 and 5.	4.13.B.1(a), 4.13.B.1(b)
Issue 4: Identify policy options to improve ESR availability (based on technical analysis). See Chapter 6.	4.13.B.1(a), 4.13.B.1(b), 4.13.B.3(d)
Issue 5: Assess whether the existing Capability Classes approach (under clause 4.5.12) enables compliance with the reliability limb of the Planning Criterion. See Chapter 2.3.	4.13B.1(d)

1.2. Subsequent review

The review required by section 4.13B, which includes assessing CC2T, must be conducted at least once every five years. Given the dynamic nature of the energy transition, this Review focuses on the next five years rather than a longer timeframe, over which forecasts are likely to be less accurate.

As the system evolves and conditions change, the next review in 2031 will address any new issues and challenges that arise in the interim and cannot currently be foreseen.

The next review will also re-examine the matters covered in this review and evaluate whether the proposals, if implemented, are operating as intended.

1.3. Background

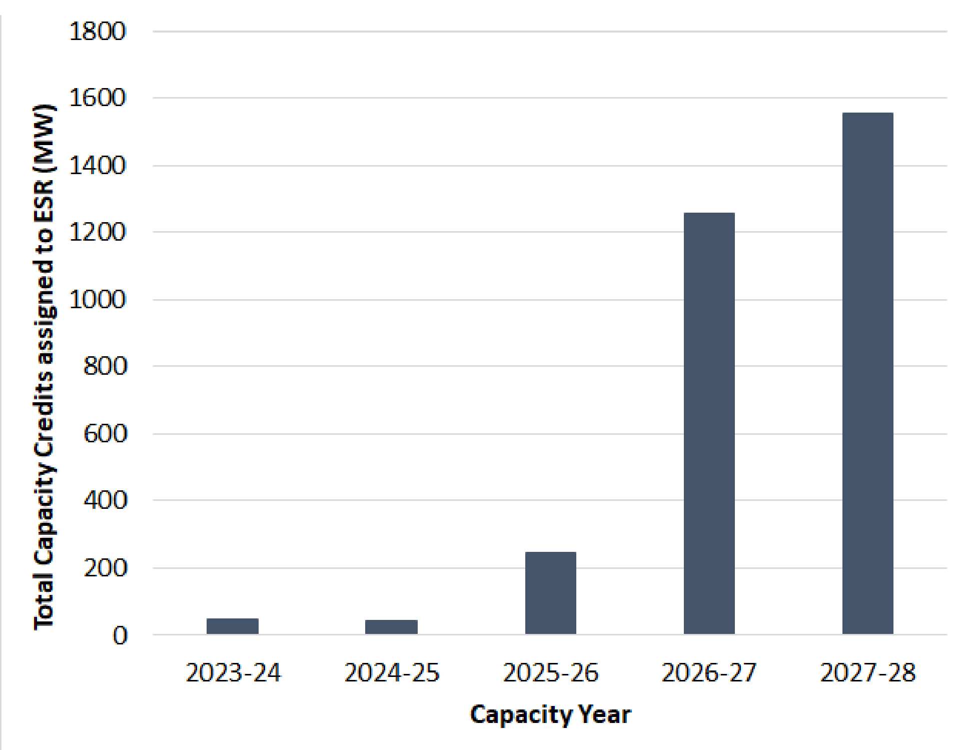
The increase of ESR capacity in the WEM presents opportunities and challenges

The SWIS has experienced significant growth in ESR penetration as existing thermal generation retires and other decarbonisation efforts ramp up.

The quantity of ESRs receiving Capacity Credits in the RCM has increased significantly in recent years, from 46.25 megawatts (MWs) of capacity assigned in the 2023-24 Reserve Capacity Cycle to 1,557 MW of Peak Capacity Credits assigned in the 2025-26 Reserve Capacity Cycle (see Figure 1). This increase has been driven, at least in part, by:

- High Reserve Capacity Prices, associated with changes to Benchmark Technology that is used to set the Benchmark Reserve Capacity Price (BRCP). The BRCP for the 2028-29 Reserve Capacity Cycle was determined by the Economic Regulation Authority (ERA) to be $488,500/MW/Year.[1]
- Grandfathering arrangements have been implemented to provide investor certainty by allowing ESRs to retain their original ESR Duration Requirement (ESRDR) for up to ten years, so that increases in the ADG do not reduce the Capacity Credits assigned to incumbent ESRs.

Figure 1: Peak Capacity Credits assigned to ESR Facilities since 2023-24



Source: AEMO (excludes Capacity Credits assigned to ESRs certifying as Non-Scheduled Facilities)

[1] See 2026 Benchmark Reserve Capacity Prices for the 2028-29 capacity year: Final Determination.

ESR duration obligations must be aligned with power system needs

The increase in ESR penetration presents both opportunities and challenges. As intermittent weather-dependent resources continue to grow and existing thermal generation retires, CC2T (particularly ESR) will become increasingly critical to maintaining system reliability. It is therefore important for the durational obligations placed on ESR to be aligned with system needs.

The ESM Rules must place effective and sufficient incentives on ESRs to be available

The ability of ESRs to respond to the reliability needs of the system is heavily dependent on how they charge:

- The Wholesale Electricity Market (WEM) does not have multi-period optimisation or unit commitment; this means that AEMO is not empowered to commit ESRs or schedule their charging.[2]
- As WEM participants self-schedule and are duration limited, they are responsible for ensuring that they have sufficient charge to meet their RCM and Real Time Market (RTM) obligations.

Unlike thermal Scheduled Facilities, for which AEMO has assurance that sufficient fuel is available by virtue of the certification process, AEMO does not have the same level of assurance that an ESR Facility will maintain sufficient SOC to comply with its RCOQ.

Thermal Scheduled Facilities have their fuel arrangements rigorously tested to ensure they have daily access to 14 hours of fuel to generate during the Capability Class 1 Assessment Intervals (8am to 10pm on Business Days). Accordingly, AEMO can reasonably assume that, unless a thermal generator suffers an unexpected contingency, it will have sufficient fuel to generate during these intervals. By contrast, an ESR Facility's ability to ensure daily access to energy, and therefore an appropriate SOC, cannot be assured.

For these reasons, it is critical that the ESM Rules include mechanisms to incentivise ESR Facilities to charge in a manner that enables them to meet their Reserve Capacity obligations when required.

DSP availability rules should be aligned to system need and enable new technologies to participate

DSP availability obligations must be aligned with power system needs

DSPs are assigned Capability Class 2 and are subject to more requirements on their availability than ESR. DSPs are treated as a last resort and are only dispatched when there is a heightened risk of unserved energy.

[2] clause 7.5.10 enables a Market Participant to request AEMO to include Constraint Equations for their ESR Facility to ensure their energy and FCESS dispatch targets are achievable given their charge levels. While all registered ESR Facilities currently have storage constraints, these constraints rarely bind in practice.

As power system operations become more volatile, DSPs may be required more frequently to reduce Unscheduled Operational Demand. It is therefore important to ensure that DSP obligations capture intervals during which system stress can credibly occur.

Recently, supplementary capacity services have been procured by AEMO to mitigate the risk of unserved energy occurring outside DSP availability obligation intervals. For example:

- In the 2025 ESOO, AEMO forecast that unserved energy may occur between 8:00pm and 10:00pm during the Hot Season, when DSPs are unavailable and ESRs are largely depleted. Consequently, AEMO identified a requirement to procure an additional 50 MW of capacity through Supplementary Capacity (SC).

Contracted services have been used to supplement DSP due to the limited number of DSP participants. For example:

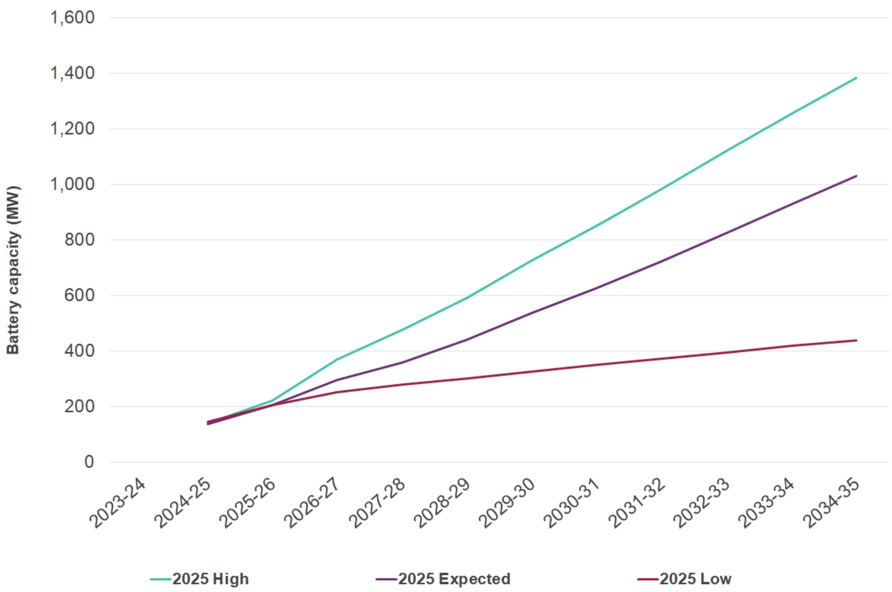
- In response to heat conditions on 20 January 2025, AEMO activated a total of 20MW of DSP response, along with 85 MW procured through the SC and Non-Co-optimised Essential System Service (NCESS) mechanisms.

As existing thermal generation retires from the system, maintaining reliability during extreme weather conditions will require increasing reliance on ESRs and DSPs. It is therefore critical that DSP availability obligation intervals are aligned with system needs to minimise reliance on more costly ad hoc procurement

DSP availability obligations should enable the participation of Behind-the-Meter (BTM) storage

The residential battery schemes have resulted in a large uptake of BTM storage with AEMO forecasting an increasing trend in uptake – see Figure 2.

Figure 2: Forecast residential battery capacity (MW)



Source: 2025 WEM ESOO

BTM storage can contribute to system reliability via DSPs. While residential storage capacity is forecasted to increase significantly, commercial and industrial BTM storage can also contribute to system reliability. Further, residential, commercial, and industrial BTM storage can operate together within an aggregated DSP portfolio. However, as BTM storage is duration limited, it is unlikely to meet a continuous 12-hour availability obligation.

This Review assessed alternative availability obligations to enable BTM storage to participate in the RCM as part of a DSP.

1.4. Approach to the Review

Consultation

The Coordinator has undertaken the Review in consultation with the MAC, the Working Group and AEMO.

The MAC established the Working Group to support the Review.

Further information on the Review is available from the Department of Energy and Economic Diversification website, including the Scope of Work, the Terms of References for the Working Group, and papers and minutes of the Working Group.[3,4]

Review methodology

The review methodology comprised qualitative and quantitative technical analysis.

Qualitative analysis

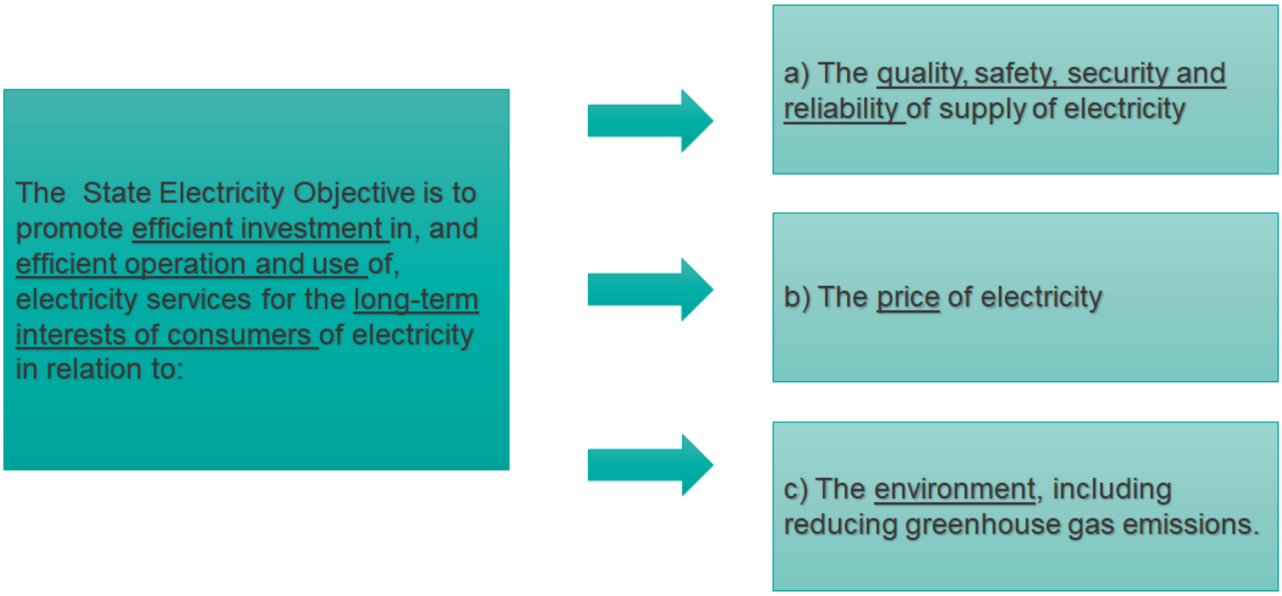
Policy options developed during the review were assessed against the SEO using multi-criteria analysis.

Evaluation criteria that mapped to the three limbs of the SEO were developed to assess different policy options. The three limbs of the SEO are shown in Figure 3.

[3] Capability Class 2 Technologies Review

[4] Capability Class 2 Technologies Review Working Group

Figure 3: The three limbs of the SEO



The evaluation criteria that were developed for assessing different policy options is detailed in Appendix C.1 and E.1.

Policy options were evaluated to see how well they met the criteria as shown in the Figure 4.

Figure 4: Rating scale for policy options evaluation

○	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

Technical analysis

The Review also conducted technical analysis to understand:

- The nature of historical power system incidents in which the availability of CC2T was critical to maintaining PSSR, examined through a current state analysis.
- The circumstances under which ESRs and DSPs are likely to be needed in the future to avoid unserved energy, examined through a future state analysis.

Current state analysis

Historical system stress events (SSEs) between October 2023 and August 2025 were examined to understand the characteristics and drivers of SWIS stress events.

Policy recommendations were informed by SSEs occurring after November 2024, as this is after the implementation of ESM Amending Rules arising from the Frequency Co-optimised Essential System Service (FCESS) Cost Review, which addressed previous market effectiveness issues.

SSEs were defined by identifying:[5]

- Market Advisories with LRC and/or energy and ancillary services shortfall; and.
- manual (non-network) constraints applied by AEMO.

This resulted in 26 SSEs being selected for investigation, including analysis of:

- the underlying causes, timing and duration of the SSEs;
- ESR charging behaviour during the SSEs; and
- the relationship (if any) between FCESS enablement and charge levels.

[5] See Appendix D.1.1 for a more detailed definition of SSEs.

In addition to reviewing historical SSEs, DSP activation events between October 2023 and February 2025 were examined to analyse the timing and duration of DSP dispatch events.

The detailed methodology is included in Appendix D.1. The results of the current state analysis are presented in the body of this report (see Chapters 2.2, 4.2, and 6) and in Appendix D.1.

Future state analysis

AEMO conducted modelling to forecast when ESR dispatch is required to avoid unserved energy for Capacity Year 2026-27 through to 2030-31 (inclusive).

AEMO's model is a probabilistic Monte Carlo simulation model that uses nine reference (historical) load years to represent variation in weather conditions and five forced outage scenarios to represent random outages. This results in 180 iterations per Trading Intervals, capturing system conditions, available capacity, and demand under different weather and outage conditions.

The model further assumes that ESRs are at the top of the merit order (but behind DSPs), such that it is only dispatched to avoid unserved energy. Consequently. ESROIs are not considered, and ESR dispatch is determined by the need to avoid unserved energy.

The detailed methodology is included in Appendix D.2. The results of the future state analysis are presented in the body of this report (see Chapters 2.2 and 6) and in Appendix D.2.

1.5. Structure of this paper

This document is structured as follows:

- Chapter 2 summarises outcomes for review items that have not resulted in amendment. This includes the approach for:
    - derating ESR methodology;
    - the setting of ESR Obligation Intervals (ESROIs); and
    - prioritising technology within Capability Class 2 in the Network Access Quantity (NAQ) Model.
- Chapters 3 to 5 set out the review outcomes where amendments to the ESM Rules are proposed. These include:
    - amendments to the ESR Reserve Capacity Test rules to allow test performance to include energy produced when ramping up or down during a test;
    - amendments to DSP availability obligations intervals;
    - amendments to allow the return of a DSP security deposit;
    - the introduction of an SOC mandate that empowers AEMO to set a Peak Certified ESR fleet charge level during LRC. This establishes the minimum SOC for an ESR facility before it enters its applicable ESROIs; and

    - amendments to the Reserve Capacity refund regime to introduce higher refunds (applicable only to ESR) during the ESROIs in which a SOC mandate applies.
- The appendices contain additional detail, including:
    - a jurisdictional review of ESR derating approaches;
    - a jurisdictional review of Demand Side approaches;
    - details of policy options evaluation against the SEO; and
    - technical analysis methodology and results.

1.6. Stakeholder consultation

Stakeholder feedback is invited on the Review outcomes and proposed changes as outlined in this Consultation Paper.

Submissions can be emailed to: energymarkets@deed.wa.gov.au.

Any submissions received will be made publicly available on www.energy.wa.gov.au, unless requested otherwise.

The consultation period closes at 5:00pm (AWST) on **1 September 2026**. Late submissions may not be considered.

2. Items assessed – No amendments proposed

2.1. Electric Storage Resources derating approach

ESRs are duration limited technologies, which means that their capacity contribution must be assessed to reflect their contribution to system reliability.

In the WEM, ESRs are assessed and, where necessary, derated using the Linearly Derating Methodology (LDM). Under this approach, the Peak CRC assigned to an ESR is calculated as its maximum discharge capability (MWh) in Year 4 of a Reserve Capacity Cycle (the relevant Capacity Year) divided by the applicable ESR Duration Requirement (ESRDR) for that Capacity Year.[6]

This review has examined:

- the approach to derating ESRs in other markets. (See Appendix A for the jurisdictional analysis);
- whether the LDM is consistent with the SEO; and
- alternative derating options to determine whether the existing approach should be changed.

Summary of international review

The ESR derating approaches were reviewed across five jurisdictions with capacity markets. Key market statistics and derating approaches are summarised in the tables below.

All reviewed jurisdictions (except Ontario) have implemented variants of the Effective Load Carrying Capability (ELCC) or Effective Firm Capacity approach (EFC) approach.[7]

[6] Refer to Chapter 2.2 for details on how the ESRDR is calculated.

[7] The WEM has implemented the Last-In Fleet ELCC approach to derate CC3 technologies.

Table 5: Summary statistics by jurisdiction reviewed

	WEM[8]	Great Britain (GB)	PJM (USA)	ISO New England (ISO-NE) (USA)	Ireland (Northern Ireland and Ireland)	Ontario (Canada)
Storage Capacity	1.325 GW	6.87 GW	5.17 GW	330 MW	1.11 GW	264 MW
% Storage relative to total system capacity	18.5%	9.6%	2.6%	1.1%	7.4%	0.007%
Approach	LDM	Last-in EFC	Last-in ELCC	Last-in ELCC	Last-in ELCC with least-worst regrets analysis	Derating based on historical performance

WEM and Great Britain data is for 2024.
PJM, ISO-NE, Ireland and Ontario data is for 2023.

The ELCC and EFC approaches involve complex, iterative probabilistic simulation algorithms that model the impact of a marginal unit of capacity (from a particular technology) on the system reliability standard. While these models more accurately approximate the marginal reliability contribution of a given technology, international experience indicates that they are complex to implement and likely result in volatile capacity allocations from year to year. The issues encountered in these markets are set out in Appendix A.1.

Alternative options assessed

The WEM uses the LDM to certify the ESR Reserve Capacity, as follows:

- The certified capacity for an ESR is equal to its derated maximum charge capability divided by its ESROD;
- New ESRs receive an ESROD based on the ADG calculation (conducted under Appendix 11 of the ESM Rules), assess whether non-ESR capacity can meet demand in intervals adjacent to the previous cycle's ESRDR;
- incumbent ESRs retain their original ESROD for ten years; and
- any over-allocation of capacity to incumbent ESRs is added back into the Planning Criterion.

[8] AEMO | Market data

The LDM's performance against the SEO is compared to three variants of the ELCC approach, as follows:

- Option 1: Incorporate ESRs into the amended Relevant Level Method (RLM) for Capability Class 3 (CC3) technologies.
    - Under this option, ESRs would be included in Appendix 9 of the ESM Rules and have capacity allocated based on the Last-in Fleet ELCC approach.
    - The output of incumbent ESRs would be based on historical generation, while the output of new ESRs would be determined using a peak or unserved energy minimisation heuristic (as ESR output cannot be forecast in the same way as wind and solar technologies).
    - As with the amended RLM, Distributed Photovoltaic (DPV)-corrected reference load profiles would be developed assuming a 10% Probability of Exceedance (POE) peak and expected demand growth, using historical load curves from the previous four year.
    - The Fleet ELCC would be calculated as the lower of
        - (i) whole period fleet ELCC; and
        - (ii) average of individual year fleet ELCC.
    - The Fleet ELCC would then be allocated:
        - (i) to incumbent ESR, in proportion to their performance during Peak Individual Reserve Capacity Intervals; and
        - (ii) to new ESR, in proportion to their estimated output, modelled using either a peak or unserved energy minimisation heuristic.
- Option 2: Implement Individual ELCCs.
    - This option is similar to Option 1, but instead of using a Last-in Fleet ELCC approach, individual ELCCs would be calculated for CC3 technologies and ESR
- Option 3: Last-in Fleet ELCC with Least Worst Regrets.
    - This option is similar to Option 1 but incorporates Least-Worst-Regrets analysis to address forecast uncertainty.
    - Instead, of modelling a single four-year ELCC period, multiple POE peak demand and expected demand assumptions are combined with different load shape assumptions to create multiple load trace scenarios.
    - Under this approach:
        - (i) a Fleet ELCC is calculated for each scenario;
        - (ii) regret costs are calculated for each scenario to assess the cost of unserved energy or excess capacity if a different demand outcome occurs;
        - (iii) the Fleet ELCC associated with the lowest regret cost is selected and allocated to ESRs using the same approach as in Option 1.

Conclusion

The LDM status quo performs best against the SEO due to its simplicity, transparency and predictability.

Options 1 and 3 outperform the status quo in terms of accurately approximating reliability contribution, as these options involve sophisticated probabilistic simulation models.

Option 2 performs worse than Options 1 and 3 in this respect due to the implementation of individual ELCCs.

Under a Last-in individual ELCC approach, ESR technologies added later to the model may be assigned lower reliability contributions than ESRs added earlier. Consequently, the sum of the individual ELCCs will not necessarily equal to the Fleet ELCC.

While Options 1 and 3 perform well in estimating reliability contribution, there are several drawbacks, including:

- Implementation is likely to be highly complex and costly. These options would require replacing dynamic ESROD and ESROIs with availability requirements across all Trading Intervals (albeit with a lower level of assigned capacity, as ELCC reflects marginal reliability impact).
- Both options may result in volatility in year-on-year capacity allocations (although less than under Option 2). Experience in PJM indicates that volatile allocations to intermittent generation can create investor uncertainty and increase reliance on firm generation, contributing to higher capacity prices.
- The resulting capacity derating factors are unlikely to be easily predictable for investors and existing Market Participants due to the complexity of the methodology, increasing investment risk for ESR.

When presented with these options, Working Group and MAC members supported retaining the LDM due to concerns regarding uncertainty in capacity allocation and high implementation costs under the alternative approaches.

Given the complexity and cost of the alternatives, and the views expressed by the Working Group and MAC members, the proposed Review outcome is to retain the existing LDM approach for derating ESR capacity for the purposes of CRC.

Table 6: Evaluation of ESR derating options against the SEO

	Status Quo (LDM & ESROD)	Option 1: Fleet ELCC	Option 2: Individual ELCC	Option 3: Fleet ELCC with least worst regrets
Overall performance	Most criteria met substantially ◕	Some criteria met substantially/ most partially ◑	No criteria met substantially ○	Some criteria met partially ◔
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

The detailed evaluation of the options above against the SEO is provided in B.1.3.

2.2. The method for determining the ESROIs

ESRs that have been assigned Capacity Credits are required to be continuously available during their ESROD, which comprises contiguous Trading Intervals (ESROI) centred on the Mid-Peak ESROI.

The ESROD (and corresponding ESROIs) are recalculated for new ESR Facilities and Separately Certified Components. ESR Facilities retaining their ESROD for ten years from the date first certified under grandfathering arrangements.

AEMO determines the ESROD to apply to new ESRs by identifying the Availability Duration Gap (ADG) as part of the annual Long-Term Projected Assessment of System Adequacy (LT PASA) process. The ADG enables AEMO to determine the ESR Duration Requirement (ESRDR) and, subsequently, the Trading Periods (ESROIs) in which there is insufficient Capability Class 1 (CC1) and CC3 capacity to meet operational demand without CC2 technologies.

New ESRs are assigned an ESROD and ESROIs covering the ESRDR (including the ADG), while incumbent ESRs retain their previously determined ESROD. These grandfathering arrangements create a misalignment between the actual capacity required to meet demand during the amended ESROIs and the physical capacity of the ESR fleet to meet demand during that period. To address this, an ESR Duration Requirement Uplift is added to Limb A of the WEM Planning Criterion to maintain reliability.[9]

The most recently determined ESRDR and ESROIs for the 2025-26, 2026-27 and 2027-28 Capacity Years are summarised below.

Table 7: Summary of Peak ESROI/ESROD determination for the 2025-26 to 2027-28 Capacity Years

Capacity Year	Season	ESRDR (number of Trading Intervals)	Peak Demand Period	Indicative Mid Peak ESROI	Mid Peak ESROI (business days / non-business days)	Peak ESROD (business days / non-business days)
2025-26	Summer	8	16:00-19:30	17:30	**19:00 (amended)**	**17:30-21:00 (amended)**
	Shoulder	8	16:00-19:30	17:30	**19:00 (amended)**	**17:30-21:00 (amended)**
	Winter	8	17:00-20:30	18:30	**19:00 (amended)**	**17:30-21:00 (amended)**
2026-27	Summer	8	16:00-19:30	17:30	19:00/18:00	17:30-21:00 / 16:30- 20:00
	Shoulder	8	16:00-19:30	17:30	19:00/18:00	17:30-21:00 / 16:30- 20:00
	Winter	8	17:00-20:30	18:30	19:00/18:30	17:30-21:00 / 17:00- 20:30
2027-28 (incumbent ESR)	Summer	8	16:00-19:30	17:30	19:00/18:00	17:30-21:00 / 16:30- 20:00
	Shoulder	8	16:00-19:30	17:30	19:00/18:00	17:30-21:00 / 16:30- 20:00

[9] Clause 4.5.9(a) requires the Planning Criterion to include the calculated ESROD Uplift in determining the amount of reserve capacity needed for the system to meet its annual forecasted peak demand while maintaining SWIS frequency.

Capacity Year	Season	ESRDR (number of Trading Intervals)	Peak Demand Period	Indicative Mid Peak ESROI	Mid Peak ESROI (business days / non-business days)	Peak ESROD (business days / non-business days)
	Winter	8	17:00-20:30	18:30	19:00/18:30	17:30-21:00 / 17:00- 20:30
2027-28 (new ESR)	Summer	12	15:00 – 20:30	17:30	19:00/18:00	16:30-22:00/15:30-21:00
	Shoulder	12	15:00 – 20:30	17:30	19:00/18:00	16:30-22:00/15:30-21:00
	Winter	12	16:00-21:30	18:30	19:00/18:30	16:30-22:00/16:00-21:30

Source: Values for the 2025-26 Capacity Year are sourced from AEMO's Amendment to the Mid Peak ESROI for the 2025-26 Capacity Year .
Values for the 2026-27 and 2027-28 Capacity Years are sourced from the 2025-26 WEM Electricity Statement of Opportunities.

Technical analysis – ESR availability assessment

To assess whether the existing availability obligations for ESRs remain aligned with the SEO, technical analysis was conducted to answer the following questions:

1. When have ESRs historically been required to respond to SSEs?
2. When will ESRs be needed in the future to avoid unserved energy?

The first question was addressed through a "current-state analysis" focusing on historical SSEs.[10]

The second question was addressed through a "future-state analysis," in which ESR dispatch was modelled from 2026 to 2030 to assess when it will be required to avoid unserved energy.[11]

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[10] The approach to identifying SSEs is detailed in Appendix D. SSEs were identified using Market Advisories issued by AEMO between October 2023 and August 2025 (including the 25 August 2025 event). Market Advisories relating to energy and ancillary services shortfalls were considered to represent SSEs. Additionally, instances in which manual (non-network) constraints were applied (with no Market Advisory issued) were also considered to be SSEs.

[11] The future-state modelling was conducted by AEMO. Details of AEMO's modelling approach is provided in Appendix B.2.

The methodology used to conduct this analysis, and the detailed results are provided Appendix D.

Current state analysis – Summary

26 SSEs were identified between October 2023 and August 2025:

- 20 events occurred during summer months (December to March).
- 22 out of the 26 events occurred on Business Days.
- 23 events were triggered by extreme temperatures:
    - 20 of these events occurred during summer months
    - Low wind availability can also occur in summer, which can exacerbate system conditions during hot days.
- Most events were 3 to 4 hours in duration. Three longer duration events (6 to 10 hours) were also observed, all of which occurred during the summer months.
- 19 events started before 16:30 (the first ESROI for new ESRs assigned Capacity Credits for the 2027-28 Capacity Year). Of these, 9 started at 16:00, and the remaining 10 started before 16:00.
    - 4 of the remaining 10 events occurred when the system had less than 50 MW of ESR capacity credits available.
    - 6 of the remaining 10 events occurred when there was significant ESR capacity on the system. These events occurred after the FCESS Cost Review ESM Rule Changes.
- 25 out of the 26 events ended by or before 21:00 (within the Peak ESROIs for business days for both incumbent and new ESRs).

The six SSEs that occurred after November 2024, following the FCESS Cost Review amendments to the ESM Rules, are more likely to be genuine Low Operating Reserve conditions rather than false positives arising from Market Participants not updating their offers to place capacity “in service.” All six events occurred during the summer months (December to March).

The six events that occurred before 16:30 (and after the FCESS Cost Review ESM Rule changes) were further analysed to assess whether ESRs were required outside their ESROIs to avoid unserved energy.

The table below summarises the start and end-times of the six events along with the time that peak demand occurred on each date and the time at which the capacity margin was the tightest.

Table 8: Analysis of six SSEs commencing prior to 16:30

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

Source: AEMO analysis

The table above indicates that both peak demand and the period of highest stress time occurred just prior to the Mid-Peak ESROI. As ESRs are duration limited, dispatching them earlier in the day would have reduced their available charge, leaving insufficient capacity when it was needed most. Accordingly, the Peak ESROIs were aligned with the timing of the SSEs identified above.

Future state analysis

AEMO has modelled ESR dispatch for the 2026-27 to 2030-31 Capacity Years. The model and results are described in Appendix D.2.

In brief, AEMO conducted Monte Carlo modelling using nine reference weather years (or load shapes) and 20 forced outage scenarios per Trading Interval. This means that each Trading Interval in a Capacity Year produces 180 distinct outcomes based on variations in weather and load patterns, as well as randomised outages.

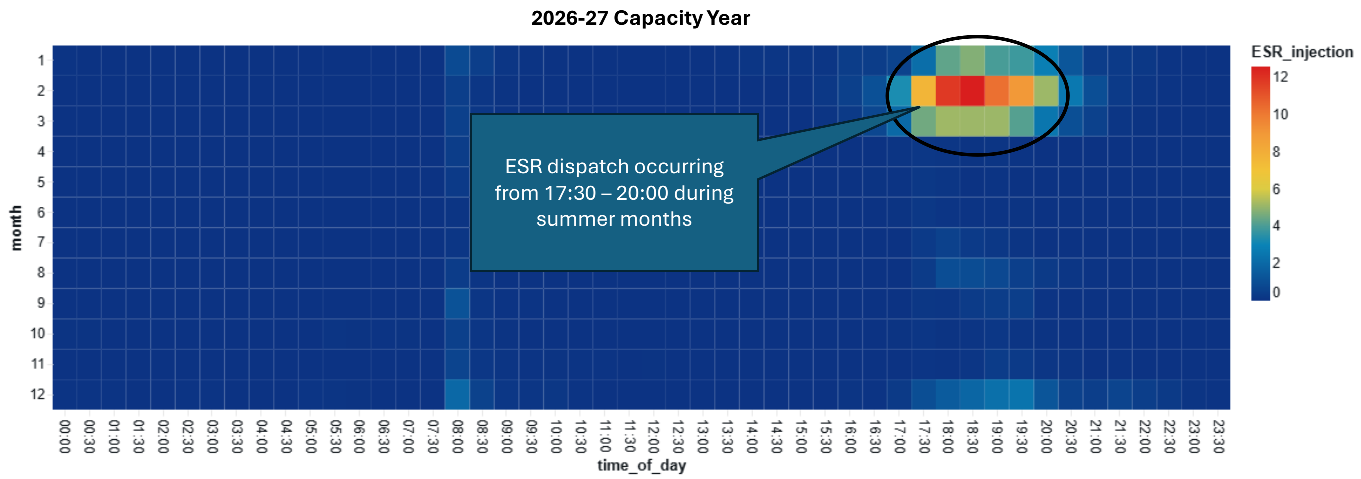
The modelling assumes that ESRs are at the top of the merit order stack (but behind DSPs), such that ESRs are dispatched to avoid unserved energy. In other words, Trading Intervals in which ESRs are dispatched would otherwise have resulted in unserved energy.

For later Capacity Years, the model assumed capacity stays flat while demand keeps rising, which artificially creates large amounts of unserved energy. This reflects a modelling limitation rather than a plausible market outcome. In practice, it is likely that the RCM would incentivise the entry of new capacity.

The heat maps below illustrate the results for the 2026-27, 2028-29 and 2030-31 Capacity Years. The calendar month is shown on the y-axis, while Trading Intervals are shown on the x-axis. Shaded cells indicate the degree of ESR dispatch (measured in average MW injection) for each combination of calendar month and time of day.

With nine reference years and 20 iterations, each trading interval is simulated 180 times. Consequently, light blue shading in the charts reflects only a very small number of occurrences and is not sufficient to indicate a credible trend.

Figure 5: Forecast average ESR dispatch by month and Trading Interval for Capacity Year 2026-27

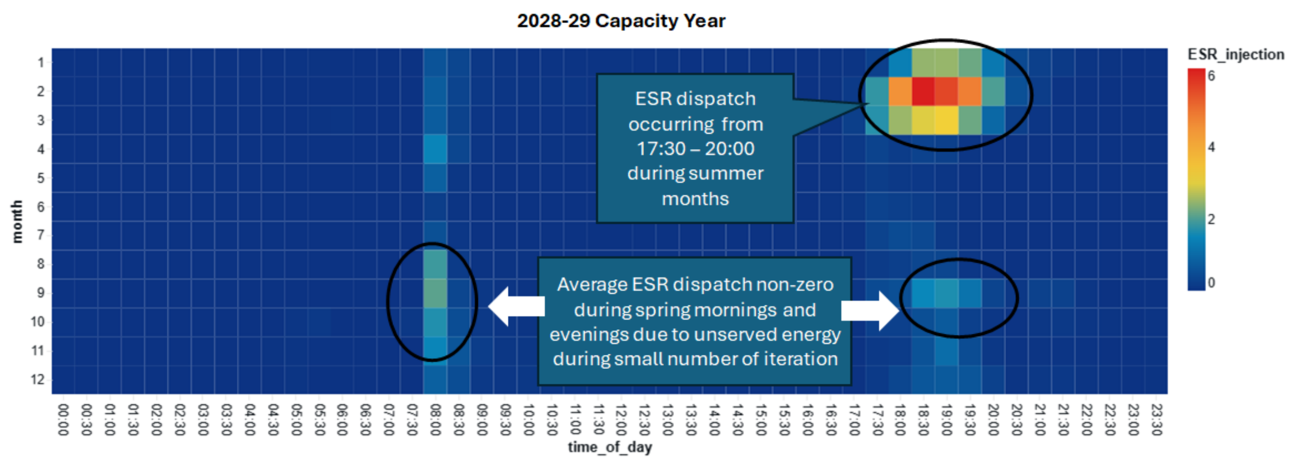


Source: AEMO modelling

As ESRs are treated as a last resort in the model, the average MW quantity of ESR dispatched represents the volume required to avoid unserved energy after all other Facilities (except DSPs) have been dispatched.

The 2026-27 results indicate that ESR dispatch to avoid unserved energy is aligned with the ESROIs for both existing and new ESRs, with discharge occurring between 17:30 and 20:00 during the January to March period.

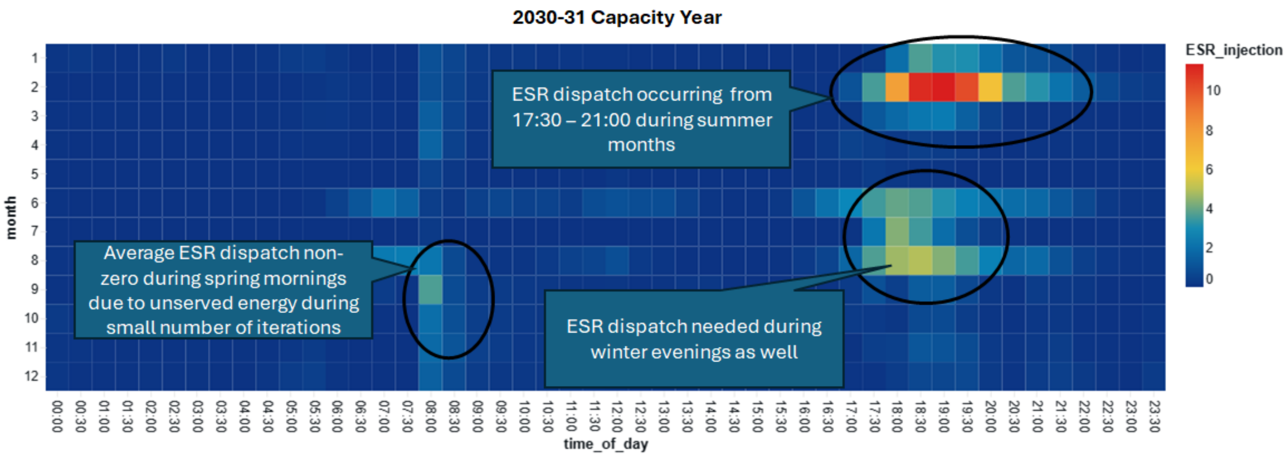
Figure 6: Forecast average ESR dispatch by month and Trading Interval for Capacity Year 2028-29



Source: AEMO modelling

In 2028-29, ESR dispatch to avoid unserved energy continues to align with ESROIs during the summer months. Some ESR dispatch is also forecasted during spring mornings and evenings. However, these very small average quantities are driven by unserved energy occurring in only a few Monte Carlo iterations. For example, if one of the 180 iterations required 300 MW of ESR injection in a Trading Interval to avoid unserved energy, this would appear in the results as an average of 1.667 MW. Accordingly, these low levels of forecasted ESR dispatch do indicate a statistically meaningful trend.

Figure 7: Forecast average ESR dispatch by month and Trading Interval for Capacity Year 2030-31



Source: AEMO modelling

By 2030-31, ESR dispatch to avoid unserved energy occurs during both summer and winter evenings, starting at 17:30. This is consistent with the planned retirement of existing coal facilities, resulting in ESRs filling the gap during winter evening peaks.

A small amount of ESR dispatch is forecasted during spring mornings, but these results are based on a limited number of iterations and therefore do not represent a meaningful trend.

Conclusions

The technical analysis yielded the following insights:

- Historically, ESRs have been required during their Peak ESROIs. While some SSEs have started before the Peak ESROIs, ESRs were best reserved for discharge during their ESROIs due to the timing of peak demand and periods of highest system stress (see Table 8).
- In the forecast period, ESRs will continue to be required during their ESROIs (17:30 to 21:00) in the summer months. As existing coal facilities retire, ESRs will also be increasingly required during their ESROI in the winter evenings (17:30 to 20:30).
- There is insufficient evidence from the modelling to conclude that ESRs will also be required during the morning period.

The technical analysis, therefore, indicates that the existing approach to setting Peak ESROIs is fit for purpose and aligned with the SEO as:

- ESR duration and availability obligations are aligned with the periods in which ESR are required to avoid unserved energy, thereby satisfying the reliability limb of the SEO.
- The ADG ensures that the Peak ESRDR increases as CC1 capacity retires, thereby, increasing the number of contiguous intervals during which ESRs must be available. At the same time, the ESRDR Uplift ensures that additional capacity is procured to account for grandfathered ESRs with lower Peak ESROD.
- The existing approach is transparent and predictable, as it is based on a known peak demand period.
- The alignment of ESROIs with system needs reduces the likelihood of AEMO needing to intervene to avoid unserved energy or procuring SC to meet demand during the summer peak demand periods.

Based on these findings, the Review outcome is to make no amendments to the existing approach for setting Peak ESROIs.

2.3. Capability Class 2 split for NAQ prioritisation

This Review considered changes to the prioritisation order within the CC2 category to determine whether it encourages hybrid technologies that may contribute greater reliability.

Capability classes are used as the first tie-break criterion (within the same step) of the NAQ method. That is, if the allocation of preliminary NAQ (within a step) results in the Peak Reserve Capacity Requirement being exceeded, AEMO must resolve the tie using the prescribed prioritisation order which prioritises the selection of CC1 facilities first, then CC3 facilities, then CC2 facilities.

In this Review, an option was assessed to determine whether sub-classes should be created within CC2 for the purposes of resolving tie-breaks. The following prioritisation order for CC2 technologies was proposed:

- hybrid facilities are prioritised over ESR only facilities (to encourage greater entry of CC3 with firming capability); and
- ESR only facilities are prioritised over DSPs (given the greater flexibility of ESR).

Table 9: Proposed prioritisation order for Capability Class 2

Type	Description
Capability Class 2(a) – Hybrid.	A Facility that includes Separately Certified Components that are over 50% Capability Class 2, with the remaining being: • Capability Class 1; or • Capability Class 3; or • A mix of Capability Class 1 and Capability Class 3.
Capability Class 2(b) –ESR only facilities.	A Facility that only includes ESR and certified as ESR.
Capability Class 2(c) –DSPs.	A Facility that is certified as DSP.

Conclusion

Information available to the Coordinator indicates that implementing the amended prioritisation order outlined above would not have changed previous NAQ outcomes. Accordingly, it is unclear whether the current NAQ prioritisation order for tie-breaking disincentivises hybrid entry.

Working Group members noted that, in the absence of a clearly identified problem, the expected material implementation costs of the proposal are unlikely to be justified by its benefits. However, some members expressed the view that DSPs should be prioritised above ESRs, as ESRs may be less effective in scenarios involving a shortfall in CC1 and CC3 capacity.

Given the associated costs and the absence of a demonstrated issue, the Coordinator has decided not to progress the proposal to create sub-classes within CC2. The Coordinator will revisit this matter if it emerges as a policy issue in the future.

2.4. Summary of items reviewed with no change proposed

It is proposed that:

- The Linearly Derated Method for assigning Certified Reserve Capacity for ESRs will be retained
- The current approach for determining Electric Storage Resource Obligation Intervals (ESROIs) will be retained.
- No changes will be introduced to tie-break different configurations of Capability Class 2 facilities within the Network Access Quantity (NAQ) prioritisation.

Consultation questions:

1. Do stakeholders disagree with any of the review outcomes outlined above? If yes, why?

3. Proposal 1 – Amend ESR Reserve Capacity Testing performance measurement rules

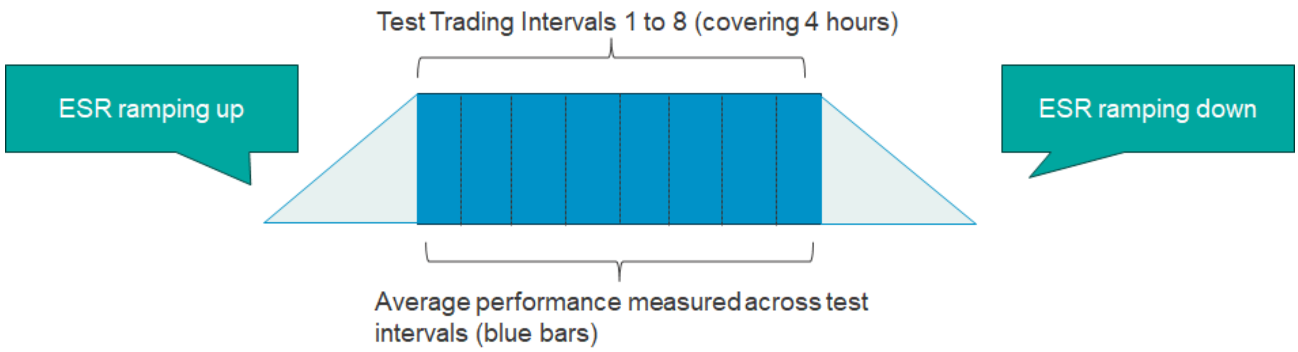
3.1. Issue with determining ESR Reserve Capacity test performance

During the Review, AEMO raised an issue with the approach to determining an ESR component's Reserve Capacity Test performance.

Clause 4.25.2E of the ESM Rules requires AEMO to assess the Reserve Capacity Test performance of an ESR as "*the average performance across its Peak Electric Storage Resource Obligation Duration based on the average performance across the Trading Intervals.*"

This clause results in a mismatch between how test performance is defined in the ESM Rules and the operational realities of testing an ESR. This is because an ESR consumes energy when ramping to its Required Level and again when ramping down to its minimum discharge depth. This is illustrated in Figure 8.

Figure 8: Example of ESR ramping up to RCOQ for Reserve Capacity Test and then ramping down



This means that, unless the ESR is oversized (i.e. able to deliver more than its RCOQ), performance during the test intervals will be lower than the ESR's average Required Level.

However, the area under the trapezium more accurately reflects the ESR's performance capability, as it measures the total energy delivered and therefore its maximum discharge capability.

It is proposed to address this issue by amending clause 4.25.2E(a) to allow AEMO to assess ESR test performance by measuring the total energy delivered (i.e. the area under the trapezium).

The Working Group and MAC supported the proposal, as it reduces the need for ESRs to be oversized solely to pass a testing requirement.

3.2. Proposal summary

The Coordinator proposes to amend the ESM Rules (including clause 4.25.2E(a)) to revise the method in which AEMO determines the Reserve Capacity Test performance of ESRs, so that total output (including ramping) is measured and ESRs are not required to be oversized to pass testing requirements.

Proposal 1

Amend the ESM Rules (including clause 4.22.2E(a)) to allow AEMO to measure the total energy delivered for assessing ESR performance during Reserve Capacity Tests.

Consultation questions:

1. Do stakeholders support amending the ESM Rules to account for ESR ramping during Reserve Capacity Tests? If not, why?

4. Proposal 2 – Amend DSP availability obligations

Demand-side response is incorporated into the WEM via the concept of DSPs. DSPs are a specific Facility Class comprising one or more Non-Dispatchable Loads (located at the same Transmission Node Identifier (TNI)) with the capability to reduce their withdrawal or increase their injection in response to an instruction from AEMO.

DSPs inherently have lower availability than CC1, CC3 facilities, as well as ESR capacity, as their availability depends on the flexibility of the associated loads. To account for these availability limitations, the ESM Rules include specific provisions prescribing when DSPs must be available, as follows:

- At the time of publication, DSPs must be available from 8:00am to 8:00pm on Business Days (clause 4.10.1(f)(vi)).
    - ESM Amending Rules to change the DSP availability obligation intervals to 6:00am to 10:00am and 2:00pm to 10:00pm have been made and will take effect upon publication of a notice in the Government Gazette.
- The maximum number of Trading Intervals during which a DSP must be available within a Trading Day must be at least 24 (i.e. 12 hours) (clause 4.10.1(iii)). This means that DSPs must be available continuously for a maximum of 12 hours (currently, within the 8:00am to 8:00pm window) if required.[12]
- DSPs must be available for a specified number of Trading Intervals within a Capacity Year. This is referred to as the Peak Demand Side Programme Dispatch Requirement. The requirement over the coming years is shown in the table below.

Table 10: Peak DSP Dispatch Requirement for Capacity Years 2025-26, 2026-27 and 2027-28

Capacity year	Peak DSP Dispatch Requirement (hours)	Peak DSP Dispatch Requirement (# Trading Intervals)
2025/26	200	400
2026/27	50	100
2027/28	23.75	47.5

4.1. Availability obligations in other jurisdictions

Five jurisdictions were reviewed to compare obligations placed on demand-side resources. The review is summarised briefly below.

[12] This requirement is analogous to CC1 technologies having a 14 hour fuel-requirement to ensure they can generate continuously during CC1 Availability Assessment Intervals (8am to 10pm)

Table 11: Capacity availability obligations in different jurisdictions (indicates residential aggregations can participate)*

Market	Participation Mode	Capacity allocation approach
Great Britain*	• Balancing Market - Demand Flexibility Services • Capacity Market • Ancillary services	Participant nominates capacity which is derated by availability factor (79% in 2024 auction).[13]
PJM* (USA)	• Energy market – as dispatchable load • Capacity market – loads can provide only capacity like WA DSPs[14] • Ancillary Services	ELCC
ISO-NE* (USA)		ELCC (Marginal Reliability Impact)
Ireland (Ireland and Northern Ireland)		ELCC (with Least Worst Regrets)
Ontario (Canada)	• Capacity Market • Industrial Conservation Initiative	Participant nominates capacity

The capacity markets reviewed all have a DSP type construct to enable demand-side participation without requiring participants to provide energy or meet a dispatch target.

In Great Britain, PJM, ISO-NE and Ireland, there are multiple modes of participation in the capacity market, depending on the capability of the loads.

Loads that can meet dispatch targets can participate in the energy, capacity and ancillary services markets. Otherwise, loads only participate in the capacity market with less onerous dispatch obligations.

In terms of duration and availability obligations, markets that have adopted the ELCC or EFC approach tend to require year around availability, with no specified upper limit on duration. However, some markets provide tailored availability windows for loads that cannot commit to year-round availability. For example:

- Ontario's approach is the closest to that of WA, in that participants nominate their available capacity and are required to be available within specific time windows. Summer resources must be available for nine hours and winter resources for five hours within defined availability windows. However, in practice, loads are typically activated for around four hours.

[13] The British regulator (OFGEM) is considering whether demand side should be incorporated into the EFC approach used to allocate capacity to ESRs and intermittent resources.

[14] Loads do not curtail - they reduce consumption through energy efficiency measures - hence no explicit curtail duration or notification requirements.

- ISO-NE allows some loads to participate on a seasonal basis within specified windows. Alternatively, loads can demonstrate demand reduction through energy efficiency measures during peak summer and winter periods.

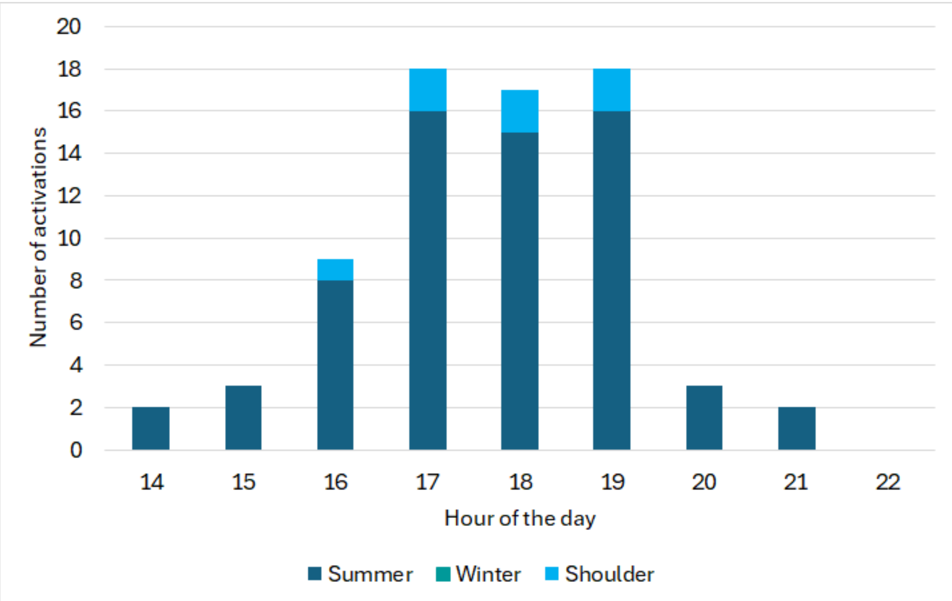
4.2. Technical analysis – DSP availability assessment

DSPs are dispatched as last-resort resources to avoid unserved energy. DSP activation events between October 2023 and February 2025 were analysed to assess the timing and duration of DSP dispatch events.

During this period, there were a total of 22 activation events, three of which include the activation of the Enel X's NCESS contract for Reliability Services. The 22 activations pertain to the Griffin DSP and three Enel X NCESS Reliability Service contracts.

Figure 9 below summarises the number of activations by hour of the day between October 2023 and February 2025. The hours of activations are presented for each event, noting that each event spanned multiple hours.

Figure 9: DSP activation events by hour of day (October 2023 - February 2025)



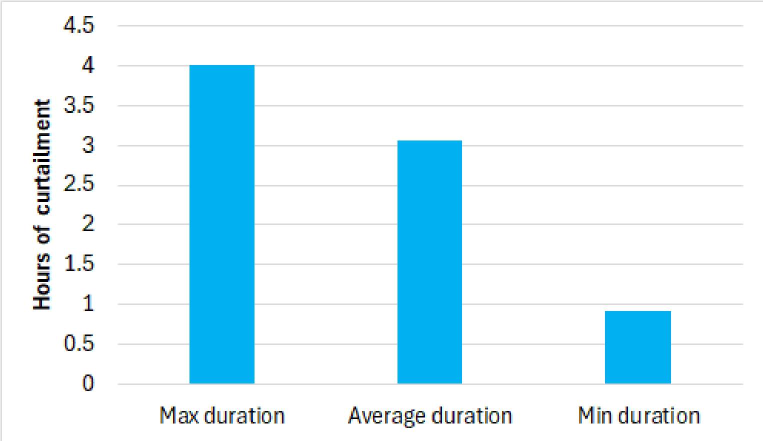
Source: [AEMO Market Data Site]

Of the 22 events, 20 occurred during the summer months and two occurred during the shoulder months. The shoulder activations relate to two DSP dispatch events on 22 November 2023 and 23 November 2023. Historically, no DSP activations have occurred during winter months.

Most events occurred between 4:00pm and 8:00pm. However, three dispatch events occurred after 8:00pm, all of which involved the dispatch of Enel X's NCESS Reliability Service contract.

Figure 10 summarises the maximum, average, and minimum duration of the DSP dispatch events described above. Dispatch events lasted an average of three hours, with a maximum duration of four hours and a minimum duration of one hour (all significantly below the 12-hour requirement).

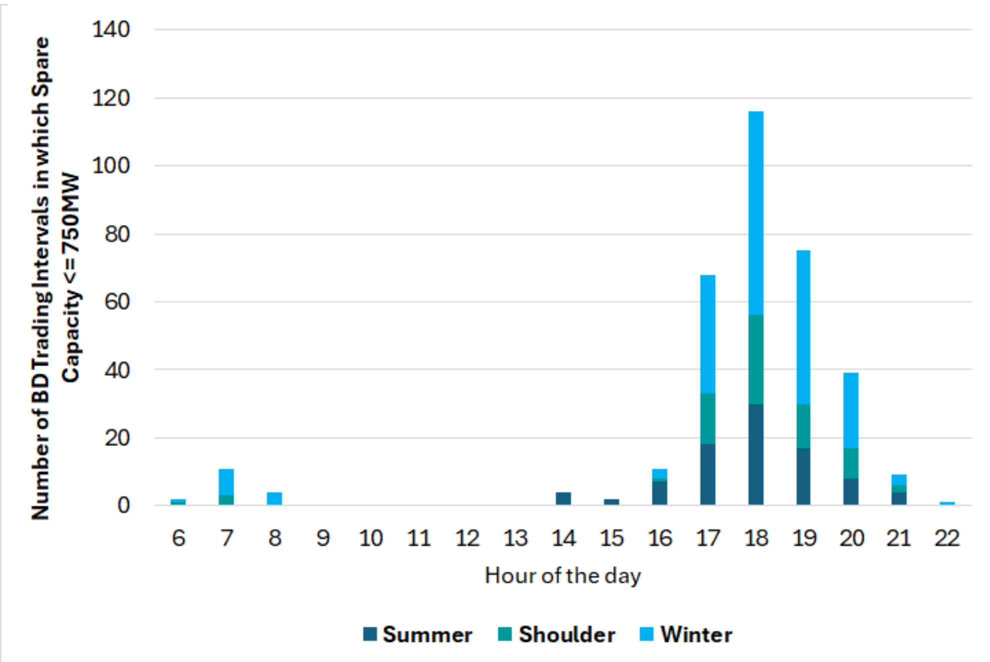
Figure 10: Duration of DSP dispatch events



Source: [AEMO Market Data Site]

As DSPs are dispatched when the capacity margin is low, the seasonal and time-of-day distribution of spare capacity was also examined. In Figure 11, spare capacity is defined in accordance with clause 4.26.1(e) of the ESM Rules (as an input to the Dynamic Refund Factor (DRF) calculation). The bars show the number of Trading Intervals in which spare capacity fell below 750 MW between 1 January 2021 and 11 October 2025. A threshold of 750 MW represents the point at which the DRF cap binds and indicates a level at which a Low Operating Reserve declaration may be triggered.

Figure 11: Frequency of spare capacity falling below 750MW by hour of the day (January 2021 - October 2025)



Source: Analysis of AEMO provided data

The vast majority of low spare capacity intervals have occurred between 5:00pm and 9:00pm. A small number such intervals are also observed between 9:00pm and 10:00pm.

A limited number of low spare capacity intervals occur between 6:00am to 9:00am. However, the spare capacity calculation does not include ESR capacity during these periods (as they fall outside the ESROIs), meaning the actual capacity margin is likely higher.

The analysis shows that:

- DSP dispatch could credibly be required between 8:00pm and 10:00pm. Hence, the existing 8:00pm cut-off is no longer appropriate.
- Historically, there have been no DSP dispatch events prior to 2:00pm. While there have been no DSP dispatch events or low spare capacity intervals between 9:00am and 2:00pm, one LRC was declared on 21 January 2025, commencing at 11:25am.
- While low spare capacity intervals have occurred during winter mornings, their prevalence is low. Further, ESRs are incentivised to discharge during such periods, as energy prices are likely to be high.

4.3. DSP availability obligation intervals - options assessed

Four options were assessed against the SEO:

Table 12: DSP availability obligation intervals options assessed against the SEO

Option	Description
Option 1: Split availability window (Tranche 8)	DSPs must be available as follows: • Available between 6:00am to 10:00am (4 hours) • Available between 2:00pm to 10:00pm (8 hours) • BTM Storage in DSPs have four hours to charge if activated in the morning (10:00am to 2:00pm)
Option 2: Split availability window (derated version)	DSPs must be available as follows: • Available between 8:00am to 12:00pm (4 hours) • Available between 2:00pm to 10:00pm (8 hours) • BTM Storage in DSPs have two hours to charge if activated in the morning (12:00pm to 2:00pm) Market Participants can choose to participate in both obligation windows or only the evening obligation (2:00pm to 10:00pm) availability window. Participants choosing the evening window receive a derated (8/12) Reserve Capacity Price.

Option	Description
Option 3: Include DSPs in ESRDR calculation	DSPs rolled into ESRDR 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 4: DSP availability obligation intervals based on Peak DSP dispatch requirement	DSP availability obligation 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

Option 2 was considered further following feedback from the MAC that the period between the morning and evening availability obligation windows does not provide sufficient time for large loads to restart their operations. Consequently, if these loads were dispatched in the morning, they would need to shut down their operations for up to 16 hours to meet the requirements.

At the 30 July 2026 MAC meeting, an alternative option was proposed by a MAC member representing Demand Side Programmes, under which the DSP availability obligation intervals would apply for 14 hours from 8:00am to 10:00pm.

At the same meeting, the two MAC members representing Contestable Customers supported retaining the existing 12 hours the DSP availability obligation intervals and expressed preference for a 4:00am to 8:00am morning window (see below), noting that this would allow loads to restart operations between the morning and evening windows.

DEED notes that the proposed option of 14 continuous intervals from 8:00am to 10:00pm would hinder the ability of BTM storage to charge between windows and discourage its participation in DSP aggregations.

4.4. Conclusion

Options 3 and 4 would significantly dilute the reliability value of DSPs to customers, as they would result in materially lower availability obligations than the existing 12-hour requirement.

- Under Option 3, new ESRs and DSPs would be subject to the same availability requirement during a Business Day. However, while ESRs must be available on all Trading Days throughout the Capacity Year, DSPs would only be required to meet the Peak DSP Dispatch Requirement.
- Under Option 4, AEMO would model the Trading Intervals in which demand in the reference demand profile (used in CC3 ELCC calculations) is likely to exceed peak demand under a 50% POE peak/median growth scenario (adjusted for DSP dispatch

and capacity). This would enable AEMO to set specific windows during which DSPs would be required (e.g. Hot Season from 3:00pm to 9:00pm). As noted above, this would likely result in materially lower availability obligations than the current 12-hour requirement and introduce year-on-year volatility for DSP participants

- Additionally, both approaches would involve moderate to high implementation complexity.

Options 1 and 2 perform similarly against the SEO. Option 1 was implemented as part of the ESM Amending (Tranche 8) Rules and will commence on a date specified by the Minister in a notice published in the Government Gazette. While Option 1 performs better than Options 3 and 4 in terms of customer value (as it retains the 12-hour requirement), several issues have been identified:

- AEMO has advised that, as the morning window obligation (6:00am to 10:00am) spans two Trading Days, this is likely to increase implementation complexity and cost;
- Working Group members noted that BTM storage is likely to be depleted at the start of the morning window obligation (having discharged the previous evening) and would therefore be unable to participate; and
- large loads have load restart limitations, meaning they may be unable to operate between the two windows, effectively requiring them to be offline for 14 to 16 hours.

Option 2 addresses the issues with Option 1 by:

- shifting the morning obligation window to 8:00am to 12:00pm so that it does not span two Trading Days, thereby reducing implementation complexity and cost;
- allowing DSP participants to choose whether to participate in both obligation windows or only in the evening obligation window. This enables the participation of large loads with restart limitations; and
- DSP participants that opt to participate only in the evening obligation window will receive a Reserve Capacity Price that is derated by 8/12 of the full price, reflecting the lower availability requirements. This derated price will flow through to the DSP's Reserve Capacity Security, reducing the security obligations proportionately.[15]

MAC and Working Group members expressed support for Option 2 on the basis that it:

- supports the participation of large, single loads within the DSP framework through the availability of a derated price; and
- minimises implementation costs by avoiding the need for availability windows that span two Trading Days.

MAC members have expressed concern that the morning window obligation does not include the period before 8:00am, as reliability shortfalls are more likely to occur during this time (relative to after 8:00am), due to lower rooftop solar output and the possibility that

[15] An alternative option to derate Capacity Credits was not pursued due to implementation complexities arising from the mismatch between the quantity of response needed from the DSP and the Capacity Credits assigned.

ESRs may not be fully charged. It is noted that there are currently no obligations for ESRs to be available before 8:00am.

As noted above, AEMO faces significant complexity and costs in implementing a morning window obligation that spans two Trading Days. Specifically, implementing a window that overlaps Trading Days would require substantial changes to AEMO's systems and processes to accommodate any split of the DSP availability hours into distinct windows. Allowing a window to cross the Trading Day boundary would break core system assumptions, resulting in increased implementation and ongoing maintenance complexity, as well as higher costs.

It is acknowledged that system stress is more likely to manifest before 8:00am (versus after 8:00am), but no such events have been observed historically. The only SSE identified in the technical analysis that commenced before 12:00pm began at 11:25am, which falls within the 8:00am to 12:00pm window proposed under Option 2.

To maintain the 12-hour requirement, an alternative to Option 2 would be to shift the morning window obligation to 4:00am to 8:00am. Additionally, any proposal to shorten the morning window obligation would need to be offset by an equivalent extension to the evening window obligation, which may introduce different challenges.

As indicated above, at the 30 July 2026 MAC meeting, Contestable Customer representatives noted that the 4:00am to 8:00am window would allow loads to restart operations between the morning and evening windows. They acknowledged, however, that it is uncertain whether many loads would be operational during the morning obligation period.

Table 13: Summary of evaluation of DSP availability obligation intervals against the SEO

	Option 1: Split window (Tranche 8)	**Option 2: Split window with derating options**	**Option 3: Include DSPs in ESROD**	**Option 4: DSP availability linked to Peak DSP Dispatch Requirement**
Overall performance	Most criteria met substantially	Most criteria met substantially	Some criteria met substantially/ most partially	Some criteria met partially
Availability obligations aligned with power system needs	Fully met	Met substantially	Met substantially	Not met
Availability obligations provide value for money	Fully met	Fully met	Met partially	Not met
Availability obligations enable value to be extracted from BTM batteries	Met substantially	Fully met	Fully met	Fully met
Approach is flexible enough to change as power system needs evolve and change	Met substantially	Met Partially	Met substantially	Met Partially
Approach is transparent and predictable	Fully met	Fully met	Met Partially	Met Partially
Cost and complexity of implementation is reasonable	Met Partially	Fully met	Met Partially	Met Partially

The detailed evaluation against the SEO is provided in Appendix E.

The proposed review outcome is to implement Option 2, as it performed best when assessed against the SEO.

Stakeholder feedback is sought on whether there is justification for the morning window obligation in Option 2 to be shifted to 4:00am to 8:00am (instead of 8:00am to 12:00pm) such that:

- the period prior to 8:00am is captured;
- the overall 12-hour availability obligation is maintained; and
- implementation complexity is reduced, as the morning window obligation would not span two Trading Days.

Consequential amendments

To facilitate DSP participation under Option 2 and simplify the certification process, the following ESM Rule amendments are proposed:

- DSPs will be allowed to associate different loads for the morning and evening windows. This will enable DSPs to form diverse portfolios of loads to meet availability obligations in both obligation windows.
- DSPs must associate loads at least three weeks prior to their proposed effective date. This is to ensure that a DSP cannot game the Relevant Demand methodology, which uses the most recent 10 Business Days or 5 non-Business Days (in which there were no DSP dispatch events) to calculate the baseline.
    - A DSP is expected to nominate its loads and, if it needs to make any changes, it may submit an updated nomination at any time before the deadline.
- DSPs that have selected one or both windows will be required to undergo Reserve Capacity Tests assessing their performance in the relevant windows.
    - For example, if a DSP selects the 8:00am to 12:00pm window, its Reserve Capacity Test should take place in that window. Similarly, if the DSP selects both windows, Reserve Capacity Tests should be conducted in both the morning and evening window.
    - Section 4.25 of the ESM Rules will require amendments to reflect this.
- DSPs will not be allowed to offer availability outside of the standard availability windows prescribed in the ESM Rules, to simplify the certification process.
    - AEMO has raised that the ESM Rules currently allow DSPs to offer availability outside the windows specified in section 4.10 of the ESM Rules. However, to date, no Market Participant has offered availability outside the required period. AEMO advised that if a participant were to offer availability outside the required window, this would add complexity and cost to the certification process.

    - To simplify the certification process, the Coordinator proposes an amendment to restrict DSP availability to the windows defined in the ESM Rules.
- Some concerns were raised by Working Group members about treating the Capacity Credits with the Derated Price as equivalent to other Capacity Credits due to them offering reduced reliability. Therefore, it is proposed that Capacity Credits allocated to DSPs who choose only the 2:00pm to 10:00pm window obligation must be traded through AEMO.
    - This proposal reflects the fact that these DSPs provide a reduced level of reliability. Therefore, these Capacity Credits should not be treated as equivalent to other Capacity Credits.

4.5. Proposal summary

The proposed Review outcome is to amend the ESM Rules to change the DSP availability obligation intervals in accordance with Option 2, to better align these with system reliability needs and encourage the participation of BTM storage by providing a charging window while minimising implementation costs.

However, to address MAC concerns about capturing the period before 8:00am, the Coordinator also seeks feedback on whether there is justification for Option 2 to be varied so that the morning window obligation is 4:00am to 8:00am (instead of 8:00am to 12:00pm).

Further proposed Review outcomes include amending the ESM Rules to facilitate DSP participation by:

- allowing DSPs the option to participate only in the evening window, to facilitate participation by large loads with restart limitations that may not be able to comply with split-window arrangements.
    - this would help maintain system reliability during periods of highest system stress, while reducing costs to consumers to reflect the DSP’s reduced reliability contribution.
    - introducing corresponding ESM Rule amendments to reflect that DSP participants that opt for the evening-only window are not providing an equivalent reliability service to other Capacity Credit holders.
- allowing DSP aggregators to associate different loads to the two sets of availability obligation intervals (for every Trading Day) to allow for greater portfolio flexibility.
- requiring Reserve Capacity Testing for DSPs to assess their performance within the applicable window.
- simplifying the certification process by specifying that DSPs are only required to be available during the availability obligation intervals specified in the ESM Rules.

Proposal 2a

Amend the ESM Rules to change DSP availability obligation intervals to 8:00am to 12:00pm (noon) and 2:00pm to 10:00pm on all Business Days.

However, stakeholder feedback is sought on whether the morning window obligation should be change to 4:00am to 8:00am.

Proposal 2b

Amend the ESM Rules to:

- allow a DSP participant to choose only the 2:00pm to 10:00pm obligation window and receive the Reserve Capacity Price derated by 8/12 to reflect the reduced reliability availability; and
- require any DSP participant that chooses only the 2:00pm to 10:00pm obligation window to trade its Capacity Credits through AEMO.

Proposal 2c

Amend the ESM Rules to:

- remove the option for DSPs to offer availability outside of the availability obligation intervals specified in the ESM Rules;
- allow a DSP to associate different loads within its portfolio to the morning and the evening sets of obligation intervals (for every Trading Day) at least 3 weeks before the associated loads effective date; and
- empower AEMO to conduct Reserve Capacity Tests in the availability obligation windows selected by the DSP.

Consultation questions:

1. Do stakeholders support the proposals for the changes associated with the DSP availability obligation intervals outlined above? If not, why?
2. Is there justification for the 4:00am to 8:00am (rather than 8:00am to 12:00pm (noon)) morning availability obligation and if yes, what is the justification?

5. Proposal 3 – Return of DSP Reserve Capacity Security if a large load ceases

During the Review, Working Group members raised an issue regarding circumstances in which a large (equal to or greater than 5 MW) Associated Load ceases operations or enters extended care and maintenance during the Capacity Year in which the related DSP has Reserve Capacity obligations.

Under the ESM Rules, the DSP would be required to associate another load at the same TNI that can provide an equivalent response. However, securing a large load that is both capable of and willing to curtail consumption at short notice at a specific TNI can be challenging and is unlikely to be successful.

Two options were considered to address this concern.

5.1. Options assessed

Option 1: Allow the DSP to recruit and associate another load at a TNI that AEMO has deemed to be unconstrained under clause 4.15.16A

Clause 4.15.16A requires AEMO to publish a list of unconstrained TNIs at which DSPs with aggregated loads (certified without a specific location under clause 4.10.1B) may locate their Associated Loads.

AEMO uses the NAQ model from the previous Reserve Capacity Cycle to identify TNIs with sufficient spare capacity to accommodate DSPs without adversely affecting the ability of other Facilities (including Energy Producing Systems) to be dispatched.

AEMO advised that, if DSPs were allowed to associate additional loads (5 MW or higher) at these unconstrained locations, then the NAQ originally assigned to those loads during certification may not accurately reflect their contribution to meeting peak demand requirements at the new location. This is because NAQ is location-specific, and a load may receive different NAQ values depending on its location.

Working Group and MAC members also expressed concern about the potential impacts on NAQ allocations for other Market Participants.

Given the risk of adversely affecting other facilities, this option was not progressed.

Option 2: Return the Reserve Capacity Security as no replacement capacity is needed

A large load that ceases operations permanently or for an extended period (e.g., entering care and maintenance) will reduce unscheduled operational demand, as it no longer consumes electricity from the SWIS.

Given this reduction in demand, if an individual large DSP Associated Load were to cease operations for an entire Capacity Year, AEMO would not be required to procure replacement capacity through the Supplementary Capacity mechanism. Accordingly, where a large load ceases operations due to factors outside the DSP participant's control, an application to AEMO to cancel the associated Capacity Credits would not be expected to adversely affect system reliability.

An alternative option, therefore, is for the DSP participant to request a reduction in its Capacity Credits, with a corresponding portion of its Reserve Capacity Security refunded, as the security would no longer be required to cover the cost of replacement capacity.

This option is relatively simple to implement and does not have adverse impacts on system reliability provided it has the following conditions in place:

- The affected DSP would be required to notify AEMO of the cessation of its Associated Load no later than 1 April in Year 3 of the relevant Reserve Capacity Cycle. This would ensure that AEMO can model the impact of the load cessation on the Reserve Capacity Requirement for the upcoming Capacity Year;
- AEMO would need to be satisfied that the cessation of operations is bona fide and will persist for the duration of the Capacity Year. Appropriate evidence would be required to support this assessment, with the evidentiary requirements set out in the relevant Reserve Capacity Security WEM Procedure;
- Associated Loads that declare cessation of operations would be ineligible to participate in Supplementary Capacity procurement for the relevant Capacity Year; and
- The policy would apply only to Associated Loads of 5 MW or greater (i.e. DSPs not subject to clause 4.10.1B), as loads must be of a material size to influence the Reserve Capacity Requirement.

MAC and Working Group members expressed concerns about treating DSPs differently from other capacity providers that are required to provide Reserve Capacity Security and are similarly subject to external factors that may affect their viability. However, when new supply-side capacity exits or fails to commence operations before the relevant Capacity Year, it results in an undersupply. Conversely, when a large load that is a DSP ceases operations before the relevant Capacity Year, it is likely to result in an oversupply.

AEMO cannot procure additional capacity without a justifiable reason. Where a new supply-side facility exits before the relevant Capacity Year, resulting in a market undersupply, AEMO would likely use the Reserve Capacity Security to procure replacement capacity and maintain system reliability.

By contrast, where a load exits, AEMO would only procure replacement capacity if the reduction in demand does not materially reduce the Reserve Capacity Requirement. A strict threshold (greater than 5 MW) is therefore required to ensure that Reserve Capacity Security is only returned where the associated reduction in demand is sufficiently large that the capacity is no longer needed to support system reliability.

The proposed Review outcome is to progress this option, subject to the conditions outlined above.

5.2. Proposal summary

Due to the NAQ implications for other Market Participants, the option for DSPs to associate a load of 5 MW or greater at another unconstrained TNI will not be progressed.

The proposed Review Outcome is to allow a DSP participant with an individual Associated Load equal or greater than 5 MW to have its Capacity Credits reduced and the corresponding portion of its Reserve Capacity Security refunded, if sufficient evidence is provided to AEMO that the Associate Load will cease operations throughout the relevant Capacity Year.

For avoidance of doubt, this policy will not apply to DSPs certified under clause 4.10.1B.

This proposal would:

- reduce the risk that a DSP provider may be disincentivised from participating in the RCM due to factors outside its control causing an Associated Load to cease operations; and
- account for any reduction in the Reserve Capacity Requirement arising from a DSP Associated Load exiting the system prior to a Capacity Year.

This proposal should be progressed, subject to appropriate conditions being applied.

Proposal 3

Amend the ESM Rules to allow a DSP participant (whose Facility was not certified under clause 4.10.1B) to have its Capacity Credits reduced and a corresponding portion of its Reserve Capacity Security returned if:

- an Associated Load greater than 5 MW ceases operations permanently or for the entirety of a Capacity Year in which the relevant DSP has Reserve Capacity obligations;
- the DSP participant notifies AEMO no later than 1 April in Year 3 of the Reserve Capacity Cycle, so that the impact of the load exit on system demand can be factored into the upcoming ESOO; and
- the relevant participant provides sufficient evidence, to be specified in the relevant WEM Procedure, that the Associated Load has ceased operations or will be offline during the relevant Capacity Year.

The ESM Rules are also proposed to be amended to prevent the Associated Load that ceased operations permanently, or on an extended basis, from participating in Supplementary Capacity for the upcoming Capacity Year.

Consultation questions:

1. Do stakeholders support the proposals to allow a DSP participant to request a reduction in its Capacity Credits and a corresponding portion of its Reserve Capacity Security returned under the above conditions? If not, why?

6. Proposal 4 – Introduce state-of-charge obligations to apply during Low Reserve Conditions

One of the issues examined by the Review was whether the RCM provides adequate incentives for an ESR to be sufficiently charged to meet the Peak RCOQs.

Chapter 2.2 of this paper sets out the technical analysis conducted to determine the characteristics of SSEs and when ESRs are most likely to be needed to avoid unserved energy.

The current-state technical analysis also reviewed ESR charge levels for a small sample of five SSEs, in which large ESR Facilities entered their ESROIs with low SOC.

These five SSEs represent periods after the implementation of the FCESS Cost Amending ESM Rules in November 2024, which addressed previous market effectiveness problems.[16]

Table 14: SOC levels of selected ESR Facilities entering their ESROIs on SSE days

#	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%	16:30
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

Source: SCADA Case Data

The charge/discharge profile of the above ESRs and the WEM energy prices during the 48 hours leading to the SSE, as well as the ESROIs on the relevant day, are illustrated in Appendix D.1.3.

[16] Wholesale Electricity Market Amendment (FCESS Cost Review) Rules 2024

Key observations include:

- Low SOC when entering SSEs or ESROIs coincide with high energy prices earlier in the day. High prices earlier in the day result in ESRs being dispatched and may prevent full recharging prior to the ESROIs.
    - For the 25 August 2025 Significant Incident, high prices were also observed, which likely contributed to the low SOC on the day.
- For all five SSEs analysed, confidential WEM refund data indicated that estimated revenue earned from discharging earlier in the day was greater than the refund paid during the ESROIs on the same day. As a result, ESRs experience a net gain after paying refunds during the ESROIs.
- As this behaviour is economically rational, it suggests that the refund mechanism may not provide a strong enough incentive for ESRs to enter their ESROIs with adequate charge levels.
    - Proposals to address the refund mechanism for ESRs are discussed in Chapter 7.
- It was also observed that dispatched FCESS quantities do not provide a clear explanation for the low ESR charge levels at the start of the SSE or the ESROIs, indicating that low charge levels do not appear to be related to FCESS dispatch.

It should be noted that the analysis identified only a small number of occurrences of this low SOC issue. However, while infrequent, such events create a PSSR risk when they occur. Therefore, it is proposed to introduce a SOC mandate within the LRC framework, enabling AEMO to issue a lack of reserve (LOR) SOC declaration that sets a mandatory charge level for the Peak Certified ESR fleet at the start the upcoming ESROI.

6.1. Proposed SOC obligation framework

The proposed Review outcome is to empower AEMO to mandate SOC for ESRs as follows:

- a SOC obligation will be included within the existing LOR framework;
- AEMO will be empowered to mandate SOC for the Peak Certified ESR fleet when it makes a LOR declaration;
- the SOC obligation will not require 100% SOC by default. Instead, the SOC required to maintain PSSR will be determined by AEMO based on prevailing system conditions and may be set at any level (e.g. 40% or 60%);
- the SOC level declared in the LOR will represent the minimum SOC level to be achieved by an ESR at the start of its ESROIs;
- the principles governing the SOC framework will be specified in the ESM Rules; and
- the ESM Rules will provide the heads of power for a WEM Procedure that sets out the details of how the SOC mandate will be operationalised.

MAC and Working Group members have expressed support for the LOR-SOC mandate but noted some concerns regarding how it interacts with FCESS and other requirements. These concerns are addressed through consequential amendments discussed later.

SOC obligation trigger

There are three types of LOR declarations that AEMO can currently make under the LRC framework (empowered by clause 3.17.11). These are summarised in Table 15.

Table 15: Description of LOR conditions

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 is elevated.

LOR2	Forecast Available Capacity is greater than: • the Forecast Operational Demand plus 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.

LOR2 and LOR3 conditions reflect actual or elevated risks of unserved energy occurring. The LOR conditions, at time of publication, indicate risks to the SWIS arising from unplanned contingencies (e.g. a network or generator trip, uncertainty in weather patterns, etc.). When AEMO uses pre-dispatch schedules to issue LOR declaration, it assumes that all available capacity that is offered will remain available.

There may be power system conditions where no LOR declarations are anticipated, assuming the ESR fleet is at a certain level of charge when entering their respective ESROIs. However, if the ESR fleet charge is below this level, there may be a credible risk to PSSR.

Therefore, it is proposed that AEMO will develop a new LOR-SOC condition that indicates a heightened risk for unserved energy if the Peak Certified ESR fleet is not at a certain level of charge at the start of the relevant ESROIs:

- The new LOR-SOC condition will apply when there is a risk that LOR2 or LOR3 conditions may arise due to insufficient ESR fleet charge.

    - It is expected that LOR-SOC conditions will be declared by AEMO before LOR 2 or 3 declarations, indicating that LOR-SOC is applied as a preventative mechanism to avoid other LOR declarations.
    - It is also expected that, in the event AEMO has not declared a LOR-SOC but subsequently declares an LOR2 or LOR3 condition, an LOR-SOC will be declared.

These changes will require amendments to clause 3.17.11 of the ESM Rules, which provides the head of power for the WEM Procedure Low Reserve Conditions, so that AEMO is empowered to amend the LRC framework to capture the LOR-SOC condition.

Approach to determining SOC obligation levels

As LOR-SOC is a preventative measure and based on AEMO advice, it is expected that the SOC obligation will be based on the LOR2 framework, with a calculated charge margin to prevent an LOR2 event.

To ensure implementation remains simple and to provide flexibility for AEMO, it is proposed that AEMO uses its existing modelling approaches to:

- Forecast the Peak Certified ESR fleet SOC level required to prevent an LOR2 condition. For avoidance of doubt:
    - A single uniform SOC level will apply across the entire peak capacity ESR fleet;
    - For ESR facilities on a partial planned outage, the SOC obligation will apply to their remaining available capacity;
    - Each ESR facility's SOC obligation will apply at the beginning of its ESROIs; and
    - As noted previously, the SOC mandate may be less than 100% and will depend on prevailing system conditions.

It is proposed that the ESM Rules do not prescribe the methodology that AEMO must use to determine the SOC obligation level. However, to provide transparency to Market Participants it is proposed that the ESM Rules require AEMO to publish its methodology in the WEM Procedure Low Reserve Condition.

In developing the methodology, it is expected that AEMO ensures that it:

- is as simple as practicable, while providing adequate certainty to Market Participants, to support transparency and cost-effective implementation;
- minimises the risk of disruption to, or intervention in, normal market processes;
- clearly shows how the required charge level is calculated and whether a tolerance range applies.

AEMO has advised that a 100% SOC would indicate that the SWIS is under severe stress, and this is unlikely to occur in practice. Therefore, a charge level below 100% should be expected. Given that this represents the minimum charge level an ESR facility must achieve, an ESR facility may have some capacity to participate in the RTM and FCESS in advance of its ESROIs.

Notification period and withdrawal

When AEMO makes LOR-SOC declaration and issues a SOC obligation, Market Participants with ESR Facilities will require:

- sufficient notice to allow adequate time to charge and adjust their operating profiles; and
- assurance that the SOC declaration is used only under genuine conditions of system stress.

The closer a declaration is made to real time, the more accurate the shortfall forecast is likely to be. However, this also reduces the time available for ESR operators to respond and charge.

Scarcity and intervention rules allow AEMO to intervene (i.e. direct) to address actual or projected energy shortfalls forecast up to one week ahead of real-time (see clause7.7.4(b)). However, forecasts made a week in advance are subject to considerable uncertainty and may not provide ESR operators with the level of confidence needed to justify operational decisions.

To balance the lead-time required for ESR operators to respond with the forecast lead-time needed to prepare sufficiently accurate forecasts, the following is proposed:

- AEMO must use best endeavours to declare the SOC obligation by 8:00pm on the Scheduling Day. This will provide longer-duration ESR facilities with sufficient time to charge.
    - This does not prevent AEMO from declaring the SOC obligation earlier. However, it is important to note that the longer the forecast lead-time, the greater the forecast error is likely to be.
- If AEMO is unable the meet above requirement despite using best endeavours, it must declare the SOC obligation no later than 8:00am on the Trading Day.
- AEMO will withdraw the SOC obligation if it determines that the LOR-SOC condition is no longer likely to apply.

Consequential amendments to Energy and FCESS offer rules

Amendments to enable ESRs to participate in RTM while ensuring compliance with SOC obligations

Issue 1: The ESM Rules currently require Market Participants to submit their capability in the quantity part of their energy and FCESS offers (where the relevant Registered Facility is accredited). This requirement is set out in clause 7.4.2(a)(i).

Working Group and MAC members have expressed concern that ESR Facilities subject to a SOC mandate may not be able to comply with both the SOC mandate and other offer and bidding requirements.

Issue 2: ESR Facilities may have different ESRDR and Peak ESROIs, depending on when they were first assigned Capacity Credits. This means that newer ESR Facilities will enter their ESROIs before grandfathered ESR Facilities (which have a lower ESRDR).

When a SOC obligation applies, there is a risk that incumbent ESR Facilities may begin charging while newer ESR Facilities are discharging. This could exacerbate system conditions, as the discharge from newer ESR Facilities may be used to charge other ESR Facilities instead of meeting peak demand.

Two options are proposed to address the issues outlined above.

Option 1: Amend the ESM Rules to empower AEMO to apply Constraint Equations to:

- constrain Peak Certified ESR facilities from being dispatched for injection before their ESROIs, unless required to provide FCESS or other services necessary to maintain PSSR on a Trading Day when an LOR-SOC condition is in effect; and
- constrain Peak Certified ESR facilities from being dispatched for withdrawal during their ESROIs and during the ESROIs of any other ESR facility, unless required to provide FCESS or other services necessary to maintain PSSR on a Trading Day when an LOR-SOC condition is in effect.

Under this option, AEMO would be allowed to violate the Constraint Equations where necessary to provide FCESS or other services required to maintain PSSR in the period before the ESR facility's ESROIs. Where this occurs, it would be taken to constitute a direction by AEMO under clause 7.7.5, thereby satisfying the requirements of clause 4.12.5(g).

Consequently, AEMO would set the RCOQ for the relevant facility to zero for the remainder of the Trading Day, preventing refunds from being calculated where a facility is unable to meet its obligations for the full ESROI.

Option 2: Amend the ESM Rules to:

- enable Peak Certified ESR facilities to offer zero energy Injection and Withdrawal quantities during Dispatch Intervals outside their Peak ESROI on a Trading Day when an LOR-SOC condition is in effect;
- prohibit ESR Facilities from charging during the Peak ESROIs of any other ESR facilities on a Trading Day when an LOR-SOC condition is in effect, except when instructed by AEMO; and
- allow an exemption where ESR facilities are instructed by AEMO for FCESS or other reliability purposes (e.g. relieving network congestion), as these actions support the maintenance of PSSR.

While Option 2 is simpler from an implementation perspective, it reduces AEMO's visibility of an ESR facility's capabilities. This, in turn, increases AEMO's reliance on manual intervention to dispatch ESR facilities in response to unexpected contingencies or for other actions required to maintain PSSR. AEMO also advised that this issue remains even if Market Participants used the "Available" flag in their market submissions under Option 2.

Under Option 1, further additions are required, including:

- AEMO would need to develop a set of Constraint Equations to prevent:
    - injection by peak capacity ESR facilities prior to their ESROIs where this would result in the facility's SOC level falling below the level prescribed by the LOR-SOC declaration; and
    - withdrawal by ESR facilities during the peak ESROI period of any other peak capacity ESR facility, to prevent charge 'cannibalisation' between ESR facilities to ensure that PSSR is not compromised.
- AEMO would be required to document the methodology used to determine and apply these Constraint Equations in a WEM Procedure.

AEMO's expectation is that this approach can be incorporated into its operational processes.

Both options deliver the same operational outcome of preserving SOC for ESR facilities during LOR-SOC conditions and preventing charge cannibalisation between ESR facilities.

Option 1 is preferred by AEMO as it provides greater visibility and more automated, transparent control through Constraint Equations. This reduces the need for ad hoc manual interventions and enables a faster response to real-time contingency events. However, it is more complex to implement, requiring more extensive amendments to the ESM Rules and requiring AEMO to design, document, and operationalise new Constraint Equations through a WEM Procedure and within its systems.

Option 2 is simpler and faster to implement, requiring fewer system changes. However, it provides AEMO with less real-time visibility of ESR facilities' capabilities and increases reliance on manual calculations and requires more involved decision-making by AEMO, which may be less efficient during contingency events.

Stakeholder views are invited on the preferred option that better balances between implementation simplicity and operational impact.

Interaction with ERA guidelines

Some MAC and Working Group members have raised that ESR energy and FCESS offers may not align with ERA guidelines, if they must comply with a SOC mandate.

As discussed earlier in this chapter, it is proposed to amend the ESM Rules to provide ESR operators greater clarity regarding how they are expected to behave and remain compliant with ERA guidelines when a SOC-obligation is imposed.

6.2. Proposal summary

The analysis shows that the system stress events that coincided with ESR facilities having a low SOC, while currently infrequent, have the potential to impact PSSR. The infrequent nature of these events does not justify a redesign of the market. Instead, targeted AEMO intervention when such events arise provides a more effective and simpler approach to implementation. As a result, it is proposed to implement a SOC mandate condition for Peak Certified ESRs within the LRC framework within the ESM Rules.

This new LOR-SOC obligation is expected to reduce the likelihood of the SWIS entering higher LOR conditions. Based on current AEMO advice, the LOR-SOC is likely to be linked to the LOR-2 framework, with the SOC level reflecting what is required to prevent an LOR2 event. The SOC level will be set at a Peak Certified ESR fleet level, with every ESR with peak ERSOIs expected to be at the mandated SOC level upon entering its respective ESROIs.

It was considered inappropriate to introduce an additional payment structure for ESRs when a LOR-SOC is declared, as these ESR facilities are already compensated through the Reserve Capacity Mechanism to make their RCOQ available during their ESROIs. Providing an additional payment would result in ESRs being compensated twice for the same service.

To facilitate compliance with the proposed LOR-SOC, it is proposed to amend the ESM Rules to provide Market Participants with sufficient time and information.

To assist Market Participants in complying with the LOR-SOC and other market submission requirements, one of the discussed options in this chapter will be implemented. Both options are expected to achieve the same outcome but differ in their implementation impacts. Stakeholder feedback is sough on which option is preferred.

Proposal 4a

Amend the ESM Rules to:

- update clause 3.17.11 (the head of power for the LRC WEM Procedure) to empower AEMO to incorporate a LOR-SOC condition into the LRC framework that applies to Peak Certified ESR:
  - the LOR-SOC condition declaration is the trigger for imposing a state of charge (SOC) obligation on the ESR fleet certified for Peak Certified Reserve Capacity.
  - The LRC WEM Procedure will also be amended to outline:
    - under what system conditions the LOR-SOC obligations will apply; and
    - the methodology AEMO will use to determine the SOC obligation level.
- allow AEMO to withdraw a LOR-SOC condition if it determines they are no longer necessary;
- specify the notification times for AEMO when declaring a LOR-SOC condition:
  - AEMO must use best endeavours to declare the LOR-SOC condition and SOC obligations by 8:00pm on the Scheduling Day; and

  - AEMO must declare the LOR-SOC condition and SOC obligations no later than 8:00am on the Trading Day,
- specify that the LOR-SOC obligation will be a uniform charge level applicable to all Peak Certified ESR Facilities, and that all ESR Facilities must be at that level at the start of their relevant ESROIs;
- specify the information that must be provided to ESR participants to provide them a reasonable level of certainty regarding the event; and
- specify that the obligation applies to the remaining available capacity of ESRs, taking outages into account.

Proposal 4b

Amend the ESM Rules to implement one of the following options.

Option 1:

- Amend the ESM Rules to empower AEMO to apply Constraint Equations to:
  - constrain ESRs from being dispatched for injection before its peak ESROIs, unless required to provide FCESS or other services to maintain PSSR on a Trading Day when a LOR-SOC is in effect;
  - to constrain ESRs from being dispatched for withdrawal during their peak ESROIs and during the peak ESROIs of any other ESRs, unless required to provide FCESS or other services to maintain PSSR on a Trading Day when a LOR-SOC is in effect;

Option 2:

- prevent ESRs from charging during their peak ESROIs and during the peak ESROIs of any other ESRs on a Trading Day when a LOR-SOC is in effect, except when AEMO instructs them for FCESS or system reliability purposes; and
- allow ESR facilities to make zero quantity offers for energy Injections and bids for zero Withdrawal outside of their peak ESROIs on a Trading Day when a LOR-SOC Charge is in effect.

Consultation questions:

1. Do stakeholders support the proposals to introduce a state of charge mandate through the introduction of new LRC – LOR-SOC)? If not, why?
2. Which option - Option 1 or Option 2, do stakeholders support to assist ESR operators in complying with a LOR-SOC obligation?

7. Proposal 5 – New charge shortfall refund to support SOC obligation compliance

As noted in Chapter 6, the five SSEs with low ESR SOC that were further analysed showed that refunds were lower than the estimated revenue earned from discharging earlier in the day. This suggests that the current refund mechanism may not sufficiently incentivise availability during these stress periods.

The proposed SOC mandate scheme will be effective in ensuring system reliability during system stress events only if the Peak Certified ESR facilities comply with the LOR-SOC condition. It is therefore important to embed incentives for compliance within the proposed LOR-SOC condition.

Compliance with the SOC obligation will be made a Civil Penalty provision. However, as potential breaches of Civil Penalty provisions are investigated and penalties are typically imposed ex post, often sometime after the event, it may be beneficial to adopt a “compliance by design” approach. This would help ensure there are no adverse impacts on PSSR at the time the system is entering, or is within, a stress period.

As the existing refund mechanism does not always provide sufficiently strong financial incentives for ESRs to be available during their peak ESROIs, changes to this mechanism were considered. However, amending the existing refund mechanism would affect all other facility types, even though the SOC obligation would only apply to ESR.

Therefore, it is proposed to introduce an addition to the current refund mechanism that applies only to ESR facilities when a SOC mandate is in effect. This approach is intended to avoid unnecessary adverse impacts on other technology types.

It is proposed to introduce a new feature into the existing refund scheme:

- ESR facilities will face higher refunds amounts if they fail to comply with the SOC mandate; and
- these higher refunds will only apply where AEMO has made an LOR-SOC declaration.

Working Group members have expressed concern that a new refund regime may entail high implementation costs. To address these concerns, and to minimise implementation complexity and cost. The following is proposed:

- refund amounts for ESR facilities will be multiplied by two when a SOC mandate is in effect. This means an ESR facility would pay twice the refund amount for failing to deliver its RCOQ compared to an ordinary Trading Day.

As this is a minor adjustment to the current refund mechanism, AEMO has advised that it would be simple to implement.

7.1. Proposal summary

A “compliance by design” framework, in addition to a civil penalty provision, is proposed to ensure that behavioural changes are embedded within the SOC mandate, recognising that these events represent periods of system stress.

An addition to the current refund mechanism for Peak Certified ESR facilities when an LOR-SOC condition is in effect is proposed to incentivise appropriate behaviour while ensuring that other technology types are not adversely affected.

The proposed refund mechanism is designed to minimise implementation costs while providing strong financial incentives for ESR facilities to comply with an LOR-SOC declaration.

Proposal 5

Amend the ESM Rules to introduce an addition to the current refund mechanism for ESRs when a LOR-SOC mandate applies.

- The refund will apply only to ESR Facilities and only when a LOR-SOC condition has been declared by AEMO.
- ESR Facilities will pay twice the amount of refunds they usually pay for failing to offer their RCOQ when a SOC obligation applies.

Consultation questions:

1. Do stakeholders support the proposals to introduce an addition to the current refund mechanism to apply only when a LOR-SOC is in effect?

Appendices

Appendix A. Jurisdictional analysis of ESR derating approaches

This appendix sets out the approach to derating ESRs participating in capacity markets across five jurisdictions: Great Britain, PJM (USA), ISO New England (ISO – NE) (USA), Ireland (including Northern Ireland), and Ontario (Canada).

Key insights from the review are summarised first, followed by detailed descriptions of the ESR derating approaches used in each jurisdiction.

A.1 Key points of interest

A.1.1 ELCC/EFC approaches are the method of choice but have resulted in unexpected complexities

Distinction between EFC and ELCC

While the EFC and ELCC approaches to derating appear similar, there are subtle differences between them.

Both approaches use probabilistic modelling to simulate system reliability and measure a non-firm resource's reliability contribution by adding an increment of that non-firm resource and determining the resulting change in system adequacy. However:

- Under the EFC approach, the non-firm resource's contribution is measured by adding an *equivalent quantity of firm capacity to get the same change in system adequacy* that was observed when the non-firm resource was added. The derating factor here is given by the quantity of additional firm capacity added divided by the quantity of non-firm capacity added.
- Under the ELCC approach, the non-firm resource's contribution can be measured one of two ways:
    - By adding the *same quantity firm capacity as the non-firm resource* and comparing the change in system adequacy (relative to the base case) with the change in system adequacy when the non-firm resource is added. The derating factor equals the change in system adequacy when the non-firm is added compared to when the firm resource is added; or
    - By adding *increments of demand* to the base case until the relevant reliability standard binds. The derating factor here is given by the quantity of demand added back by the quantity of non-firm resource that was added.

Great Britain uses the EFC approach to quantify the reliability contribution of storage and intermittent generation resources (jointly referred to as non-firm resources). By contrast, PJM, ISO-NE and Ireland all use variants of the ELCC approach.

First-in vs last-in variants

One of the issues with both the EFC and ELCC approaches is that derating factors can differ depending on whether the non-firm resources are added first, or added last:

- Under a first-in approach, system adequacy is first measured with only an increment of non-firm capacity added. The remainder of the fleet is then added, and the resulting change in system adequacy is measured.
- Under a last-in approach, system adequacy is first measured using the entire fleet (excluding the non-firm resource). The non-firm resource is then added, and the resulting change in system adequacy is measured.

If new non-firm resources have generation profiles that are correlated with those of existing non-firm resources (e.g. wind farms located in the same area), the last-in approach will result in lower derating factors than would otherwise apply to the new non-firm resource fleet. This is because the new resource's contribution to reliability coincides with the same periods during which the existing non-firm fleet contributes to reliability. By contrast, if the generation profile of the new resource is negatively correlated with that of the existing fleet, it will receive a higher derating factor because it can contribute to system reliability during periods when the existing fleet cannot.

The converse applies under the first-in approach: adding correlated new resources first results in those resources receiving higher derating factors than would otherwise apply, and vice versa.

All applicable jurisdictions reviewed in this report use the last-in EFC or ELCC approach. Interestingly, Ireland attempted to address the underestimation of new storage derating factors arising from the last-in approach by introducing a scaling factor that could be applied to the ELCC derating factor to ensure that new storage resources were appropriately compensated. However, this resulted in new storage resources being overcompensated. Consequently, the storage adjustment factor was removed.

Jurisdictions using the ELCC/EFC approach have modified (or plan to modify) initial implementations as bedding-in issues have been discovered

One of the key issues with EFC/ELCC approaches is the considerable complexity associated with these methodologies. Most of the markets reviewed have identified issues that have required changes to modify the existing approach:

- In Great Britain, two issues have been identified with the existing EFC approach:
    - The existing approach results in a misalignment between the aggregate contribution of all storage resources to system reliability and the sum of the modelled individual storage contributions. This is a consequence of the issues discussed previously.
    - The existing approach has also resulted in steep increases in EFC values for long-duration storage resources. This, combined with the ability of storage providers to self-declare capacity in the auction, has resulted in some

participants to declare durations that exceed their nameplate duration to receive a higher capacity allocation.

- To address the issues identified, Great Britain is moving to a scaled approach under which EFCs are calculated for both individual storage facilities and the storage fleet as a whole. The individual EFCs are then scaled proportionally so that their sum equals the EFC calculated when the storage fleet is modelled as a single resource.
    - However, a drawback of this approach is that it no longer results in the economically efficient level of storage being procured. Under the unscaled first-in EFC approach, the EFC reflects the marginal value of adding storage to the system.
    - In economic theory, this marginal value also corresponds to the profit-maximising price signal facing a producer. Therefore, provided the current EFC methodology values the marginal contribution of storage at the point where supply meets demand (i.e. the market-clearing point of the Capacity Market auction), the resulting incremental EFC should reflect an economically efficient market outcome.
- In PJM, the application of ELCC has resulted in two issues.
    - First, the approach has resulted in volatile allocations of capacity due to ELCCs changing materially from one capacity cycle to the next.[17]
    - Second, the use of ELCC has resulted in intermittent generation and storage resources receiving lower capacity allocations than would have been the case under a simpler methodology.
- At the time of publication, PJM was facing a supply crunch due to generator retirements and forecasts of higher demand. The lower capacity contributions assigned to intermittent generation and storage resources meant that additional capacity needed to be procured to satisfy the reliability standard. The resulting supply shortage contributed to capacity price spikes in the July 2024 auction. PJM is currently facing legal challenges from market participants in relation to these issues.
- Ireland has made two changes to its ELCC approach.
    - The first is the removal of the storage adjustment factor discussed previously.
    - The second is a shift from gross demand forecasting to net demand forecasting when applying the ELCC, to better maintain the correlation between weather and demand. This issue is discussed later.

ELCC/EFC approaches do not require durational availability obligations to be defined

The WEM uses the linearly derating approach to derate storage resources. The derating factor is a function of the storage resource’s charge level degradation and the length of the

[17] This issue has been addressed in the WEM (with respect to the future implementation of ELCC to replace the Relevant Level Method) by calculating a fleet ELCC (instead of calculating ELCCs for each individual resource) and then allocating that ELCC across intermittent resources to reduce year-on-year volatility.

ESROD. This means that AEMO must model these durational requirements to determine the intervals during which storage must be available for (i.e. the ESROIs).

By contrast, ELCC and EFC approaches quantify a resource's contribution to overall system reliability. Hence, there is no need to model durational requirements explicitly (i.e. identify the intervals during which storage resource must be available). Therefore, while the ELCC and EFC approaches are significantly more complex than the LDM approach, adopting either approach would eliminate the need for separate duration modelling.

A.1.2 Forecasting capacity requirements is becoming increasingly challenging leading to capacity market changes in some jurisdictions

Historically, system reliability was largely driven by discrete outage events of short duration. Power systems also had low levels of intermittent generation and high levels of dispatchable firm generation. This made determining capacity requirements to meet a reliability standard relatively simple.

As the penetration of intermittent generation and storage increases, system reliability is becoming more influenced by weather conditions than by discrete outage events. In a decarbonised system, periods of low solar and wind availability may result in insufficient energy being available to charge storage resources, leading to potential energy shortages that can last from hours to days.

The increasing complexity of forecasting capacity requirements has led to changes in two of the reviewed markets:

- ISO-NE is moving from its three-year-ahead Forward Capacity Market to short-term Prompt Auctions. These auctions will occur twice a year (summer and winter) and will occur one to two months before the relevant delivery period.
    - This represents a significant change, as capacity auctions have traditionally been conducted several years ahead of delivery to allow sufficient time for new facilities to be developed and constructed. This change appears to have been driven by a desire to improve the accuracy of capacity requirement forecasts.
- Ireland has changed its approach to demand forecasting as part of its ELCC modelling. The Irish Transmission System Operator (TSO) develops demand forecast scenarios based on alternative assumptions regarding peak demand, energy demand, and load shapes. Previously, the TSO used gross demand forecasts (which did not exclude intermittent generation) and modelled the existing intermittent generation fleet on the supply side when constructing the base case for the ELCC methodology.
    - As a result, the correlation between demand and weather-driven intermittent generation was not fully captured. To address this issue, the TSO is moving to a net-demand modelling approach, under which historical intermittent generation is removed from demand forecasts before load shapes are developed.
    - The ELCC methodology is then applied by adding increments of intermittent generation to the base case and measuring the resulting change in system

adequacy. This approach preserves the correlation between demand and weather-driven generation.

A.1.3 Additional incentives and penalties are an option to incentivise performance during extreme stress events

PJM has a strong financial incentives and penalties designed to promote performance during periods of system stress. The rewards and penalties under this framework only apply during Performance Assessment Intervals (PAIs). PJM determines these intervals retrospectively, after low-reserve conditions or emergency system conditions have been declared.

- Resources that fail to deliver their obligation quantities during the PAIs are charged a penalty that is a function of their shortfall, and the Cost of New Entry (CONE) used to set the capacity price.
- Load serving entities that failed to procure sufficient capacity during the PAIs are also charged a penalty.
- Resources that over-deliver relative to their obligation are rewarded with a bonus payment funded by the penalties collected from the offending entities described above.

PJM operates the above scheme in addition to a capacity refund mechanism similar to that used in the WEM. As a result, capacity providers not only have a financial incentive to meet their capacity obligations throughout the year but also face additional incentives to perform during emergency conditions.

By contrast, the WEM's incentive structure for Demand Side Programmes (DSPs) is significantly stronger than that applying to equivalent Non-Retail Behind-the-Meter Generation (NRBTMG) units in PJM. NRBTMG units do not face direct financial penalties for non-availability. Instead, their future capacity allocations are reduced by a proportion of their under-delivery in the subsequent capacity cycle.

The effect of these weaker incentives was evident during Winter Storm Elliott in 2022, when more than 300 NRBTMG units failed to deliver 1,524.1 MW of the capacity for which they had received accreditation.[18]

A.1.4 Power system challenges associated with storage does not appear to be an issue yet

None of the jurisdictions reviewed have identified any storage-specific power system security challenges.

The two main issues identified are:

- Challenges in ensuring that capacity contribution methodologies accurately quantify the reliability contribution of storage in a manner that results in the economically efficient

[18] 1,524.1 MW is the sum of the two-day shortfall (888.8 MW on Dec 23 and 635.3 MW on Dec 24), as reported in the Winter Storm Elliott Recommendations and Analysis Report

deployment of storage resources that, in combination with the rest of the fleet, can deliver the required reliability standard.

- Ensuring that weather driven impacts (such as dunkelflaute[19]) are appropriately captured when modelling capacity requirements.

It is worth noting that PJM, ISO New England (ISO-NE), and Ontario all operate day-ahead and real-time security-constrained unit commitment and dispatch algorithms that perform multi-period optimisation. This enables storage charging and discharging to be optimised based on the system operator's expectations of future system conditions. Consequently, storage coordination is likely to be less of an issue than in the WEM, which relies on self-commitment and single-period optimisation.

A.2 Great Britain

Great Britain's energy system is experiencing rapid growth in energy storage penetration, with 6.872 GW of operational capacity currently installed (representing approximately 9.6% of the total installed capacity of 71.7 GW) and a further 19 GW under construction. Around 90 GW of approved battery storage projects have yet to commence construction, while approximately 61 GW of proposed projects are awaiting planning decisions. In total, Great Britain's energy storage pipeline could result in up to 170 GW of battery storage capacity being connected to the grid.

A.2.1 Key issues

The rapid increase in storage facilities connected to the grid has raised several concerns regarding Capacity Market, particularly:

- The ability of storage to self-declare their capacity and duration, combined with existing performance testing requirements, may be resulting in the under-declaration of capacity to pass testing requirements.
  - This can lead to inefficient outcomes, as the contribution of storage to system reliability may be underestimated, requiring more capacity to be procured than would otherwise be necessary if storage operators accurately declared their capabilities.
  - To mitigate the risk of under-declaration, the British Government has proposed allowing storage units to transfer all or a part of its Capacity Obligations to another party in situations they deem necessary, including to reduce their testing requirements.[20]
- The existing EFC approach to allocating capacity results in the total contribution of the entire storage being misaligned with the sum of the individual contributions of each facility. Additionally, the derating factors sharply increase for long-duration storage

[19] Dunkelflaute (or dark doldrums or dark lull) is a German term for a meteorological phenomenon where there is little to no wind or sunlight at the same time, leading to a significant drop in renewable energy generation from wind and solar power.

[20] This Secondary Trading is still part of the Capacity Market. Units can either trade before stress event or reallocating the obligation volume after a stress event.

facilities, incentivising over-declaration of duration to get a higher derating factor. These issues are described in further detail below, together with the proposed solution, which involves moving to a scaled EFC approach.

A.2.2 Capacity contribution measurement

Great Britain measures system adequacy using the Loss of Load Expectation (LOLE) metric, with capacity procured to meet a reliability standard of three hours of LOLE per year. As the penetration of renewable generation and battery storage increase, system stress events are expected to occur less frequently but persist for longer duration, particularly during periods of prolonged low wind and solar generation ("dunkelflaute"), combined with the energy-limited nature of battery storage.

Recognising that no technology is available at all times, all capacity participating in the UK Capacity Market is assigned a derating factor. Intermittent generation and storage resources are assessed using the EFC framework, which estimates the quantity of firm generation required to provide an equivalent contribution to system reliability.

Great Britain currently applies an Incremental Last-In EFC methodology, which was introduced in 2017 when storage penetration was relatively low. This approach estimates the quantity of firm capacity required to provide the same reliability contribution as an incremental unit of non-firm capacity while maintaining the reliability standard. Incremental Last-In EFC values are calculated separately for each storage duration, with storage resources exceeding nine hours automatically treated as fully firm and assigned an EFC of 100%.

However, as the storage fleet has grown, this approach has become increasingly misaligned with the contribution of storage to overall system reliability. In particular, it has resulted in inconsistencies between the sum of individual EFC values and the expected contribution of the storage fleet as a whole. It has also led to steep increases in EFC values as storage duration approaches the nine-hour threshold.

To address these issues, the National Energy System Operator (NESO) has proposed replacing the current methodology with a Scaled EFC approach. Under this approach, incremental EFC values are retained but scaled proportionally so that the aggregated individual EFC equals the EFC of the storage fleet as a whole. This results in a smoother and more proportional relationship between storage duration and EFC value.

Final capacity derating factors for storage are then calculated by multiplying EFC values by an assumed availability factor. This factor is determined by averaging the availability of pumped storage during winter peak periods over the previous seven years. NESO has recognised that relying on pumped-storage availability data is becoming increasingly outdated and is investigating the use of actual availability data from lithium-ion battery storage systems connected to the grid.

A.3 PJM

The Federal Energy Regulatory Commission (FERC) issued Order 841, which enabled battery storage resources to participate in wholesale electricity markets from December 2019. Currently, PJM has more than 375.3 MW of nameplate battery storage capacity and 4,792 MW of hydro-pumped storage, representing approximately 2.6% of total installed capacity. PJM also hosts a range of other storage technologies that participate in the energy market, including:

- Flywheel storage;
- Compressed Air Energy Storage;
- Thermal Storage; and
- Electric Vehicles.

Despite this, PJM considers itself to need significantly more energy storage capacity due to constrained supply, ongoing interconnection backlog issues, and high resource costs. PJM has more than 1 GW of storage projects awaiting connection, although the *PJM Energy Storage Outlook* report indicates that PJM will require at least 23 GW of energy storage capacity by 2040.[21]

A.3.1 Key issues

The PJM Capacity Market, which operates through a forward auction framework using the Reliability Pricing Model and locational pricing, has faced significant challenges, as highlighted by Winter Storm Elliott in December 2022 and subsequent market outcomes.

One major issue is the reliability risk posed by behind-the-meter generation, particularly NRBTMG, which failed to deliver over 1,316.1 MW during the storm. These resources are netted from load rather than directly dispatched and are subject only to reductions in future capacity allocation rather than financial penalties.

As a result, their underperformance increased system demand during critical periods and exposed a weakness in PJM's incentive framework when compared with demand-side resources, which face financial penalties for non-delivery.

A second key issue is capacity price volatility arising from supply inadequacy, most notably the sharp increase in clearing prices in the 2025/26 capacity auction, where prices rose to approximately ten times their level in the previous year's auction. This increase was driven by a combination of generator retirements, higher demand forecasts, and PJM's transition from the Equivalent Forced Outage Rate on Demand ($EFOR_d$) approach to the Marginal ELCC approach, which quantifies the contribution of individual resources to system reliability.[22]

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[21] Outlook for Energy Storage in PJM

[22] PJM's Electric Capacity Market: Background and Current Issues (congress.gov)

However, this approach has introduced greater volatility in accredited capacity values and capacity revenues, increasing investor uncertainty at a time when substantial new investment is required.

Ongoing rule changes, litigation, and auction delays have further intensified stakeholder concerns that the current Capacity Market design may distort price signals and undermine resource adequacy during periods of greatest system stress.

A.3.2 Capacity obligations and incentives

PJM's Capacity Market operates under the Reliability Pricing Model, which includes a Performance-Based framework designed to incentivise reliable delivery during emergency system conditions. Capacity providers are assessed during declared PAIs, when system reliability is most at risk.

Resources that underperform relative to their committed capacity incur non-performance penalties calculated using the Net Cost of New Entry (Net CONE) (i.e., the benchmark cost of adding new capacity to the system). Similarly, Load Serving Entities (LSEs) face deficiency charges if they fail to procure sufficient capacity. Conversely, resources that exceed their performance obligation receive bonus performance credits, which can offset penalties or generate additional revenue.

Following Winter Storm Elliott, PJM initiated a review of these arrangements, focusing on the adequacy of rewards and penalties framework, strengthening accreditation requirements through winterisation and fuel assurance measures, improving testing rules, and reassessing the participation model for NRBTMG, whose poor performance highlighted weaknesses in the existing incentive structure.[23]

A.3.3 Capacity contribution measurement

As noted above, PJM measures the marginal contribution of storage and other non-thermal resources using a Last-In ELCC approach. Storage resources are grouped into specific ELCC classes based on duration and configuration, and their physical capability is expressed as the "Accredited UCAP (Unforced Capacity)".

The ELCC methodology uses a probabilistic risk model to assess the contribution of renewable generation and storage resources to system reliability relative to firm capacity. It does this by testing how small additions of "perfect" firm capacity and equivalent storage capacity affect Expected Unserved Energy (EUE) while maintaining the reliability standard of one day of LOLE in ten years. The resulting ratio is used to determine the ELCC Storage Class Rating.

In addition to the ELCC class rating, PJM applies a Resource Performance Adjustment factor to account for the performance of individual resources during high-risk weather conditions and high-risk hours, based on historical data. This factor compares a resource's

[23] Historically, capacity obligations related to summer seasons. However, changing weather and demand patterns means that system stress events can occur in winter as well (for extended periods of time). Winterisation of requirements ensures availability of capacity providers for both summer and winter events.

weighted availability against its class average. Together, the ELCC Class Rating and Resource Performance Adjustment are used to calculate a resource's Accredited Unforced Capacity (UCAP).

Although the Marginal ELCC approach improves the accuracy of valuing resources during periods of system stress, it has introduced greater volatility in accredited capacity values and capacity costs. PJM acknowledges that this may increase consumer costs in the short term but considers this to be justified by the longer-term reliability and efficiency benefits that the approach is intended to deliver.

A.4 ISO New England

Following FERC Order 841, ISO-NE was required to enable energy storage resources to participate in all wholesale electricity markets, including the Real-Time Energy Market, Day-Ahead Energy Market, and Forward Capacity Market.

In response, ISO-NE launched the Energy Storage Device (ESD) Project in 2019, introducing new participation models for storage, including continuous storage facilities (CSF), such as batteries, that can simultaneously provide energy, reserves, and regulation services. These reforms were supported by changes to market rules and tariffs and have contributed to rapid growth in storage participation, increasing grid-scale battery storage capacity from just 19 MW in 2018 to approximately 330 MW currently in operation.

A.4.1 Key issues

ISO-NE's capacity market was initially designed to ensure reliability during periods of summer peak demand, on the assumption that this would also be sufficient to meet winter peak demand. However, modelling undertaken by ISO-NE and the External Market Monitor (EMM) has shown that winter reliability risks are increasing and are driven by prolonged cold-weather events lasting days or weeks, rather than a small number of peak-demand hours.

For storage resources, this creates challenges because batteries need to be charged during these cold periods, when renewable generation may be limited. To address these risks, ISO-NE has proposed replacing its three-year-ahead annual Forward Capacity Market (FCM) auction with separate prompt capacity auctions for the summer and winter seasons, with a lead time of only one to three months before the relevant delivery period.[24]

A.4.2 Capacity contribution measurement

Under the current Forward Capacity Market, capacity is accredited to meet a 1-in-10-year LOLE reliability standard, with storage resources receiving capacity credit based on their ability to discharge at full output for two hours. While simple, the current accreditation method for storage not adequately account for the duration limitations of energy storage

[24] See Capacity Market Reforms.

resources beyond two hours. As a result, it may overstate accredited capacity and increase the risk of insufficient capacity being available to meet the reliability standard.

The proposed methodology uses a last-in ELCC approach to calculate the Marginal Reliability Impact (MRI) of a resource in both summer and winter seasons (i.e. so ELCC is recalculated separately for the summer and winter auctions). Prompt Auctions will use the concept of Qualified Marginal Reliability Impact (QMRIC) to better reflect a resource's expected performance during the forecasted system risk periods. Separate formulas are used for summer and winter (or seasonal) QMRIC calculations. These seasonal QMRIC components represents the reliability contribution of the resource within the summer and winter season.

The seasonal MRI of storage resources is calculated differently for existing and new resources.

- For existing storage resources, MRI is estimated by incrementally increasing storage capacity in the system model and measuring the resulting reduction in EUE during the summer and winter seasons, expressed relative to the change in qualified capacity.
- For new storage resources, a proxy resource approach is used. A small quantity of representative storage is added to the model, the resulting seasonal reductions in EUE are calculated and allocated between the summer and winter seasons. This approach avoids distortions that may arise from the limited operational history of new resources.

The MRI methodology is designed to better capture seasonal reliability risks, particularly the growing challenge of ensuring winter resource adequacy.

A.5 Ireland (Ireland and Northern Ireland)

Since the first Battery Energy Storage System (BESS) was energised in 2018, Ireland's total installed storage capacity has grown substantially. According to *EirGrid and SONI's Ireland's Resource Adequacy Assessment 2025-2034*, there is now 1,110 MW (1.11 gigawatts) of operational storage capacity (about 7.4% of total capacity), comprising:[25,26]

- 440 MW with less than 1-hour storage duration;
- 290 MW with 1-2 hours of storage; and
- 380 MW with more than 2 hours of storage.

A.5.1 Key issues

Battery Storage units currently face several challenges within the Integrated Single Electricity Market (I-SEM) framework due to system and market design limitations. Existing market and system platforms do not fully accommodate the operational characteristics of battery storage, preventing the proper registration of battery facilities and the submission of negative physical notifications for charging. Batteries are also treated similarly to pumped storage under the Trading and Settlement Code, despite their greater flexibility and faster

[25] All-Island Resource Adequacy Assessment 2025-2034

[26] EirGrid operates and develops the electricity transmission system, while SONI plans the development of onshore electricity system

response capabilities. This misclassification leads to inefficiencies in scheduling, dispatch, and settlement, while existing technical data fields do not accurately reflect key battery parameters such as storage quantities, cycle efficiency and charging intent.

To address these issues, EirGrid and SONI proposed changes to the Trading and Settlement Code to enable the full and efficient participation of battery storage within the Balancing Market.[27] The Balancing Market reflects the actions taken by the TSO to maintain the system balance and determines the imbalance settlement prices based on differences between scheduled and actual demand.[28]

A.5.2 Capacity market, obligations and incentives

The I-SEM is the wholesale electricity market for Ireland and Northern Ireland, designed to align the all-island power system with European market frameworks. It comprises day-ahead, intraday, and balancing energy markets, alongside a Capacity Market that secures long-term system adequacy through competitive auctions held up to four years ahead of delivery, with additional auctions closer to real time. BESS can participate across the energy markets, the Capacity Market, and the Delivering a Secure, Sustainable Electricity System (DS3) System Services programme, which supports the secure operation of the power system at high levels of renewable generation.

Capacity providers that clear the auctions must meet strict capacity obligations, requiring them to be available and deliver energy through the day-ahead, intraday, and balancing markets. When market prices exceed a predefined strike price, intended to reflect the cost of the most expensive generator, providers must pay the difference between the market reference price and the strike price, known as the Difference Charge.[29]

This mechanism incentivises capacity providers to prioritise reliable availability over speculative profits during scarcity events, while shielding consumers from extreme price volatility by delivering stable capacity costs. To manage financial exposure, provider liabilities are capped through the “Annual and Billing Stop-Loss Limit Factors”, balancing strong performance incentives with protections against excessive financial risk.

A.5.3 Capacity contribution measurement

Derating accounts for the fact that not all capacity is continuously available due to factors such as planned and unplanned outages, maintenance, operational constraints, and the variability of weather-dependent technologies such as wind and solar generation. Derating factors, determined by the TSO based on historical availability, size, and technology type, adjust the qualified capacity of each participant. Final auction outcomes are then determined by a Demand Curve established by the Regulatory Authorities, which incorporates locational

[27] SDP Stakeholder Presentation

[28] In Ireland the TSO is EirGrid and SONI

[29] Capacity-Market-A-Helicopter-Guide-to-Understanding-the-Capacity-Market.pdf and Capacity-Market-The-Quick-Guide-to-Understanding-Qualification.pdf

and reserve considerations for regions including Northern Ireland, Ireland, and the Greater Dublin Region.[30]

Ireland uses a combination of the last-in-ELCC method and a least-worst regrets approach to derive derating factors for all technologies (including storage), with the objective of minimising the maximum cost associated with either over procuring or under-procuring capacity.

The detailed process used by the TSO can be summarised as follows:

- Step 1 – Define net demand scenarios: The TSO develops multiple demand scenarios based on different combinations of peak demand forecasts, energy demand forecasts, and load shape assumptions.
- Step 2 – Define Capacity Adequate Portfolios (CAPs): For each demand scenario in a set, TSO models a range of potential generation portfolios capable of meeting the reliability standard of three hours of LOLE per year. These portfolios are generated using assumptions about the existing generation fleet and expected future capacity additions. Any portfolio resulting in a LOLE of three hours per year is deemed a CAP.
- Step 3 – Determine the reliability contribution: The TSO adds a specific technology and size of resource (e.g. a 100 MW, two-hour battery) to each Capacity Adequate Portfolio, then increases demand until the LOLE returns to three hours per year. The marginal derating factor is calculated as the ratio of the increase in demand to the additional capacity added, producing derating curves by technology and demand scenario.
- Step 4 – Calculate excess EUE and excess capacity: For each demand scenario, the TSO simulates its CAP under all other demand scenarios to estimate excess EUE and excess capacity. These outcomes are then monetising using the Value of Lost Load (VoLL) for unserved energy and CONE for excess capacity, allowing regret costs to be calculated.
- Step 5 – Select least-worst-regret outcome: This regret calculation is repeated for all demand scenarios, and the scenario with the lowest maximum regret cost is selected. The associated derating factors and derated capacity requirement are then applied in the capacity auction.

A.6 Ontario

As of September 2025, IESO reported 264 MW of storage capacity (representing less than 1% of their total installed capacity), mostly consisting of pumped storage. It is anticipated that Ontario's energy system will have 26 battery storage facilities with a combined capacity of 2,916 MW by year 2028.

[30] In Ireland the Regulatory Authorities consist of the Commission for Energy Regulation (CER)

A.6.1 Key issues

The *Effective Load Carrying Capacity of Energy Storage* paper investigated the capacity value of storage resources, and has stated the following issues: [31]

- Capacity Value, that is, the ability of storage resources to store energy and inject it into the system when needed. This is expected to decline as storage penetration increases, because duration-limited storage cannot sustain output during extended peak-demand periods.
- Short-duration storage can only respond to brief demand peaks. Consequently, system security and reliability may be at risk during prolonged periods of high demand.
- An increase in storage penetration may also increase competition for limited surplus energy available for charging, thereby increasing the risk that battery storage resources will not be fully charged when required.

A.6.2 Capacity obligations

To participate in the Capacity Auction Market, an energy storage resource must be a non-committed, connected, and dispatchable facility that is registered prior to the obligation period. Capacity market participants are required to submit dispatch data and demonstrate their ability to meet capacity obligations through a Capacity Test.

For storage resources, this requires submitting offers and injecting energy at or above the greater of their cleared Installed Capacity (ICAP) or minimum loading point for four consecutive hours. Successful performance is defined as delivering at least 95% of cleared ICAP on average. Failure to meet this requirement results in non-performance charges.

A.6.3 Capacity qualification calculation

The UCAP that a storage resource can offer is calculated by applying an availability derating factor and a performance adjustment factor to its ICAP. ICAP is defined as the lesser of the Energy Rating divided by a duration of four hours and the Full Power Operating Mode.

For storage resources, the availability derating factor is based on a fixed EFORd of 5%, while the performance adjustment factor reflects the resource's capacity test results and is subject to a minimum value of 0.75.

UCAP values are calculated and assigned by the system operator. However, the current methodology is under review to better reflect the diminishing marginal contribution and duration effects of increasing storage penetration.

[31] IESO Resource & Plan Assessment Technical Paper: Effective Load Carrying Capability of Energy Storage | August 2025

Appendix B. DSP market mechanisms and obligations in other jurisdictions

This Appendix sets out the various market mechanisms that enable the participation of Demand Side Programmes, together with their respective obligations, across the five jurisdictions reviewed in Appendix A: Great Britain, PJM (USA), ISO New England (USA), Ireland (Ireland and Northern Ireland), and Ontario (Canada).

B.1 Great Britain

Demand Side Response (DSR) in Great Britain is defined as the ability of consumers to adjust their electricity consumption in response to price signals or incentive payments. Customers with either large-scale or small-scale assets may participate as DSR units, subject to the following conditions:

- Large-scale assets with the technical capability to meet National Energy System Operator’s (NESO's) metering, telemetry, and performance requirements may register directly in the market.
- Small-scale assets, such as domestic batteries, electric vehicles, or flexible commercial loads below 1 MW, must participate through an aggregator.

DSR units can provide any of the following services: Demand Flexibility Service (DFS), Capacity Market services, and Non-Balancing Mechanism services.

B.1.1 Demand Flexibility Services

Demand Flexibility Services (DFS) is a relatively new initiative that commenced during winter 2022/2023. DFS aims to incentivise homes and businesses to shift demand by reducing their electricity consumption or changing the times at which they use electricity.

Under this mechanism, the System Operator (NESO) assigns settlement periods during which a reduction in consumption is required, providing at least 48 hours’ notice. Registered DFS participants can bid to reduce their electricity consumption during these periods, which typically have an average duration of (more or less) one hour.

DFS does not require complex telemetry systems or real-time control of the participating facility. Households with smart meters and businesses with half-hourly metering may voluntarily participate through their electricity retailers.

Currently, no penalties are incurred by customers who have signed up to provide DFS services but fail to reduce their consumption. Non-compliant customers are simply required to pay for their usual electricity consumption and do not face any additional financial consequences.

Between November 2022 and March 2023, 20 trial events and two live events were conducted, resulting in a total energy reduction of 3.3 gigawatt hours (GWh) across Great Britain. Approximately 2.6 million households and businesses were also able to earn revenue through this service during the winter of 2023/24.

B.1.2 Capacity market

The Capacity Market in Great Britain conducts an annual auction for providers that undertake an obligation to deliver capacity when required by the system. DSR units are permitted to participate in the Capacity Market.

NESO publishes a Capacity Market Notice during a system stress event or when the capacity margin falls below 500 MW. Capacity Providers are expected to respond by delivering their committed capacity within four hours of the publication of the notice.

A key point to note for DSR units is that they are not derated using the existing EFC methodology applied in the Capacity Market. Instead, the historical availability of DSR providers participating in the Short-Term Operating Reserve (STOR) service is assessed to determine the required DSR volume. STOR is further discussed on Appendix B.1.3.

Around 677.3 MW of capacity was awarded to DSR units in the Capacity Auction for Delivery Year 2025/26. Despite this relatively high level of participation, the Government is continuing to develop reforms to the Capacity Market aimed at formally incorporating consumer-led flexibility through DSR technologies. Some of the key proposals include:

- Incorporating BTM technology classes to better quantify demand-side response;
- Developing improved derating methodologies (e.g., incorporating DSR technologies into the EFC method); and
- Reducing transaction costs for smaller capacity providers.

B.1.3 Non-balancing mechanism services

Customers can offer to increase or decrease their electricity usage or generation depending on system needs. While DFS is technically a balancing service administered by NESO, this section focuses on Balancing Mechanism (BM) services that have more stringent technical and operational requirements, including communications systems and operational metering.

Frequency response

Frequency response services require providers to respond within seconds of receiving a notice. DSR units can provide two types of frequency response: Fast Frequency Response (FFR) and Fast Reserve (FR).

- FFR service providers must respond within 2–30 seconds and sustain the response for up to 30 minutes.
- FR service providers must respond at a minimum rate of 25 MW per minute and sustain the response for 15 minutes. Consequently, the minimum capacity requirement is 25 MW.

Frequency Response Service providers are typically facilities equipped with battery storage, fast-ramping generators, or industrial processes capable of responding instantaneously to help stabilise system frequency.

Frequency Response services are typically procured through monthly tenders. However, some large generators provide mandatory frequency response through automatic changes in active power output.

In 2017, NESO procured 617 MW of DSR capacity for Frequency Response.

Short Term Operating Reserve (STOR) services

STOR providers are required to respond within 20 minutes of receiving an instruction from the System Operator and sustain their response for up to four hours. A minimum capacity requirement of 3 MW applies to all participants, including DSR units, seeking to provide STOR services.

In 2017, NESO procured 1368 MW of DSR capacity for STOR services. In the 2024 auction, approximately 79% of STOR service contracts were awarded to DSR units.

B.2 PJM

Demand Response in PJM is defined as a consumer's ability to reduce electricity consumption when wholesale prices are high or when the system requires it for reliability purposes. However, this reduction in consumption must be measured against normal operating practices or behaviour. For example, a business that does not typically operate during holiday periods would not qualify as providing demand response during those periods.

Customers can participate in demand response programmes through a Curtailment Service Provider (CSP), which implements the necessary equipment, operational processes, and systems on the customer's behalf.

There are two different types of Demand Resources in PJM: Load Management Demand Resources (Emergency and Pre-Emergency) and Economic Demand Resources.

B.2.1 Load management demand resources

Load Management Demand Resources are treated similarly to generators in the market and are expected to deliver capacity during periods of system reliability need. This category includes both Emergency and Pre-Emergency Demand Response resources.

Participants in this mechanism are subject to mandatory commitments and are required to respond to events that may occur on any day between June and May of the following year and may be of unlimited duration. Failure to comply with these obligations may result in a non-compliance penalty being imposed on the relevant participant.

PJM notifies the market when emergency demand response activation is required and then dispatches demand response resources based on the most efficient combination of availability, location, dispatch price, and the quantity of load reduction required.

Load Management Demand Resources can participate in the following markets:

- Energy Market only (Emergency Loads only);
- Capacity Market only (Demand Side Programme-like construct); and

- Energy and Capacity Markets.

CSPs are required to submit metering data to PJM to receive payment for participation. Participants receive compensation based on a combination of the applicable Reliability Pricing Model (RPM) clearing price and their committed load reduction, together with an availability payment made monthly.

CSPs may also offer Summer-Only Resources in the auction. These resources are only required to be available from June to October and during May of the relevant delivery year.

In 2024, approximately 210.0 MW of demand response capability was registered to provide regulation services through load reduction. Of this capacity, 67.8 MW was provided by batteries, while 142.5 MW was provided by electric water heaters.

B.2.2 Economic demand resources

Energy market

Economic demand response is a voluntary programme that is typically dispatched when wholesale energy prices exceed the monthly PJM Net Benefits Price (i.e., the price at which the benefits of reducing energy consumption exceed the costs of compensating Economic demand response resources).

DR units participating in the Energy Market are not subject to specific obligations regarding when they must respond or how long they must maintain their response to system needs.

Ancillary market

An Economic demand response resource may also voluntarily participate in the Ancillary Services Market to provide the following services:

- Synchronised Reserves, which requires a response within 10 minutes of a PJM dispatch instruction;
- Day-ahead Scheduling Reserves, which require a response within 30 minutes of a PJM dispatch instruction; and
- Regulation services, which require resources to respond to frequency response signals.

However, once a demand response resource has been certified to provide Ancillary Services, PJM expects the CSP to respond when dispatched to support system reliability. CSPs specify the hours during which each demand response resource may be cleared or dispatched in the day-ahead and real-time markets.

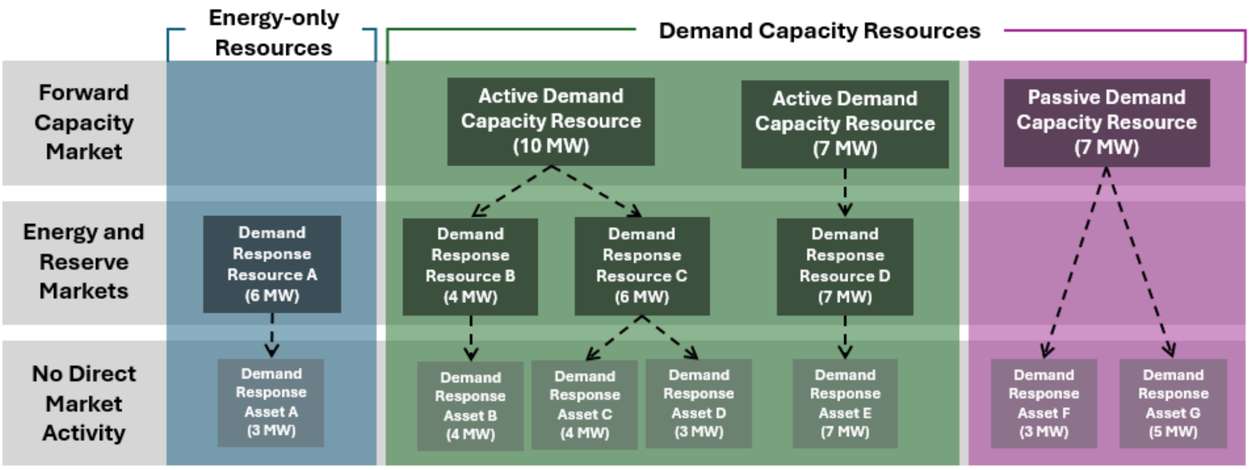
- In the Day-ahead market, a demand response resource may offer load reductions in advance of real-time operations and receive payments based on the day-ahead Locational Marginal Price (LMP) for the quantity of load reduced.
- In the Real-time market, a demand response resource may offer load reductions and receive payments based on the Real-Time LMP for the quantity of load reduced.

Compensation is based on the amount of load reduction provided. In addition, deviation charges may apply if PJM determines that the actual load reduction differs significantly from the reduction instructed or scheduled.

B.3 ISO New England

ISO New England defines demand resources as competitive assets that can reduce their electricity consumption to help ensure that the electricity supply remains sufficient, reliable, and cost-effective. There are various types of demand response that reflects a hierarchal structure, as displayed in Figure B1 and summarised below:

Figure B1: ISO-NE Market Structure for Demand Resources



Modified figure from source: [About Demand Resources (www.iso-ne.com)]

- Active Demand Capacity Resources (ADCRs) may consist of multiple Demand Response Resources.
  - ADCRs can participate in the Forward Capacity Market.
- Demand Response Resources (DRRs) may consist of multiple Demand Response Assets (DRAs).
  - DRRs can participate in the Day-Ahead and Real-Time Energy Markets, depending on their availability and the obligations of their associated ADCRs.
- DRAs are the physical assets or entities that provide the actual load reduction.
  - DRAs are not allowed to directly participate in the energy, capacity, or ancillary services markets.
  - If a DRA has a capacity of 5 MW or greater, it cannot be aggregated and must be associated with its own DRR.
  - If a DRA has a capacity of less than 5 MW, it may be aggregated within a DRR. The aggregated DRR may exceed 5 MW in capacity.
- Passive Demand Capacity Resources do not curtail in response to dispatch notifications. Instead, they achieve load reductions through energy efficiency measures implemented during specified periods.
- Passive Demand Capacity Resources can only participate in the Capacity Market. There are two types:
  - On-peak resources: may provide load reductions during summer peak periods (non-holiday weekdays from 1:00 PM to 5:00 PM in June, July, and August) and winter peak periods (non-holiday weekdays from 5:00 PM to 7:00 PM in December and January).

- Seasonal-peak resources: may provide load reductions during June, July, August, December, and January when the real-time hourly load is equal to or greater than 90% of the system peak-load forecast for the relevant season.

DRRs in ISO New England are subject to seasonal audits during the capability demonstration year (April through November for the summer season, and December through March for the winter season). The purpose of these audits is to determine the resource's ability to perform through one of the following methods:

- Dispatching the resource between 8:00 AM to 10:00 PM for a duration of one hour (12 consecutive 5-minute intervals); or
- Assessing the historical performance of the resource when dispatched on a date and start time specified by the lead market participant, for the same duration of one hour (12 consecutive 5-minute intervals).

B.4 Ireland (Ireland and Northern Ireland)

The Demand Side Management mechanism allows customers to participate by reducing their electricity consumption during peak periods or by lowering their overall electricity usage. In addition to reducing their electricity bills, participating consumers may also receive financial incentives through tariff-based schemes.

Both Ireland and Northern Ireland have established demand side management mechanisms.

B.4.1 Demand Side Unit

Demand Side Units (DSUs) are third party companies that specialise in providing demand-side services by aggregating one or more Individual Demand Sites (IDSs). These sites are typically medium- to large-scale industrial facilities that can adjust their energy consumption by generating electricity on-site, shutting down plant operations, or using a combination of both approaches. DSUs must have a minimum capacity of 4 MW to register and participate in the Capacity Market and Ancillary Services markets.

There are two operating models for DSUs:

- Peaking types are price-responsive and are only required when energy market prices are high. They are activated relatively infrequently and are typically required for a limited number of periods.
- Long-run types are expected to continuously reduce their net electricity imports from the grid. This model is commonly used by businesses that have their own generating units to meet on-site demand.

Capacity market

DSUs are awarded one-year Capacity Contracts based on the results of the Capacity Auction. In the 2023 Capacity Auction, 639 MW of DSU capacity in Ireland and 136 MW of DSU capacity in Northern Ireland were successful in the auction.

Ancillary market

DSUs participating in the Ancillary Services Market are required to receive and respond to Dispatch Instructions issued by the Transmission System Operator (TSO). If a DSU is dispatched to provide Ancillary Services, it must respond within one hour of receiving the instruction and sustain its response until the next Dispatch Instruction is issued or until the DSU's Maximum Down Time has been reached.

DSUs are also required to maintain a Performance Monitoring Error (PME), defined as the difference between the baseline response and actual performance, of less than 0.25 MWh over a full quarter-hour period.

B.4.2 Aggregated generating unit

Aggregated Generating Units (AGUs) are currently specific to Northern Ireland and had a total registered capacity of 79 MW in 2023. AGUs consist of aggregations of small diesel and gas-fired generators, each with a capacity of less than 10 MW.

Similar to DSUs, AGUs are dispatched by instructing generation across multiple sites within the aggregation. However, AGUs are not considered a demand-side response service. Instead, they are treated in a manner similar to conventional generators, as they do not alter on-site electricity consumption.

B.4.3 Forthcoming demand side mechanisms

There are several Demand Side Programmes that have either recently been introduced or are currently under development. Some of these include:

- The Dispatchable Consumption Unit mechanism aims to increase on-site electricity consumption in response to dispatch instructions and price signals from the energy market.
- The Flexible Demand mechanism, which is specific to data centres in Ireland, enables EirGrid to instruct participating data centres to reduce their electricity demand when required.
- Mandatory Demand Curtailment applies to large industrial consumers connected to the transmission network at voltages of 100 kV or greater. Under this mechanism, participants may be required to reduce their demand to pre-agreed levels when the system enters an Emergency State. A reduction in consumption of up to 50% is expected within one hour of the instruction being issued.
- Other implicit demand side response initiatives are also under development in Ireland. These mechanisms rely on indirect signals and are expected to be enabled through technological advancements and policy measures that incentivise load shifting.

B.5 Ontario

Demand Response in Ontario enables customers to reduce their electricity consumption during periods of high demand. There are two main demand response mechanisms in Ontario - the Capacity Auction and the Industrial Conservation Initiative (ICI).

B.5.1 Capacity auction

The Independent Electricity System Operator (IESO) previously operated a separate Demand Response Auction that functioned similarly to the Capacity Auction. However, this programme was discontinued, and demand response resources are now required to participate in the Capacity Auction alongside generation, energy storage, and import resources.

The capacity obligation applies over a six-month period, during which a demand response resource may be required to reduce its electricity consumption during either the summer period, the winter period, or both, for up to four consecutive hours. Demand response resources receive payments based on the auction clearing price in exchange for making their capacity available during the following periods:

- Summer period: 12:00 PM to 9:00 PM (May 1 to October 31); and/or
- Winter period: 4:00 PM to 9:00 PM (November 1 to April 30).

B.5.2 Industrial Conservation Initiative (ICI)

The ICI is intended for large industrial electricity consumers in Ontario. Participants in the ICI are compensated for shifting or reducing their electricity demand during periods of system stress. As a result, the ICI assesses a participant's average monthly maximum hourly demand, rather than its installed capability, to determine eligibility for participation in the initiative.

Participants must maintain their availability from May through April and are compensated based on their performance during the five highest system peak hours over the corresponding one-year period.

There are two classes of customers that may participate in the ICI:

- Class A (1 MW and above):
  - Customers with an average monthly demand of between 1 MW and 5 MW may opt into the ICI programme by 15 June of each year, provided they satisfy all other eligibility requirements; and
  - Customers with an average monthly demand exceeding 5 MW are automatically enrolled in the ICI programme. If a participant wishes to be excluded from the initiative, it must opt out by 15 June of each year.
- Class B (500 kilowatts (kW) to 1 MW):
  - IESO has lowered the eligibility threshold by introducing a new class of customers with an average monthly maximum demand greater than 500 kW and less than 1 MW. These customers may opt into the ICI programme by 15 June of each year; and
  - Customers with a maximum hourly demand greater than 5 MW that have opted out of the ICI programme will be treated as Class B customers. Similarly, current Class A customers that do not meet the eligibility threshold for the following year will be settled as Class B customers.

Appendix C. Evaluation for rating the capacity of Electric Storage Resources

C.1 Evaluation criteria

ESR derating options were assessed against the following criteria and outcomes, each of which is aligned with one or more of the three limbs of the State Electricity Objective (SEO).

Table C1: Evaluation criteria used to assess ESR derating options

Criteria/outcome sought	Map to SEO
Provides value for money by reasonably approximating contribution of ESRs 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.
Method is transparent and predictable.	Complex and/or opaque methods may deter investment in new batteries which could adversely affect the security & reliability, pricing and environment limbs of the SEO.
Method does not result in volatile allocation from year to year.	Uncertainty and/or 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.
Approach does not distort RCM and RTM investment signals.	The RCM and RTM provide scarcity pricing signals to investors. Policies involving frequent intervention or off-market procurement to provide the same service (e.g. getting energy/capacity through SC/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.
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.

C.2 Options evaluated

The ESR derating options evaluated are summarised in the table below. See also Chapter 2.1.

Table C2: ESR derating policy options evaluated

Option	Description
Status Quo.	Linearly Derating Methodology (degraded maximum charge capability by the relevant ESROD value). • Incumbent ESRs retain their original ESROD for ten years; and • Over-allocation of capacity to incumbent ESRs is added back into the Planning Criterion via ESROD Uplift.
Option 1: Incorporate storage into amended RLM.	Incorporate ESRs into the amended Appendix 9 (Last-in Fleet ELCC) (adopting same approach as for CC3). • ESR output for facilities that have not been operational for the full RLM Reference Period is estimated via “perfect-foresight” heuristic that allocates ESR capacity to Trading Intervals to minimise peak demand or unserved energy. • Fleet ELCC is allocated to individual Facilities in proportion to their output during the 12 Peak SWIS Intervals.
Option 2: Implement individual ELCCs.	Per Option 1, however, implement individual ELCCs for both ESRs and CC3. This would require replacing the 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).

C.3 Evaluation results

In this evaluation, the four options above are evaluated against the criteria summarised in Table C1.

C.3.1 Status quo

Table C3: Evaluation of the LDM against the SEO

Criteria	Evaluation
Provides value for money by reasonably approximating contribution of ESRs to reliability.	Does a reasonable job approximating contribution to peak period reliability but does not represent contribution to overall reliability. Grandfathering arrangements mean that the capacity allocated to incumbent ESRs does not reflect the physical capacity needed to meet demand during the Peak Demand Period. Contribution to reducing peak demand will be over-estimated if participants do not reflect their minimum charge levels (or depth of discharge) correctly at time of certification. *Criteria met partially*
Method is transparent and predictable.	The current system is reasonably simple and transparent. • The LDM component is very simple and transparent. • By contrast, the approach used to determine the ESROD is somewhat complex (but not as complex as implementing an ELCC approach). *Criteria met substantially.*
Method does not result in uncertainty or volatile allocation from year to year.	There should be no uncertainty in the LDM component as the participant will know their degradation profile ahead of time. There is an element of uncertainty for investors where the ESROD changes which would result in them receiving less capacity (than they would with a lower ESROD). However, the grandfathering arrangements address this concern. *Criteria met substantially.*
Cost and complexity of implementation is reasonable.	This approach is already implemented and therefore has no implementation costs associated with it. *Criteria met fully.*
Overall Performance.	Most criteria met substantially. 

C.3.2 Option 1: Incorporate ESRs into new RLM (Last-in Fleet ELCC)

Table C4: Evaluation of Option 1 against the SEO

Criteria	Evaluation
Provides value for money by reasonably approximating contribution of ESRs to reliability.	This approach results in a more accurate representation of the storage fleet's contribution to overall system reliability compared with the status quo. However, as the ELCC is calculated for the entire fleet and allocated afterwards, the resulting RLM of each ESR does not reflect its individual marginal contribution to reliability. This approach also discourages charging and encourages high output during high demand periods. *Criteria met substantially.*
Method is transparent and predictable.	ELCC algorithms are complex, and it is unlikely that participants will be able to predict their ELCCs unless they have the required modelling infrastructure set up. *Criteria not met.*
Method does not result in uncertainty or volatile allocation from year to year.	This approach carries some risk of changes in ELCCs year-on-year. However, as previously noted, this risk is mitigated through the use of fleet ELCCs and by calculating the Fleet ELCC over the entire ELCC Reference Period and for each individual Capacity Year within the period and taking the average. Under this approach it is likely that the capacity associated with ESRs will change year on year, albeit not as drastically as it would under an individual ELCC approach. *Criteria met partially*
Cost and complexity of implementation is reasonable.	As this option is already being implemented for CC3 technologies, the cost associated with this option relates to the additional implementation actions needed to incorporate storage. This would include: • Electricity System and Market (ESM) Rule amendments to assess ESRs under new Appendix 9; • Changes to system implementation to include storage. This would include: - Adding storage fleet calculations to the algorithm. Storage output should be negatively correlated with intermittent generation. As such, storage ELCCs can be calculated after the intermittent generation ELCCs have been calculated (for each of the Committed, Proposed, Early and Conditional categories);

Criteria	Evaluation
	- Implementing a heuristic to model the dispatch of new ESRs without historical output data.; • Refund calculations for ESRs would need to be amended to apply over all Trading Intervals (not just ESROIs) with exemptions made for charging. *Criteria met partially.*
Overall Performance.	Some criteria met substantially or most met partially. ◐

C.3.3 Option 2: Implement individual Last-in ELCC

Table C5: Evaluation of Option 2 against the SEO

Criteria	Evaluation
Provides value for money by reasonably approximating contribution of ESRs to reliability.	Like Option 1, this approach yields a more accurate estimate of the reliability contribution of individual ESRs than the status quo. However, the individual ELCC approach results in under-estimating the contribution of resources that are added later in the algorithm. This means that the sum of the individual ELCCs will not equal the ELCC of the fleet as a while. Hence, Option 1 outperforms Option 2 in terms of accuracy of fleet contribution. *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.	This option has a high risk of allocations changing materially year on year as noted by the PJM experience. *Criteria not met.*
Cost and complexity of implementation is reasonable.	This option would involve replacing the amended Appendix 9 with the new approach. Given the new RLM was widely consulted on, replacing it is not a prudent approach. Moreover, this option would be more computationally intensive as AEMO would have to repeat the analysis for individual facilities (as opposed to calculating Fleet ELCCs). *Criteria not met.*

Criteria	Evaluation
Overall Performance.	Most criteria not met. ○

C.3.4 Option 3: Implement Option 1 with least worst-regrets analysis

Table C6: Evaluation of Option 3 against the SEO

Criteria	Evaluation
Provides value for money by reasonably approximating contribution of ESRs to reliability.	The ELCC calculation approach under this option is similar to Option 1. The key difference is that the Fleet ELCCs are calculated for multiple demand scenarios, and regret costs are calculated to assess which demand scenario minimises the maximum regret cost. This method outperforms Option 1 as it has a more robust approach to incorporating the impacts of weather variation. *Criteria met fully.*
Method is transparent and predictable.	This approach is even more unclear than Option 1 due to the use of 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.*

Criteria	Evaluation
Cost and complexity of implementation is reasonable.	As with Option 2, this option would involve replacing the amended Appendix 9 with the new approach which has already been consulted on. Like the individual ELCCs, implementation would be very complex as the Fleet ELCCs have to be recalculated for multiple demand scenarios. The least-worst regrets analysis involves another round of simulations in which capacity adequate portfolios developed with a specific demand scenario are run against all other demand scenarios to calculate the regret cost. A further problem with this approach is that the Planning Criterion and therefore the Reserve Capacity Requirement is linked to the 10% POE peak demand forecast (through the first limb of clause 4.5.9). Allocating ESR and CC3 capacity using different peak and energy assumption could result in misalignment between the Reserve Capacity Requirement and capacity allocations. This could be resolved by only using demand scenarios with a 10% POE peak forecast. *Criteria not met.*
Overall Performance.	Some criteria met partially.

Appendix D. Technical analysis

The technical analysis was conducted in two stages:

- A current state analysis focused on historical system stress events (SSEs) and the historical dispatch of DSPs;
- A future state analysis (using Australian Energy Market Operator (AEMO)) modelling) to forecast when Electric Storage Resources (ESRs) will be required to avoid unserved energy in the near future.

The scope, methodology and detailed results are presented in this appendix.

D.1 Current state analysis

The current-state technical analysis examined historical SSEs to understand the following:

- When do SSEs typically occur in terms of time of year and time of day?
- How long do SSES typically last?
- What were the charge levels of ESRs prior to entering their ESROD on SSE days?

D.1.1 What is a system stress event?

SSEs were identified by reviewing AEMO Market Advisories and Manual Constraints issued between November 2023 and August 2025 (including the Significant Incident of 25 August 2025), using the following approach:

- Market Advisories containing Low Reserve Condition (LRC) declarations were used as the primary indicators of SSEs;
- Market Advisories relating to energy and ancillary services shortfalls were also considered indicative of SSEs;
- Manual (non-network) constraints applied by AEMO were reviewed to identify additional events not captured by Market Advisories;
- SSE start times were based on the start time specified in the most recent advisory relating to the event, allowing any changes in event timing to be captured;
- SSE end time were based on the end-time specified in the most recent advisory relating to that event;[32] and
- SSEs that were resolved without Directions or load shedding were excluded.

This process resulted in a final dataset comprising 26 confirmed SSEs.

Table D1 shows the types of Market Advisories and Manual Constraints that were included and excluded.

[32] Note that: SSE duration (end time - start time) doesn't necessarily reflect how long ESRs would be required.

Table D1: Inclusion and Exclusion of Market Advisories and Manual Constraints

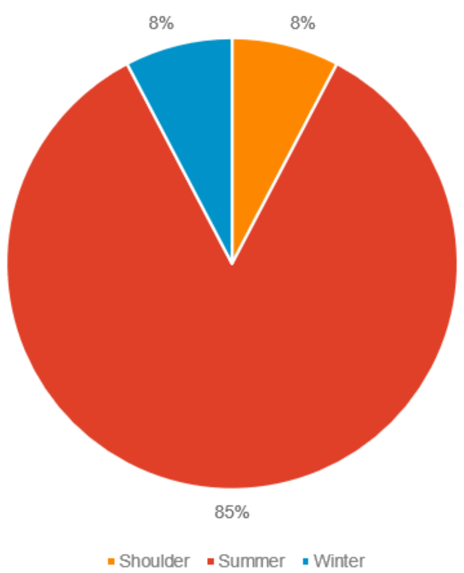
Dataset	Includes	Excludes
Market Advisories. 25 SSEs identified.	Energy & ancillary services shortfalls.	• Non-shortfall events (transmission or comms events); • Minor manual constraints; • Ramp rate shortfalls; • Emergency of High-Risk Operating State advisories; due to system instability; and • Network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

D.1.2 Characteristics of SSEs

Seasonality and causes of SSEs

While SSEs are often associated with summer conditions, the analysis showed that they were not exclusively a hot-season phenomenon, with 16% of events occurring during shoulder and winter months. Figure D1 shows the seasonality breakdown of the 26 identified SSEs.

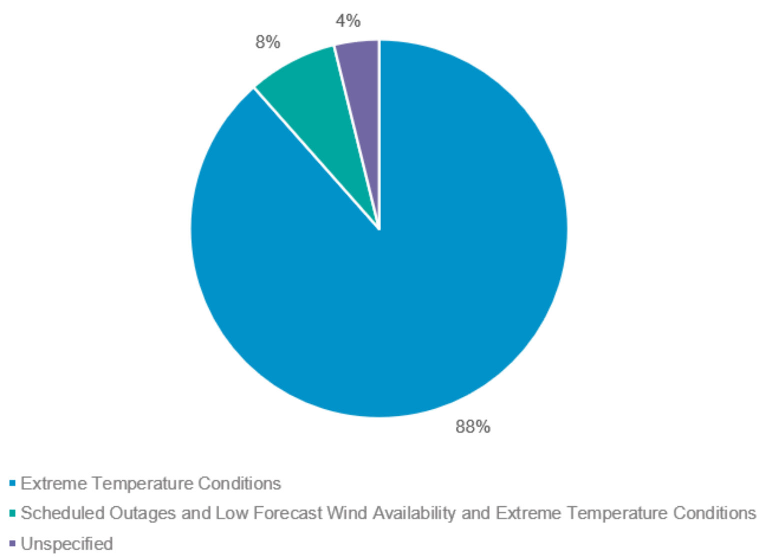
Figure D1: Seasonality of SSEs



The majority of SSEs also occurred on Business Day, with only 4 out 26 events occurring on non-Business Days.

The majority of events (88%) were triggered by extreme temperatures, most commonly high summer temperatures. While 8% were triggered by a combination of high temperatures, low wind availability and scheduled outages. Figure D2 shows the percentage breakdown of the main causes of the 26 SSEs

Figure D2: Common Causes of SSEs



Timing of SSEs

Figure D3 shows the number of SSEs on Business Days by Trading Interval, comparing their start and end times against the current 2025-2026 Electric Storage Resource Obligation Interval (ESROI) (applied to incumbent ESR) and the future 2027-2028 ESROI (to be applied to new ESRs).

Most SSEs on Business Days began earlier than 17:30 (the start of the first ESROI applicable to grandfathered ESRs).[33] The six-hour Electric Storage Resource Obligation Duration (ESROD) (commencing at 16:30) provides better coverage of these events; however, 19 of the 26 SSEs still commenced before 16:30.

As noted in Chapter 2.2, an SSE starting prior to the ESROD does not necessarily mean that AEMO would have required ESR dispatch to avoid unserved energy. Although many of these events began before the ESROD, peak demand and the tightest capacity margins generally occurred during the Mid-Peak ESROI, indicating that the existing ESROIs are broadly aligned with periods of system need.

[33] All four SSEs that occurred on Non-Business Days started before 16:30.

Figure D3: Start and End Times of SSEs that occurred on Business Days

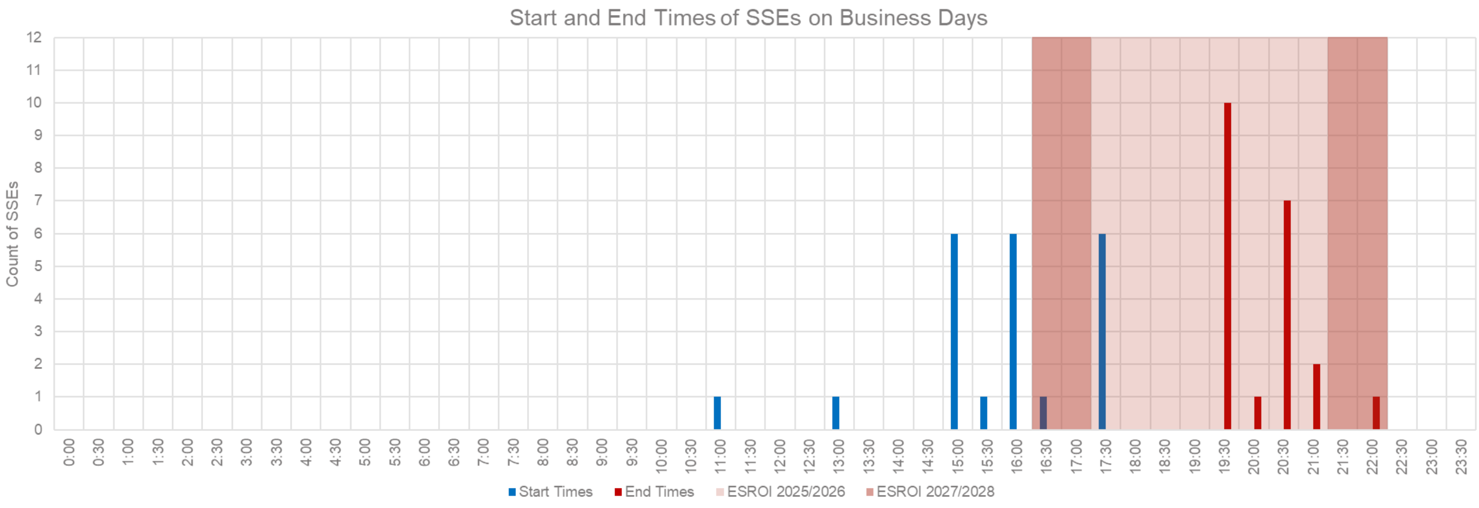
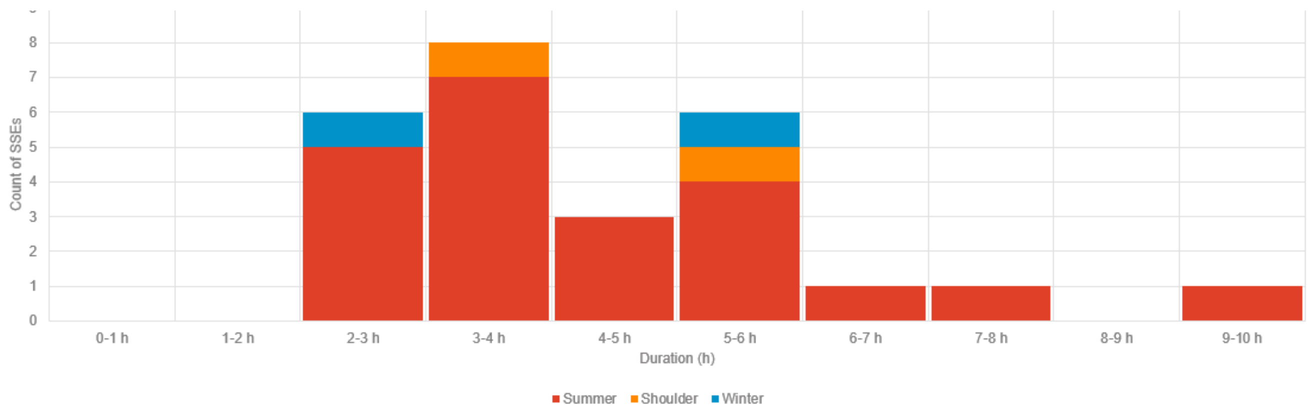


Figure D4 summarises the distribution of SSE duration. Most SSEs are relatively short, typically lasting three to four hours. Three longer duration events (6 to 10 hours) were also identified, all of which occurred during the summer months. While longer-lasting events do occur, they are considerably less common and are most likely to occur during summer.

Figure D4: SSE duration by season



D.1.3 Analysis of ESR behaviour in the 48 hours leading up to the SSE

Frequency Co-optimised Essential System Service (FCESS), Energy dispatch, and Wholesale Electricity Market (WEM) Energy price data was analysed to determine whether any trends in ESR charging and discharging behaviour could be identified. This analysis was undertaken to access ESR charging behaviour during their ESROIs on SSE days.

The data used to conduct this analysis is summarised in Table D2 below.

Table D2: Datasets used to conduct analysis

Data	Description	Source
Supervisory control and data acquisition (SCADA) Case data.	Details of the state of charge for each ESR.	Market Surveillance Data Catalogue (MSDC) Database.
Facility Energy Dispatch schedule quantity.	Details of available capacity and energy dispatch by facility.	MSDC Database.
Facility Regulation Raise enablement quantity.	Details of regulation raise dispatch by facility.	MSDC Database.
Facility Regulation Lower enablement quantity.	Details of regulation lower dispatch by facility.	MSDC Database.
Facility Contingency Raise enablement quantity.	Details of contingency raise dispatch by facility.	MSDC Database.
Facility Contingency Lower enablement quantity.	Details of contingency lower dispatch by facility.	MSDC Database.
WEM Dispatch Solution data.	Only WEM energy prices data was analysed.	AEMO market data website.

The period analysed was 48 hours prior to the start of each SSE (across the 26 identified SSEs) until the end of each SSE. Five SSEs in the sample included instances where large ESR Facilities were at below 50% charge either at the start of the SSE or the first ESROI.

For the five SSEs selected for further analysis, Table D3 below shows the dates, start times, end times, and ESR charge levels. For the SSE that commenced after the start of the ESROI (28/08/2025), the charge level of COLLIE_ESR1 was below 50% both at event start and ESROI start.

Table D3: 5 SSEs with low ESR Charge Level

#	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

To investigate the factors contributing to the low charge levels observed during the five SSEs identified above, FCESS enablement quantities and WEM energy prices over the preceding 48-hour period were analysed to identify any common drivers of charging and discharging behaviour.

Relationship between FCESS enablement and charge levels

Figures 17 to 19 show the relationship between FCESS enablement quantities and SSEs #2 to #4. These SSEs occurred after the implementation of the FCESS Cost Review ESM Rule Changes, and SSE #2 encompasses most of the 48-hour period preceding SSE #5.

To note about SSE #2:

- it occurred on 10/12/2024 from 15:00 to 20:30, with KWINANA_ESR1 having 42% charge level at event start; and
- SSE #2 was caused by extreme temperature conditions (heatwaves)

All figures should be interpreted in the same way. For example, Figure D5 illustrates FCESS enablement quantities compared with the charge level of KWINANA_ESR1 during SSE #2, where:

- the figure covers the period from 24 hours prior to the start of the SSE through to the end of the SSE;
- the orange shaded area indicates the duration of the ESROI

- the yellow shaded area indicates the portion of the SSE occurring before the ESROI; and
- the lines represent FCESS enablement quantities (Regulation Lower, Contingency Lower, Regulation Raise, and Contingency Raise), measured in MW.

A review of FCESS enablement and charge-level patterns across multiple SSEs showed no clear relationship between low charge levels and FCESS dispatch. This result is consistent with expectations, as an ESR charge level only needs to support FCESS dispatch for the subsequent five-minute interval. As a result, an ESR can be enabled to provide FCESS across a wide range of charge levels.

Figure D5: FCESS quantities for SSE #2 on 10/12/2024

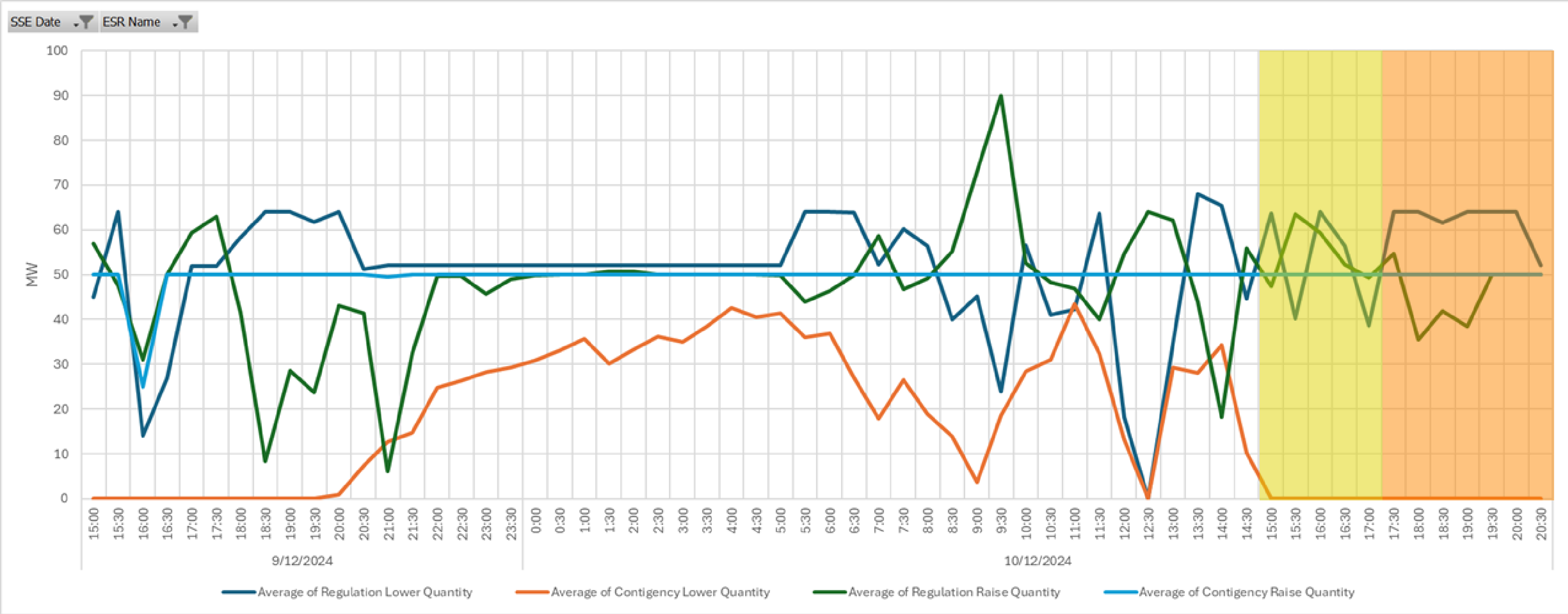


Figure D6: FCESS quantities for SSE #3 on 23/1/2025

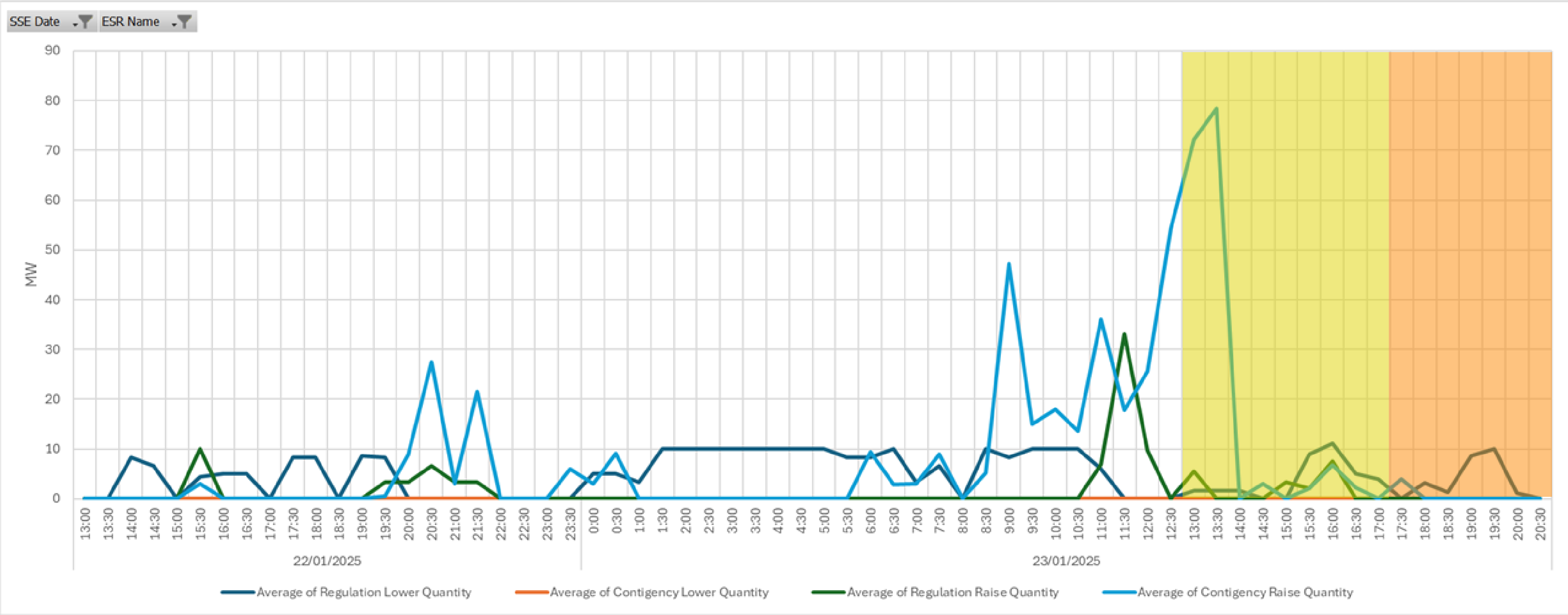
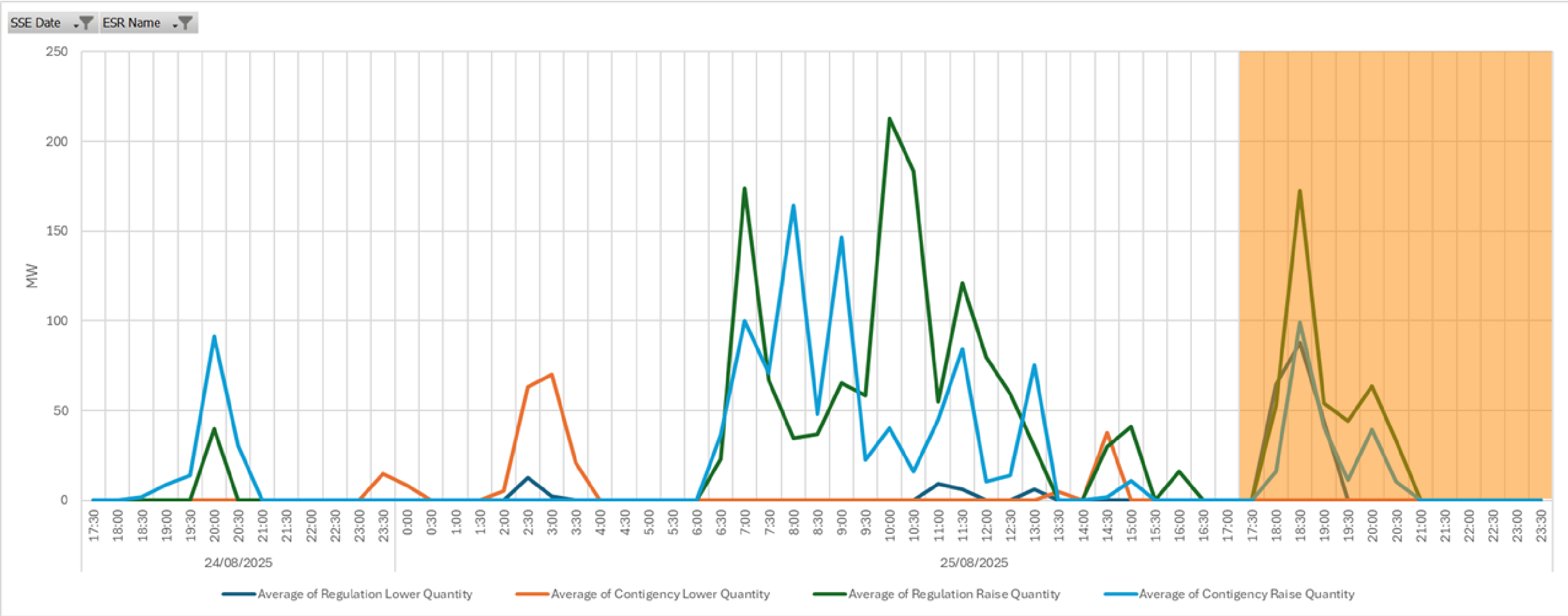


Figure D7: FCESS quantities for SSE #4 on 25/8/2025



Relationship between FCESS enablement and WEM Energy Prices

WEM energy price data was also analysed for the five SSEs and compared with individual ESR charge levels at the start of these events.

The following graphs compare ESR charge level with WEM energy prices for the five of the identified SSEs:

- 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;
- yellow shaded areas indicate the portion of the SSE occurring before the ESROI;
- pink lines represent WEM Energy Prices (AUD/MWh); and
- dark green lines represent the ESR charge level.

Figure D8: ESR charge levels vs. WEM Energy Price for SSE #1 on 13/01/2024

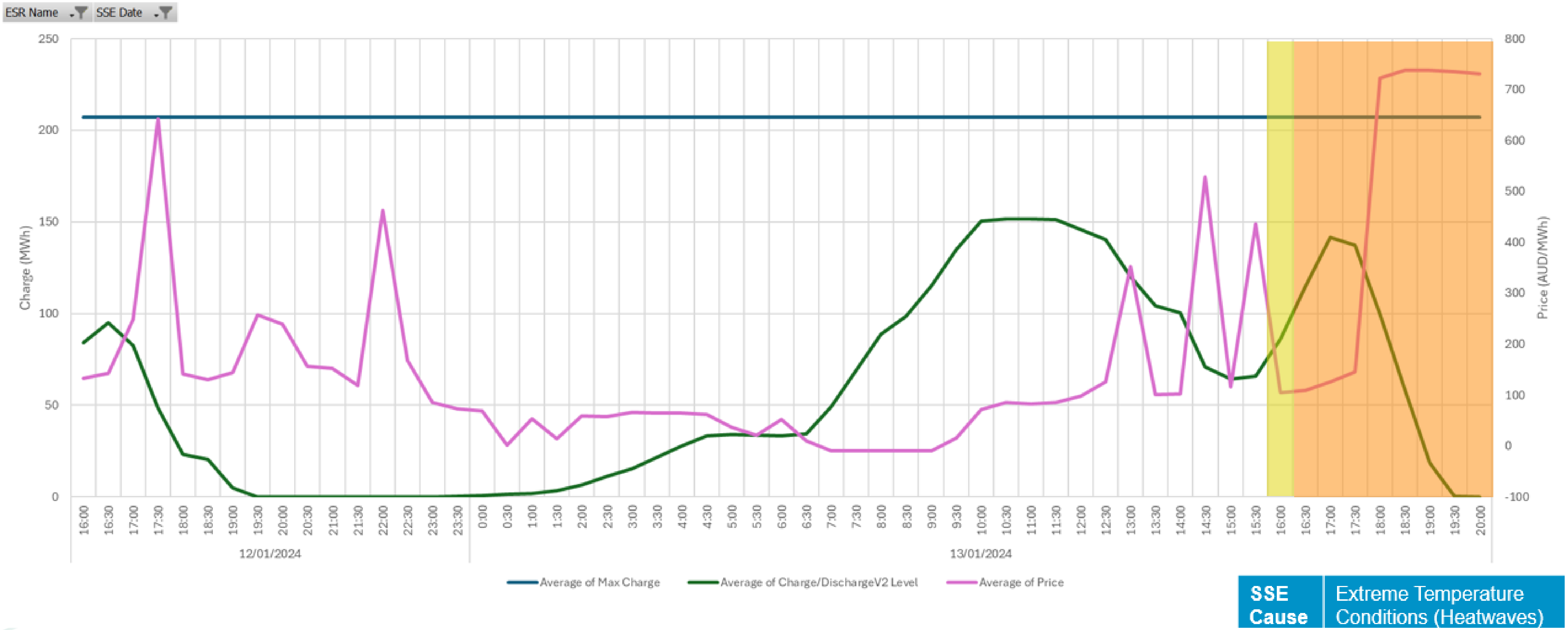


Figure D9: ESR charge levels vs. WEM Energy Price for SSE #2 on 10/12/2024

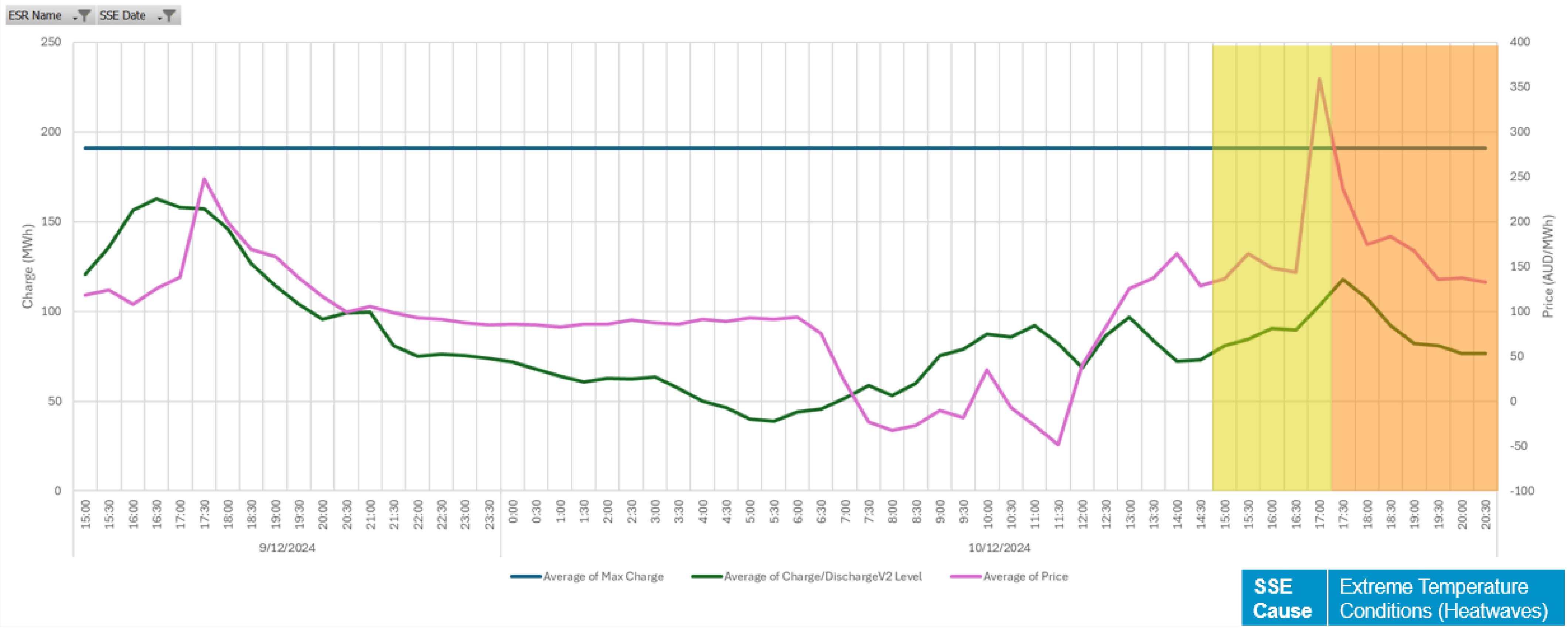


Figure D10: ESR charge levels vs. WEM Energy Price for SSE #3 on 23/01/2025

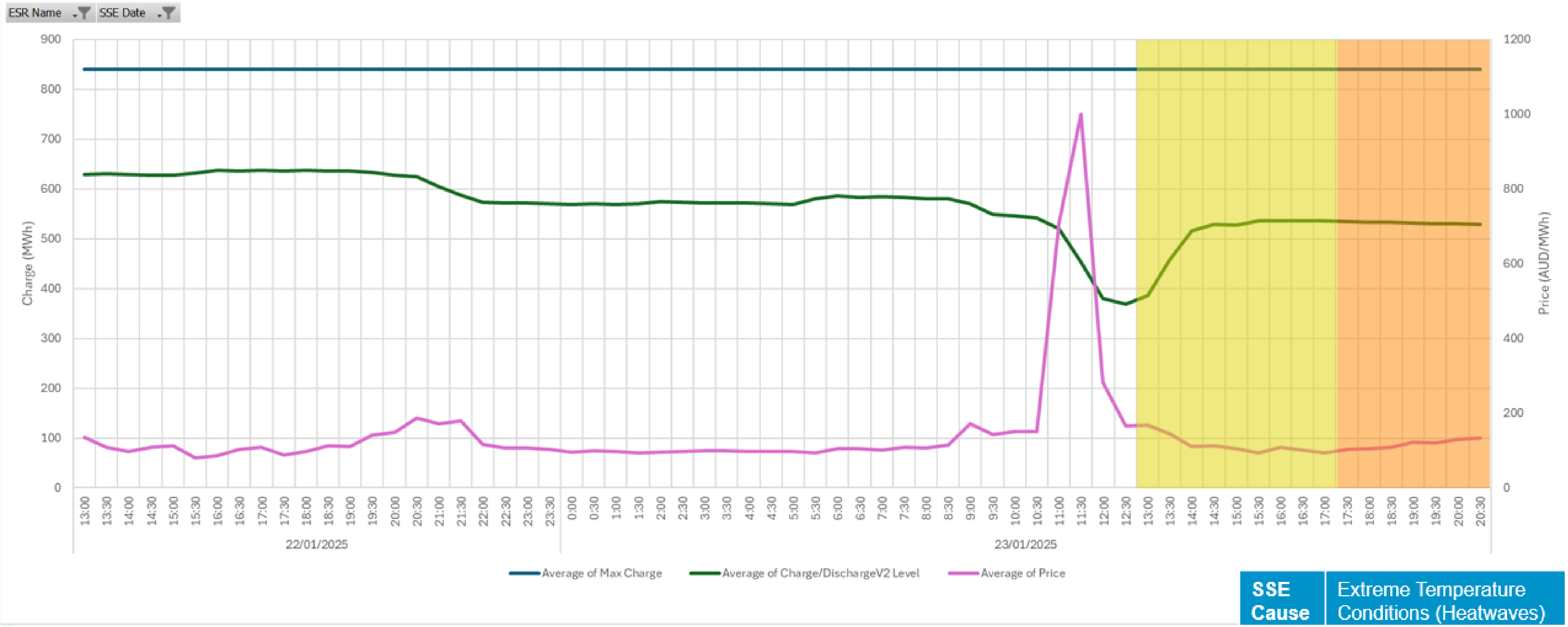


Figure D11: ESR charge levels vs. WEM Energy Price for SSE #4 on 25/08/2025

SSE Cause	Unusually cold, overcast and wet conditions

Figure D12: ESR charge levels vs. WEM Energy Price for SSE #5 on 11/12/2024

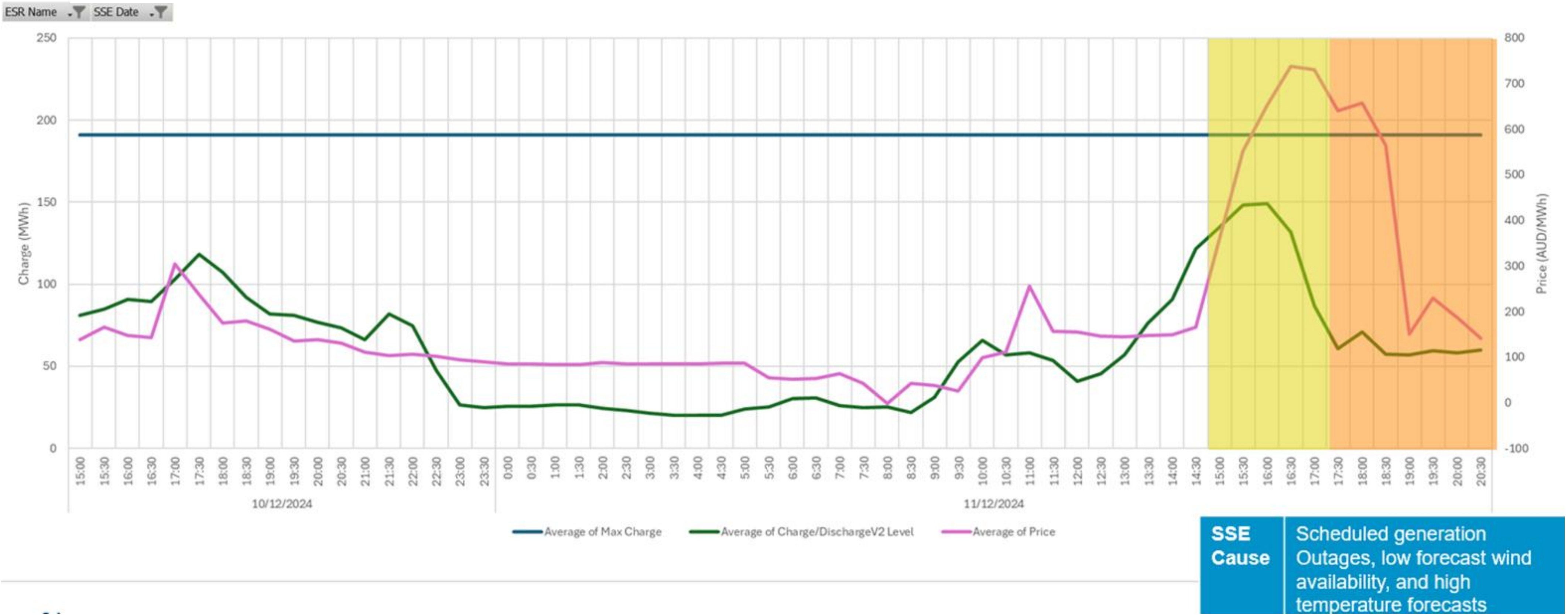


Figure D8 to Figure D12 indicate a potential relationship between high WEM Energy Prices earlier in the day and low ESR charge levels at the commencement of ESROIs. Across all five SSEs, ESRs were observed to discharge during periods of higher energy prices and commence charging as prices declined. This behaviour may result in ESRs not being sufficiently charged by the time their ESROIs commence.

The estimated energy revenue earned from discharging during periods of high energy prices was compared with the refund exposure of the relevant ESRs (KWINANA_ESR1 and COLLIE_ESR1) on the relevant SSE days.[34] Data available to the Coordinator indicate that, in each instance, the estimated energy revenue exceeded the corresponding refund amount for the ESR.

D.2 Future state analysis

AEMO has conducted modelling to forecast the conditions under which ESR dispatch may be required over the next nine years. The AEMO model:

- considers five reference years of half hourly demand profiles and intermittent generation availability;
- models 20 outage scenarios to assess their impact on unserved energy;
- allows ESRs to be dispatched up to their Capacity Credits, with perfect foresight, to optimally avoid unserved energy (i.e., ESROIs are not considered); and
- places ESRs at the top of the merit order (but behind DSP) to ensure that they operate only during events that would otherwise result in unserved energy.

The modelled behaviour of ESRs has been analysed to better understand the conditions under which ESR dispatch is required.

Figure D13 illustrates the structure of the modelling framework, showing how inputs are processed through a reliability model to produce outputs. On the input side, the model uses demand forecasts, intermittent generation time series, facility assumptions, reserve requirements, historical data, outage data, and other modelling assumptions and constraints.

These inputs are processed by the reliability model to produce facility-level outputs (dispatch, outages, and reserve provision) and system-level outputs (Expected Unserved Energy), all at 30-minute intervals. The outputs are then aggregated into the formats required for analysis and reporting.

[34] Estimate Revenue from energy was calculated by multiplying energy sent-out (MWh) by WEM energy price ($AUD) for each dispatch interval on the same SSE day in which the ESRs were discharging. Refund values were provided by AEMO.

Figure D13: Structure of Inputs and Outputs of AEMO mode

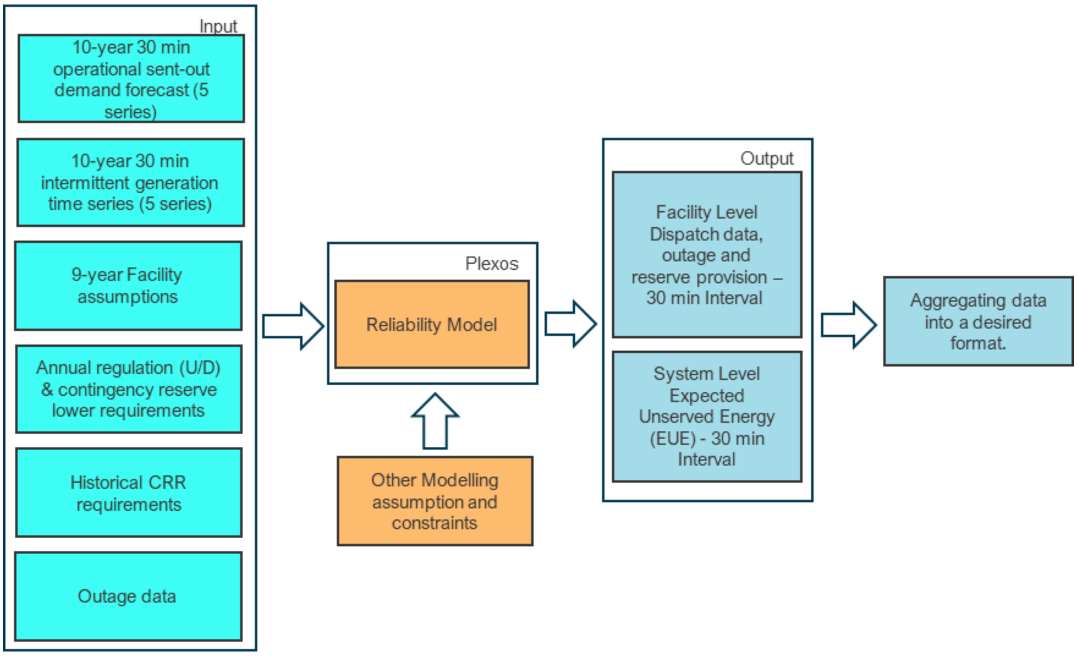
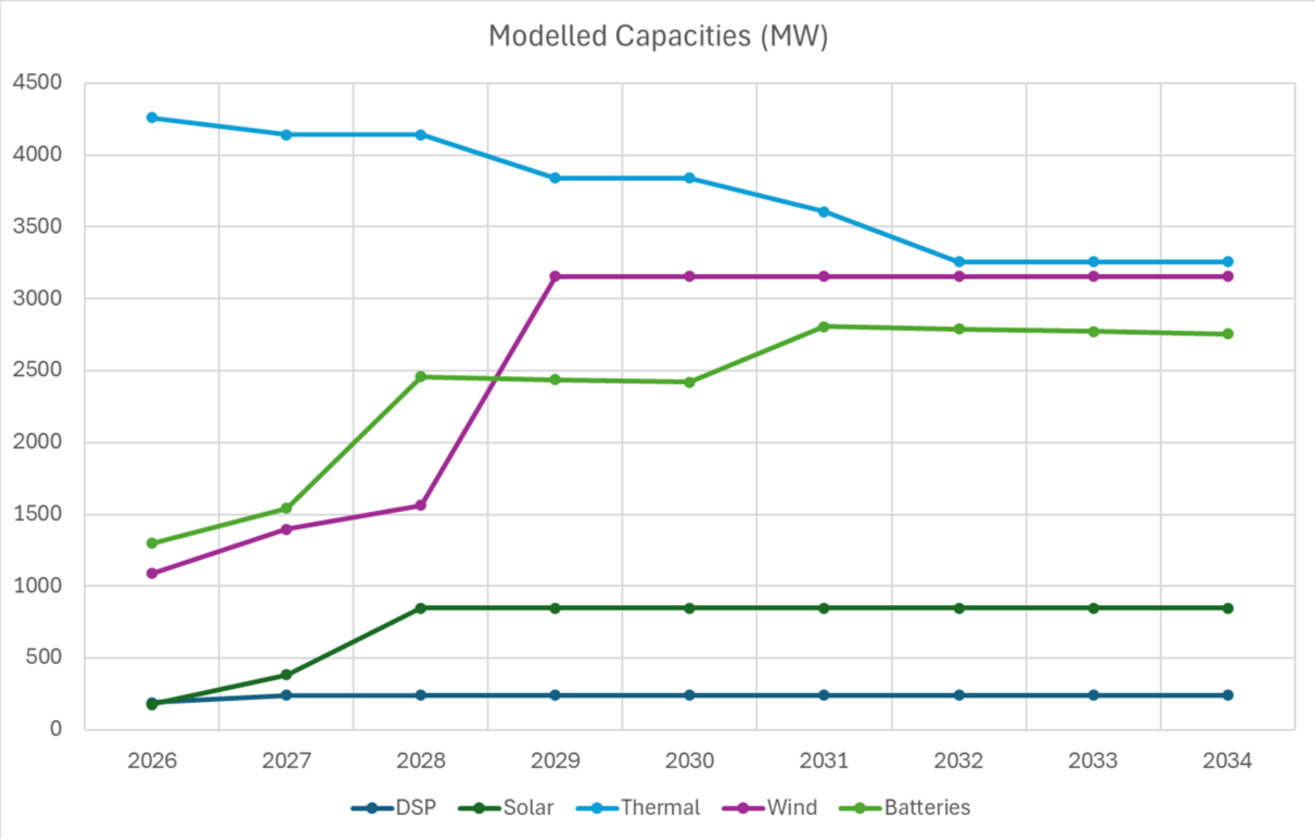


Figure D14 illustrates the capacity assumptions used in the model for the period from 2026 to 2034. The assumptions show a clear transition in the generation mix, with thermal capacity steadily declining, while wind capacity increases sharply to around 3,100 MW by 2029 before remaining relatively flat thereafter. Solar and battery capacities grow rapidly until 2028, with solar capacity stabilising in subsequent years and battery capacity increasing again in 2031 before stabilising. Demand-side participation capacity remains low and relatively constant throughout the modelling period.

Overall, the assumptions reflect a shift away from thermal generation towards greater reliance on wind, solar, and battery storage, with most new capacity added before 2030.

Figure D14: Capacity assumptions



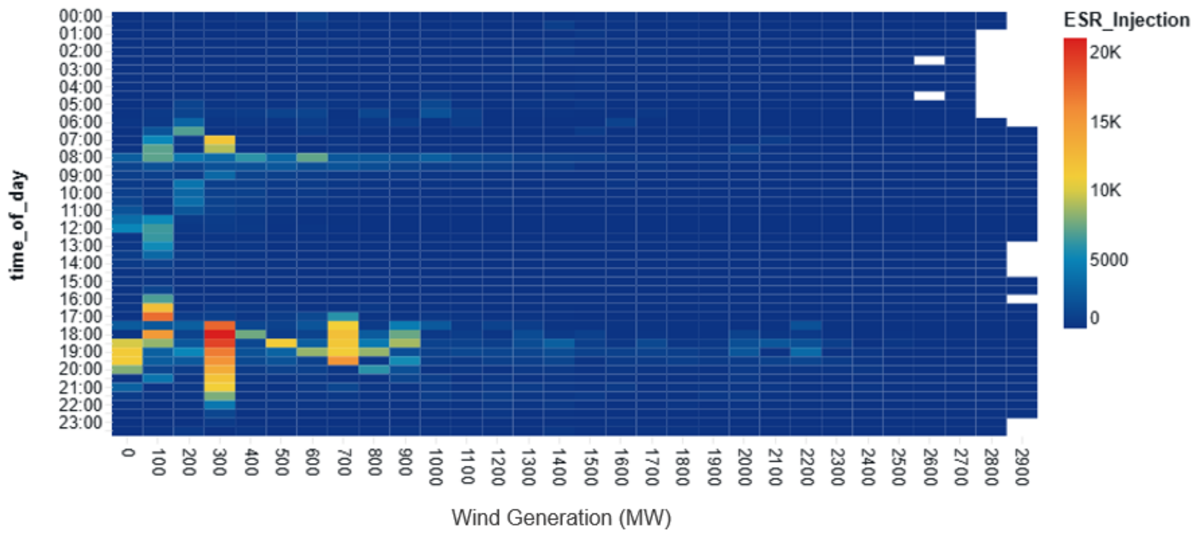
ESR injection requirements by month and time of day are presented in the main body of this report and illustrated in Figure 5, Figure 6 and Figure 7.

- Figure 5 presents the forecast average ESR dispatch by month and Trading Interval for Capacity Year 2026–27;
- Figure 6 presents the results for Capacity Year 2028–29; and
- Figure 7 presents the results for Capacity Year 2030–31.

The future-state analysis indicates that ESRs are predominantly required during summer evening periods, reflecting times of higher demand and increased system stress. While summer evenings remain the primary driver of ESR dispatch requirements, the results also suggest that winter evening periods will become increasingly important from 2028 onwards.

The relationship between ESR injection and wind generation was also analysed. As an example, Figure D15 presents a heat map in which the time of day is shown on the y-axis and wind generation (MW) is shown on the x-axis. The shaded cells indicate the average ESR dispatch (MW) for a given month, time of day, and level of wind generation.

Figure D15: Forecast average ESR dispatch vs. Wind Generation by time of the day for Capacity Year 2030-31



White patches indicate that the model did not produce any outputs for the corresponding combination of time of day and wind generation level.

The analysis shows that the need for ESR support is concentrated during periods of low wind generation, indicating a clear relationship between reduced wind availability and increased system stress. This finding suggests that ESR state-of-charge requirements could potentially be made conditional on low wind generation forecasts, provided that forecast accuracy is sufficiently reliable.

The relationship between ESR injection and solar generation was also examined. However, this relationship was found to be weaker and less consistent than that observed for wind generation, making solar output a less reliable indicator of the need for ESR support.

In summary, the future-state analysis concluded that the timing of ESR support requirements varies by season and is expected to change significantly as the system transitions to higher levels of intermittent generation. Consequently, ESROI periods will need to adapt accordingly.

The analysis also indicates that ESR requirements are closely linked to periods of low wind generation, suggesting that state-of-charge requirements will likely follow wind generation patterns, subject to sufficient forecast reliability.

Appendix E. Evaluation of Demand Side Programme availability obligations

E.1 Evaluation criteria

Demand Side Programme (DSP) availability obligation options were assessed against the following criteria mapped to the State Electricity Objective (SEO).

Table E1: Evaluation criteria used to assess DSP availability options

Criteria	Map to SEO
Availability obligations are aligned with power system needs.	Failing to make Electric Storage Resource/Demand Side Programmes (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 Behind the meter (BTM) storage.	Aligning DSP obligations to enable BTM storage 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.

E.2 Options evaluated

The DSP availability options evaluated are summarised in the tables below.

Table E2: DSP availability options assessed against the SEO

Option	Description
Option 1: Split availability window (Tranche 8).	DSPs must be available as follows: • Available between 6:00 am to 10:00 am and available to curtail up to 4 hours. • Available between 2:00 pm to 10:00 pm and available to curtail up to 8 hours. • DSPs have a four-hour block to charge/restart (10:00am to 2:00 pm).
Option 2: Split availability window (derated version).	The availability windows are as follows: • Available between 8:00 am to 12:00 pm and available to curtail up to 4 hours. • Available between 2:00 pm to 10:00 pm and available to curtail up to 8 hours. • DSPs have a two-hour block to charge/restart (12:00 pm to 2:00 pm). Market Participants can choose to participate in both obligation windows or only the evening (2pm to 10pm) obligation window. Participants choosing the evening window only receive a derated Reserve Capacity Price.
Option 3: Include DSPs in ESROD calculation.	DSPs rolled into Electric Storage Resource Obligation Duration (ESROD) calculation: • AEMO calculates availability requirement based on which intervals have insufficient non-Capability Class 2 (CC2) capacity to meet demand; • No grandfathering for DSPs; • DSPs must meet Peak DSP Dispatch Requirement.
Option 4: DSP availability intervals based on Peak DSP dispatch requirement.	DSP availability intervals determined annually by comparing the reference demand profile developed for Capability Class 3 (CC3) Effective Load Carrying Capability (ELCC) calculations to the 50% Probability of Exceedance (POE) or median growth load profile and identifying which Trading Intervals (or periods of time) DSPs should be available for.

E.3 Evaluation results

E.3.1 Option 1: Split availability window (Tranche 8)

Table E3: Evaluation of Option 1 against the SEO

Criteria	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: • The current 8:00 am to 8:00 pm window does not capture late evening events and fails to recognise that additional capacity is unnecessary during the middle of the day. • Morning window covers early morning hours (6:00 am to 8:00 am) when rooftop solar output is low. • Technical analysis indicates SSEs could occur during later morning hours with one historical event commencing at 11:25 am. *Criteria met fully.*
Availability obligations provide value for money.	DSPs selecting the 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 8:00 pm, thereby reducing the likelihood of costlier Supplementary Capacity (SC) or Non-Co-optimised Essential System Service (NCESS) procurement. *Criteria met fully.*
Availability obligations enable value to be extracted from BTM storage.	Option enables BTM storage to charge in the middle of the day during peak solar output, thereby using renewable energy instead of curtailing it. However, meeting the morning window may be challenging for residential aggregations, as their BTM storage will likely be depleted overnight. This option may also deter large loads with restart limitations from participating as the split window may not enable them to resume operations normally during 10:00 am to 2:00 pm break. To comply with both windows, such loads would need to ensure availability between 6:00 am to 10:00 pm. *Criteria met substantially.*
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.	This change is moderately simple (relative to the other options) to implement and will only require minor rule, process and system changes. However, the morning window spans two Trading Days.

Criteria	Evaluation
	Australian Energy Market Operator (AEMO) has advised this will add to implementation complexity and cost. *Criteria met partially.*
Overall Performance.	Most criteria met substantially. 

E.3.2 Option 2: Split availability window (derated version)

Table E4: Evaluation of Option 2 against the SEO

Criteria	Evaluation
Availability obligations aligned with power system needs.	This option performs slightly less well than Option 1 as the morning availability window does not include 6:00 am to 8:00 am. This morning window is more likely to encounter capacity shortages as rooftop solar output is low (particularly in winter) and demand is high due to the South West Interconnected System (SWIS) load shape. However, we note that no DSP dispatch events or system stress events have historically occurred during this period. *Criteria met substantially.*
Availability obligations provide value for money.	DSPs opting for reduced availability by participating only in the second window receive a derated Reserve Capacity Price. Hence, no customer value is diluted. *Criteria met fully.*
Availability obligations enable value to be extracted from BTM storage.	Even though the charging window for BTM storage under this option is reduced (from 10:00 am to 2:00 pm to 12:00 pm to 2:00 pm), DSPs should still be able to charge BTM storage in their portfolio during peak solar hours. Those with load restart limitations can participate in the evening window. *Criteria met fully.*
Approach is flexible enough to change as power system needs evolve and change.	This option performs slightly less well than Option 1 on this criteria as it does not have the flexibility to include early morning intervals if in the future availability during early winter mornings becomes important. *Criteria met partially.*
Approach is transparent and predictable.	See Option 1. *Criteria met fully.*
Cost and complexity of implementation is reasonable	This option will be simpler to implement than Option 1 due the 6:00 am to 8:00 am Trading Intervals from the previous Trading Day being excluded. *Criteria met fully.*

Criteria	Evaluation
Overall Performance.	Most criteria met substantially.

E.3.3 Option 3: Include DSPs in ESROD calculation

Table E5: Evaluation of Option 4 against the SEO

Criteria	Evaluation
Availability obligations aligned with power system needs.	Approach identifies Trading Intervals where non-CC2 capacity is insufficient to meet demand during the evening peak demand period. This means that evening reliability needs are well met under this approach. However, given ESROIs cover late afternoon to evening, DSPs will not be available for winter morning peaks. The technical analysis indicates DSP dispatch during the morning is possible but likely to be uncommon. *Criteria met substantially.*
Availability obligations provide value for money.	ESRs & DSPs will get same duration requirement under this approach. This is likely to be less than the current 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. DSPs will be available after 8:00 pm thereby reducing the likelihood of costlier SC procurement. *Criteria met partially.*
Availability obligations enable value to be extracted from BTM storage.	See Option 1. ESROD starts after peak solar hours enabling BTM storage to charge. *Criteria met fully.*
Approach is flexible enough to change as power system needs evolve and change.	Availability obligations under this approach will 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.*

Criteria	Evaluation
Overall Performance.	Some criteria met substantially or most met partially. ◐

E.3.4 Option 4: DSP availability intervals based on Peak DSP dispatch requirement

Table E6: Evaluation of Option 4 against the SEO

Criteria	Evaluation
Availability obligations aligned with power system needs.	This approach assumes that DSPs will only be needed at times when demand is likely to exceed the 50% POE peak forecast (vs modelling ability of CC2 & non-CC2 capacity to meet peak demand). This may not be true, as DSP and ESR need is driven by the level of non-CC2 capacity available. It is unclear whether DSPs would be required to be available after 8:00 pm 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. *Criteria not met.*
Availability obligations enable value to be extracted from BTM storage.	Demand during peak solar hours is unlikely to be greater than the 50% POE peak. As such, DSP availability requirements during peak solar hours are unlikely to manifest under this approach. *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 substantially or most met partially. ◐