Government of Western Australia
Department of Mines, Industry Regulation and Safety
Energy Policy WA

Reserve Capacity Mechanism Review

Information Paper (Stage 1) and Consultation Paper (Stage 2)

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Working together for a brighter energy future.

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Abbreviations

Term	Definition
AEC	Australian Energy Council
AEMO	Australian Energy Market Operator
BRCP	Benchmark Reserve Capacity Price
CARWG	Cost Allocation Review Working Group
CDA	Consumption Deviation Application
CCGT	Combined Cycle Gas Turbine
CONE	Cost of New Entry
CRC	Certified Reserve Capacity
CT	Combustion Turbine
DER	Distributed Energy Resource
DPV	distributed photovoltaic
DSM	Demand Side Management
DSP	Demand Side Programme
ECP	Expert Consumer Panel
EFORd	Equivalent Forced Outage Rate on Demand
ELCC	Effective Load Carrying Capability
EPWA	Energy Policy WA
ERA	Economic Regulation Authority
ESOO	Electricity Statement of Opportunities
ESR	Electric Storage Resource
ESS	Essential System Services
EUE	Expected Unserved Energy
FCESS	Frequency Co-Optimised Essential System Services
ICAP	Installed Capacity

Term	Definition
IRCR	Individual Reserve Capacity Requirement
LSG	Load for Scheduled Generation
MAC	Market Advisory Committee
NAQ	Network Access Quantity
NEM	National Electricity Market
NTDL	Non-Temperature Dependent Load
OCGT	Open Cycle Gas Turbine
POE	Probability of Exceedance
RCM	Reserve Capacity Mechanism
RCMRWG	RCM Review Working Group
RCOQ	Reserve Capacity Obligation Quantity
RCP	Reserve Capacity Price
RCR	Reserve Capacity Requirement
RLM	Relevant Level Methodology
RoCoF	Rate of Change of Frequency Control
RTM	Real-Time Market
SRMC	Short-Run Marginal Cost
SOG	Sent Out Generation
SRC	Supplementary Reserve Capacity
SWIS	South West Interconnected System
SWISDA	SWIS Demand Assessment
TDL	Temperature Dependent Load
TOU	Time of Use
UCAP	Unforced Capacity
VCR	Value of Customer Reliability

Term	Definition
VoLL	Value of Lost Load
VPP	Virtual Power Plant
WACC	Weighted Average Cost of Capital
WEM	Wholesale Electricity Market

Executive Summary

The Reserve Capacity Mechanism Review

The Coordinator of Energy (Coordinator), in consultation with the Market Advisory Committee (MAC), is reviewing the Reserve Capacity Mechanism (RCM) under clause 2.2D.1 of the Wholesale Electricity Market (WEM) Rules. The RCM Review also incorporates the Coordinator's first review of the Planning Criterion under clause 4.5.15 of the WEM Rules.

The RCM Review is being conducted in three stages:

- Stage one focussed on the definition of reliability and the characteristics of the capacity needed in future years, with this stage including the Planning Criterion, the RCM products, the methods for assigning Certified Reserve Capacity (CRC) and the Benchmark Reserve Capacity Price (BRCP). [1]
- Stage two assessed how the outcomes of stage one affect the operation of other parts of the RCM, including the Individual Reserve Capacity Requirements (IRCR), Demand Side Programmes (DSPs), outage scheduling and the refunds mechanism.
- Stage three will deliver detailed design in the form of proposed rule amendments.

In July 2022, the Minister for Energy directed EPWA to investigate policy options for penalty regimes for high emission technologies. While not part of the original scope for the RCM Review, EPWA has developed and analysed policy options in conjunction with the RCM Review. Consultation on the implementation of this policy will be conducted separately in due course.

The MAC constituted the RCM Review Working Group (RCMRWG) to support the RCM Review. More information on the RCM Review is available from the Energy Policy WA (EPWA) website,[2] including the Scope of Works for the review, the Terms of Reference for the RCMRWG, papers for RCMRWG and MAC meetings and detailed minutes for each meeting.

Call for Submissions

This paper is of two Parts:

- Part 1 is an Information Paper that presents the final design for elements of the RCM investigated and developed in stage one of the RCM Review including:
  - the Planning Criterion;
  - the new Flexible Capacity product;
  - the BRCP; and
  - methodologies for assigning CRC to the different capacity products and Capability Classes.

[1] Alternative methods to assign CRC to intermittent generators were identified in stage one of the review and were assessed in stage two.

[2] https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group

- Part 2 is a Consultation Paper that sets out the findings and recommendations arising from stage two of the RCM Review, presenting proposals for changes to the design of:
  - IRCR;
  - CRC allocation and dispatch for DSPs;
  - testing, outages and refunds; and
  - two new proposals on elements of stage one (unserved energy target in the Planning Criterion and the party responsible for setting the BRCP reference technologies).

Stakeholder feedback is invited on the proposed changes to the RCM that are outlined in Part 2 of this paper. Submissions can be emailed to energymarkets@dmirs.wa.gov.au. Any submissions received will be published on www.energy.wa.gov.au, unless requested otherwise. The consultation period closes at **5:00pm WST on Wednesday 31 May 2023**. Late submissions may not be considered.

Design Proposals and Rationale

The SWIS is undergoing a major transition, with the nature of the demand profile and electricity supply sources rapidly changing. In this transition to a low emissions energy system, characterised by increasing levels of intermittent and distributed generation, new market design elements are needed to ensure secure and reliable electricity supply. While, in some cases, these new elements bring an increased cost, analysis suggests that they are necessary to avoid significant and ongoing reductions in the reliability of electricity supply for consumers.

The remainder of this section lists the Review Outcomes (Table 1) and Proposals (Table 2) and provides a summary of the rationale for each outcome and proposal.

Table 1: Stage 1 Review Outcomes

Review Outcome	Rationale
The Planning Criteria	
Review Outcome 1 The existing limbs of the Planning Criterion will be retained. The reserve margin was amended to refer to the largest contingency on the power system, rather than the largest generating unit by amending clause 4.5.9(a)ii. This change commenced on 1 January 2023 as part of the *Wholesale Electricity Market Amendment (Tranche 6 Amendments) Rules 2022*. The reserve margin will be further amended by changing sub-clause 4.5.9(a)i to use the (AEMO determined) proportion of the generation fleet expected to be unavailable at system peak due to forced outages, rather than a hardcoded	The existing Planning Criterion has two limbs: • a forecast peak limb, requiring sufficient capacity to meet the forecast 10% probability of exceedance (POE) peak load, plus additional amounts to manage outages, frequency keeping and Intermittent Loads; and • an EUE limb, requiring sufficient capacity to limit EUE to 0.002% of expected demand. The Stage 1 Paper proposed to retain the existing limbs with changes to the first limb of the Planning Criterion. Some of these changes have already been implemented.

Review Outcome	Rationale
percentage. Amending Rules will be drafted and consulted on in stage 3 of the RCM Review. Following further consideration of the target Expected Unserved Energy (EUE) percentage, EPWA has included a new proposal to reduce the EUE percentage in the Stage 2 Consultation Paper.	Submissions supported retaining both limbs of the existing Planning Criterion. EPWA has further considered the target EUE percentage and has included a new proposal in Part 2 of this paper (see section 5.4).
The Reserve Capacity Products	
Review Outcome 2 Retain the existing 'Peak capacity' product to provide an explicit price signal several years ahead of the need for new capacity to meet peak demand and overall energy supply.	Submissions on the Stage 1 Paper supported retaining the peak capacity product.
Review Outcome 3 A new flexible capacity product will be introduced to the RCM. The Planning Criterion will include a third limb requiring AEMO to procure flexible capacity to meet the size of the steepest operational ramp expected on any day in the upcoming Capacity Year from either the 10% or 50% POE load forecasts.	Submissions supported the introduction of a flexible capacity product. All submissions supported the inclusion of a new Planning Criterion limb for flexible capacity.
Review Outcome 4 The RCM will not include a specific product to address intermittent output volatility at this time. The RCM Planning Criterion will not include provisions for intermittent output volatility at this time. Facilities holding flexible capacity credits will be required to accredit for all types of Frequency Co-optimised Essential System Services (FCESS) that they are capable of providing, but will not be obligated to offer into the FCESS markets.	Most submissions agreed, but several noted that their view could change depending on how the Essential System Services (ESS) markets develop and whether the new flexible capacity product encourages commissioning of enough ESS-capable facilities. One respondent noted a desire for the costs of volatility to be paid by those causing the volatility. ESS cost allocation is considered as part of EPWA's Cost Allocation Review. Facilities holding flexible capacity credits are likely to be able to, and to want to, provide some or all of the FCESS flexible capacity. They could be required to make their flexible capacity available in the relevant FCESS markets, like facilities holding Supplementary ESS Mechanism Awards. EPWA considers that, while availability obligations and refunds for flexible capacity

Review Outcome	Rationale
	providers should relate only to the provision of energy, it is reasonable to require them to accredit for the FCESS that they are capable of providing.
Review Outcome 5 The RCM will not include a specific product to manage minimum demand at this time.	Most submissions supported using mechanisms outside the RCM to manage minimum demand. One respondent considered that the RCM should include a product to encourage increased demand during low-load periods, and another respondent considered that EPWA's ongoing distributed energy resources (DER) work and the SWIS Demand Assessment (SWISDA) may identify potential for the RCM to contribute to managing low-load periods. AEMO's ongoing procurement of Non Co-optimised Essential System Services (NCESS) for minimum demand services highlights that minimum demand remains an ongoing concern. EPWA will again consider the need for a dedicated minimum demand service as part of its Demand Side Response Review.
The Benchmark Reserve Capacity Price	
Review Outcome 6 The Reserve Capacity Price for the peak capacity and flexible capacity products will be constructed using the same elements, though with different BRCPs and capacity targets. The Reserve Capacity Price paid to a facility providing flexible capacity will never be lower than the peak Reserve Capacity Price. Proposed facilities will have the option to seek a fixed price for flexible capacity on the same basis as is available for peak capacity.	Respondents supported using the same price curves for both the peak and flexible capacity products, ensuring that facilities never receive a lower price for providing flexible capacity than for providing peak capacity, and a fixed price option for facilities providing flexible capacity. Respondents raised a number of points about RCM pricing, including that: • the current five-year fixed price horizon for peak capacity is too short, and should be extended to 10 or 15 years; • volatility in the current RCP will not support long-term investment in flexible generation and storage facilities; and • EPWA should consider amendments to the current price cap and floor regime, and the price curve more generally, to

Review Outcome	Rationale
	ensure appropriate signals for participation. While these items are outside the scope of the current RCM Review, they have been noted, and EPWA is considering them separately.
Review Outcome 7 Further consideration was required on the approach to setting the reference technology for the BRCP. EPWA has included a new proposal in the Stage 2 Consultation Paper. The BRCP will be set based on a facility located in an uncongested part of the network. If there is no uncongested part of the network, the BRCP will be set based on a facility located where there is limited congestion. The guidance in the WEM Rules will set out the principles and process steps to determine parameter values instead of recording fixed parameter values, especially where those parameters are likely to change markedly from year-to-year. The WEM Rules will not specify the use of gross or net cost of new entry (CONE), but will specify that any move away from gross CONE must be accompanied by analysis and consultation.	All submissions supported the Economic Regulation Authority (ERA) setting the BRCP methodology according to principles set out in the WEM Rules. One participant noted a desire for the BRCP methodology to balance investment certainty with the need for flexibility, citing an example of the Weighted Average Cost of Capital (WACC) value being inappropriately hardcoded in the WEM Procedure. EPWA has further considered the approach to setting the reference technology for the BRCP and has included a new proposal in Part 2 of this paper (see section 5.5). Respondents supported retaining a gross CONE approach. One respondent requested that the reference facility location instead be in 'any suitable uncongested part of the network', to avoid unnecessary analysis to determine which location was the least congested.
Capacity Certification	
Review Outcome 8 The current Availability Classes will be replaced with new Capability Classes: • Class 1: Unrestricted firm capacity; • Class 2: Restricted firm capacity; and • Class 3: Non-firm capacity. Hybrid facilities will be assessed as a single entity. Facilities holding Capacity Credits in Capability Classes 1 and 2 will continue to have obligations to offer into the STEM and Real-Time Markets, undergo capacity testing, and pay refunds when not meeting their obligations.	Most submissions supported the new Capability Classes and the amendment of CRC allocation methodologies to consider a hybrid facility as a single entity. Submissions did not support retaining a 14-hour fuel requirement. The 14-hour fuel requirement stems from AEMO's implementation of the current Availability Class definitions in clause 4.11.4. The related WEM Procedure requires participants to demonstrate firm fuel availability for peak Trading Intervals (8am-10pm) on all Business Days. This procedure was reviewed and updated in

Review Outcome 9 Capability Class 1 facilities will be required to be available during all Dispatch Intervals, unless on an outage, and the requirement to demonstrate sufficient fuel for 14 hours of daily operation will be retained. Capability Class 1 capacity will be assigned CRC based on its expected maximum output at 41 degrees.	December 2022, and the requirement was reconfirmed. EPWA has considered the submissions and remains concerned that relaxing the requirement to show evidence that generation facilities have sufficient fuel to operate during periods of system stress would risk reducing the level of reliability provided for by the WEM Rules, and that doing so would be counter to one of the key principles of the RCM Review. Recent fuel supply issues illustrate the importance of fuel availability, and recent changes made as part of the Market Power Mitigation Strategy mean that participants now have certainty that the costs of long-term take-or-pay fuel contracts can be reflected in market submissions. The fundamental reason for having three Capability Classes is to recognise that facilities with firm availability provide a greater contribution to system reliability than those with lower availability. Participants who wish to procure shorter duration fuel contracts can instead seek certification in Capability Class 2 and receive a pro-rated CRC accordingly, with fuel availability obligations in fewer hours than are faced by facilities in Capability Class 1. This will enable the participants to reduce their fuel contract costs. However, EPWA acknowledges that the current WEM Procedure may be more restrictive than is warranted to ensure fuel availability during times of system stress. The current WEM Procedure requires demonstrating fuel availability during the midday trough, when it is increasingly likely that the majority of the facilities will be dispatched down or off. In the future, it will be more appropriate for the WEM Procedure to focus on the availability gap – the period over and after the peak demand– rather than periods in the middle of the day. EPWA considers that the WEM Rules could provide additional guidance on the implementation of the provisions in

Review Outcome	Rationale
	clause 4.11.4(a)ii such that AEMO should consider the time of day in which certification in Capability Class 1 requires firm fuel contracts, particularly as the overnight duration gap extends (see section 2.4.2). Offer obligations, testing requirements, and refund incentives will remain in place.
Review Outcome 10 The availability duration requirement for new Capability Class 2 facilities that are not DSPs and do not consist solely of Electric Storage Resource (ESR) components will be 14 hours, to match the Capability Class 1 fuel availability requirement. Capability Class 2 capacity will be assigned CRC based on its expected maximum output at 41 degrees, pro-rated by the number of hours it can sustain this output divided by the 14-hour availability duration requirement. Capability Class 2 facilities which consist solely of ESR components will continue to be assessed based on the linear derating method, which may have a different number of hours required. Proponents can request a five-year fixed availability duration requirement for an ESR facility. DSPs will continue to be assessed based on a 12-hour availability requirement. AEMO will forecast the availability duration gap based on the capacity of the existing and committed fleet, and will publish it in the Electricity Statement of Opportunities (ESOO), including forecasts for subsequent years. The WEM Rules will set metrics to identify if the duration gap is at risk of not being met in future years and require AEMO to monitor and publish these metrics. The Coordinator's reviews in WEM Rule 4.13B will include consideration of: • availability duration gap metrics; • availability duration requirements for ESR and DSP facilities.	In the Stage 1 Consultation Paper, EPWA proposed to use an availability duration target to set the CRC for Capability Class 2 facilities. Under this approach, the duration gap is assumed to be met by either generation (primarily overnight wind in later years) or by increasing storage volumes to allow a longer discharge period. Submissions raised alternative options for Capability Class 2 certification. These are discussed in section 2.4.2. EPWA considers that the relevant duration requirement used in prorating the capacity of Capability Class 2 facilities should match the Capability Class 1 requirement. The existing method for Capability Class 2 facilities consisting solely of ESR components will remain unchanged as per the scope of the RCM Review. In the submissions, stakeholders also considered that it would be important for the ERA's BRCP methodology to align with AEMO's availability duration calculations. Respondents considered that a five-year fixed duration would not align with the expected life of facilities providing flexible capacity, which are expected to have at least a 10-year investment life. EPWA acknowledges the concern over a mismatch between the time/technical parameters that affect revenue and the expected life of an investment, particularly in relation to longer duration storage facilities. EPWA is examining this issue separately.

Review Outcome	Rationale
Review Outcome 11 The fleet CRC is to be set as follows: (1) Take historical load for the most recent 5 Capacity Years, and adjust it to account for: (a) output profiles of current levels of DER; and (b) DSP dispatch, unserved energy and use of Supplementary Reserve Capacity (SRC) and NCESS. (2) Take historical generation output for each Capability Class 3 facility for the same period, and adjust it to remove the effects of any involuntary curtailment (whether this is economic curtailment by the clearing engine, network constraints, or AEMO direction). (3) Remove data from the Capacity Year with the lowest peak demand. (4) For the whole remaining dataset, and for each individual year in the remaining dataset, calculate the initial Fleet effective load carrying capability (ELCC) as follows: (a) increase or decrease demand by adding or subtracting the same MWh quantity in each interval to the point at which expected EUE is at the level specified in the Planning Criterion, assuming that: (i) Capability Class 1 and 2 facilities have no planned outages; (ii) Capability Class 1 and 2 facilities suffer forced outages at historic rates; (iii) there are no network constraints; (b) remove all Capability Class 3 facilities from the generation fleet; (c) reduce load until the EUE is the same MWh quantity as it was in step (4)(a); and (d) set the fleet ELCC to the quantity of load reduced in each interval, converted to MW. (5) Set the fleet CRC as the lower of: (a) the fleet ELCC for the whole dataset; and (b) the average of the fleet ELCCs for each individual year.	Respondents were supportive of amending the current Relevant Level Method for CRC allocation to intermittent generators, but differed in their views on a suitable replacement. Alternative methods for allocating CRC to Capability Class 3 facilities were further explored and consulted on during Stage 2 of the review. The Stage 1 Consultation Paper identified two methods that used ELCC to set the total CRC to be allocated to the intermittent fleet, and one that assessed each facility individually, without considering the overall contribution of the fleet. Submissions and subsequent discussions at the RCMRWG and the MAC concluded that an approach which considered the overall fleet contribution was appropriate, and EPWA did not consider the individual facility assessment approach any further. Respondents also noted a desire to mitigate year-to-year volatility in CRC outcomes to improve certainty for investors. EPWA remained concerned that any method to reduce CRC volatility should not cause CRC allocations that overstate performance by increasing the weight placed on performance in lower stress periods. As a result, the proposed fleet ELCC process will include measures to reduce year-to-year volatility while maintaining focus on high stress periods. During stage 2 of the review, EPWA carried out additional analysis on four options for CRC allocation to intermittent generators. Analysis for the four methods is captured in RCMRWG papers. Ultimately, EPWA (in consultation with the MAC and the RCMRWG) has determined to use the simpler IRCR method. This makes it easier for participants and investors to apply the method themselves, and aligns incentives for capacity suppliers and consumers. The approach to selecting IRCR intervals was also discussed with the RCMRWG, and

Review Outcome	Rationale
The fleet CRC will be allocated to individual facilities as follows: (1) Take historical output for each Capability Class 3 facility for the previous five Capacity Years, and adjust to remove the effects of any involuntary curtailment (whether due to offer prices, network constraints, or AEMO direction). (2) Remove data from the Capacity Year with the lowest system peak demand. (3) Use the selection method specified in Section 3.2.3 of this document to identify the IRCR intervals for each year of the remaining dataset. (4) For each Capability Class 3 facility: (a) find the mean historical output in the intervals selected in step 3; (b) set the facility proportion equal to the quantity determined for the facility in step (4)(a) divided by the sum over all Capability Class 3 facilities of the quantities determined in step (4)(a). (c) Set the facility CRC equal to the fleet CRC multiplied by the facility proportion determined in step (4)(b). The method for selecting the IRCR intervals is discussed further in Chapter 3 of Part 2.	is presented for consultation in section 3.2 in Part 2.
Review outcome 12 Participants will continue to procure their own expert reports. AEMO will have powers to audit report accuracy: • AEMO will be able to seek independent review of any submitted report and may reject the report if the figures appear to be inflated; and • once a facility is operational, AEMO will compare actual performance with projected performance, and may remove experts from its approved list if their estimates are persistently inaccurate.	EPWA proposed that, to ensure independent estimates of intermittent generator output in historical periods, AEMO should procure expert reports to derive estimates of on behalf of participants. Only one respondent supported the proposal for AEMO to procure independent reports. Other respondents disagreed with the proposal. EPWA acknowledges the complexities in separating this report from the project development and financing process, but considers that additional measures are required to ensure the impartiality of these reports, as overly optimistic expert

Review Outcome	Rationale
	estimates are a risk to power system reliability.
Review Outcome 13 The quantity of flexible CRC allocated to a facility will be capped at: • its CRC for peak capacity; and • the maximum MW quantity that it could reach four hours after being dispatched from a cold start. The WEM Rules will require AEMO to set maximum standards for: • minimum stable loading level; • start time (time from receiving a Dispatch Instruction when in a “cold” state to reaching the facility controllable range); • minimum running time (time from receiving a Dispatch Instruction when in a “cold” state to turn on, run, and turn off again); • stop time (time from receiving a Dispatch Instruction when running at the minimum of its controllable range to ramp down to zero output); and • restart time (time from desynchronising to synchronizing). The minimum stable loading level is particularly important for the effectiveness of this product, and is likely to be 10% of the facility nameplate capacity or less. Facilities providing flexible capacity will be dispatched for energy through the already established dispatch algorithm, and will not be explicitly held in reserve for later use.	During stage 2 of the RCM Review, EPWA considered market elements required to implement a flexible capacity product, particularly capacity certification and facility dispatch. These issues were discussed with, and were generally supported by the RCMRWG, and are included below for information. Flexible capacity requirements will be incorporated into the existing ESOO and certification processes. A facility will not be able to be certified for flexible capacity only, it must also provide peak capacity. Minimum performance requirements for the flexible capacity product will likely change over time as the load shape changes. The WEM Rules will require AEMO to consider, as part of the ESOO processes, the capability required of facilities to meet the identified need, ensuring that providers of the flexible capacity can move quickly from no output (or from full consumption) in the midday to rapidly increase output (or decrease consumption) as the high ramp requirements begin.
Review Outcome 14 CRC allocation will remain on an Installed Capacity (ICAP) basis), and the reserve margin will be set accordingly, excluding facilities which have had their CRC reduced due to a high Equivalent Forced Outage Rate on Demand (EFORd). If over a three-year period a facility has an EFORd higher than 10%, AEMO will be required to reduce its CRC by the EFORd, unless it has evidence that	All submissions supported continuing to allocate CRC on an ICAP basis. Some respondents supported the reduction of CRC for facilities with high EFORd, others disagreed on the basis that CRC allocation should be forward looking rather than backward looking. Others thought it is necessary to allow discretion for outages which would not reasonably be expected to

Review Outcome	Rationale
the underlying reasons for the high outage rate have been resolved.	present a risk to the capacity provider's ability to provide CRC into the future. EPWA agrees that CRC allocation should be based on the expected future ability of a facility to provide capacity, but still considers that it is necessary to strengthen the CRC derating requirements in clause 4.11.1(h). EPWA accepts that a facility's historical outage rate may not represent its expected future outage rate, and will include some discretion for AEMO to not apply the derating if it is satisfied that the underlying reason for the outage has been addressed.

Table 2: Stage 2 Proposals

Stage 2 Proposals
IRCR for Peak Capacity
Proposal A: Continue to set participant IRCR based on contribution to load in high demand intervals. Following further consideration of the target EUE percentage, EPWA has included a new proposal to reduce the EUE percentage in the Stage 2 Consultation Paper.
Proposal B: Retain the current approach of using only intervals in the Hot Season (Trading Days from 1 December to 31 March) to set IRCR. Amend the IRCR interval selection provisions to ensure that: • all 12 highest demand intervals in the Hot Season are selected; • intervals on a minimum of three days are selected; and • where the peak intervals occurring on each day are not contiguous, the intervening intervals are selected. The Coordinator's review of the WEM effectiveness will include reviewing whether extreme demand events are forecast to occur outside the hot season.
Proposal C: Remove Temperature Dependent Load (TDL) / Non-Temperature Dependent Load (NTDL) multipliers from the IRCR process.
Proposal D: Calculate IRCR on a daily basis.

Stage 2 Proposals
Set representative load for new meters based on the maximum of the median demand in the four peak intervals of any prior calendar month.
IRCR for Peak Capacity
Proposal E: Set participant IRCR for flexible capacity based on the load shape in high ramp periods.
Proposal F: Set IRCR for flexible capacity based on the three days with the highest four-hour upwards ramp at any time during the year. Require AEMO to publish the forecast ramp so that consumers can monitor and respond to the cost signal.
DSP CRC
Proposal G: Where a DSP has: • the same Associated Loads that it had in the previous year, assign CRC based on IRCR of the Associated Loads less the minimum load requirement of the Associated Loads; and • different Associated Loads from the previous year, assign CRC based on a value nominated by the Market Participant.
Proposal H: Remove Consumption Deviation Applications (CDAs) from the assessment of DSP CRC.
Proposal I: Allow sites with collocated load and generation or storage to be Associated Loads of a DSP.
Proposal J: Adopt a dynamic baseline to measure DSP dispatch performance against. Continue to assess the detailed dynamic baseline methodology. Consider reducing the number of hours that DSPs can be dispatched.
Testing
Proposal K: Require facilities holding flexible capacity credits to be tested for start, stop, restart, and minimum running times; ramp capability; and minimum stable loading level. Allow facilities to pass flexible capacity tests by observation. Require AEMO to schedule tests of flexible capacity characteristics to coincide with tests for peak capacity.
Proposal L: Adjust Reserve Capacity Testing for DSPs to reflect a shift to a dynamic dispatch baseline.

Stage 2 Proposals
Require AEMO to consider the expected baseline when scheduling DSP tests. Treat a failed test as the beginning of a Forced Outage, rather than a permanent reduction of Capacity Credits.
Outage Planning
Proposal M: Amend the outage planning process so that AEMO considers availability of both peak and flexible capacity when assessing and approving outages.
Proposal N: Require flexible capacity holders to lodge outages relating to capability to provide flexible capacity.
Proposal O: Allow DSP owners to manage their own outage schedules, without participating in the outage planning regime. Adjust DSP availability measurement to use actual demand of the Associated Loads rather than the Relevant Demand.
Refunds
Proposal P: Capacity refunds for both peak capacity and flexible capacity will be paid from a single pool of capacity payments. Capacity refunds for flexible capacity will be capped at a set portion of total capacity revenues.
Proposal Q: Calculate a dynamic refund multiplier for flexible capacity based on a comparison of the actual ramp requirement in the interval and the ramp rate used to set the flexible capacity Reserve Capacity Requirement (RCR). Apply the greater of the peak and flexible multipliers to refunds for facilities supplying both capacity products. Require AEMO to publish the projected load ramp rate alongside the load forecast.
Proposal R: Amend the Maximum Facility Refund for DSPs to include the DSM Reserve Capacity Security. DSPs which voluntarily surrender Capacity Credits during the Capacity Year will forfeit their DSM Reserve Capacity Security in proportion to the amount of the reduction.
Proposal S: Distribute collected capacity refunds to participants, responsible for loads, rather than other capacity providers.
The EUE Target in the Planning Criterion

Stage 2 Proposals
Proposal T: Amend the target EUE percentage in the second limb of the RCM Planning Criterion to 0.0002% of annual energy consumption.
Determination of the BRCP Technology
Proposal U: The WEM Rules will continue to define the BRCP as the per MW capital cost of the new entrant technology with the lowest expected capital cost amortised over the expected life of the facility. A separate BRCP will be calculated for each of the peak capacity and flexible capacity products. The two capacity products may have a different underlying reference technology, not just different cost components. The Coordinator will review the appropriate reference technology for each capacity product and, consequently, the use of gross CONE or net CONE to set the BRCP, in 2024. The Coordinator must review the reference technology and the use of a gross or net CONE approach at least every five years, and may review it more frequently if the Coordinator considers that it has changed considerably.

1. Introduction

Clause 2.2D.1(h) of the WEM Rules confers the function on the Coordinator of Energy (Coordinator) to consider and, in consultation with the Market Advisory Committee (MAC), progress the evolution and development of the Wholesale Electricity Market (WEM) and the WEM Rules. In addition, clause 4.5.15 of the WEM Rules requires the Coordinator to review the Planning Criterion at least every 5 years.

The Coordinator, in consultation with the MAC, is reviewing the Reserve Capacity Mechanism (RCM) under clause 2.2D.1(h) of the WEM Rules. The RCM Review also incorporates the Coordinator's first review of the Planning Criterion under clause 4.5.15.

1.1 Background

1.1.1 The Performance of the RCM

The RCM has operated successfully in the WEM since 2004 by:

- providing incentives for investment in capacity that delivers the reliability outcomes valued by customers;
- reducing energy price volatility and the need for high energy price caps;
- providing confidence that reliability will be achieved by explicitly requiring capacity to be available, reducing the likelihood of costly intervention;
- incentivising entry of new types of capacity, including:
    - renewable generators, such as wind and solar;
    - Electric Storage Resources (ESR), such as batteries; and
    - Demand Side Programmes (DSP).

1.1.2 The Need for Review

The current RCM was implemented in the South West Interconnected System (SWIS) in 2004 to ensure sufficient capacity is available to maintain system reliability. The RCM has been subsequently amended to improve the initial mechanism, and to account for market and system changes.

Since the introduction of the RCM, the Planning Criterion has been reviewed twice, the last time in 2012, resulting only in minor changes because it was found to be appropriate overall.

The SWIS has changed substantially since 2012. The installed capacity of transmission connected intermittent generation has more than doubled, the estimated installed capacity of distributed photovoltaic (DPV) has increased tenfold, and more than 1,000 MW of coal and gas capacity has or is scheduled to retire by 2030.

The SWIS is now undergoing a major transition to a lower emissions energy system because of: increased penetration of DPV, the decreasing cost of renewable facilities, the Government's Renewable Energy Target, increasing pressure to reduce greenhouse gas emissions and consumers' demand for 'green' products.

At the same time, other technologies, such as battery storage, are becoming more viable and new sources of dispatchable capacity, such as Virtual Power Plants, are being trialled for future use.

Some of these capacity sources could flatten the demand profile and delay the need for additional conventional capacity to address system stress events.

Given the changes to the nature of the demand profile and electricity supply in the SWIS since the RCM was implemented, and the transition to a low emissions energy system characterised by increasing levels of intermittent and distributed generation, the Coordinator and the MAC were concerned that the current RCM design may no longer be fit for purpose.

1.1.3 Scope of the Review

The Coordinator, in consultation with the MAC, set the following conditions for the RCM Review:

- the WEM will continue to have an RCM;
- the purpose of the RCM is to ensure acceptable reliability of electricity supply at the most efficient cost; and
- any changes to the RCM should not erode the level of system reliability currently provided for by the WEM Rules.

The objective of the review is to develop an RCM that:

- achieves the system reliability that underpins the current RCM at the most efficient cost for consumers for the current and the anticipated future system demand profiles;
- addresses the issues associated with the transformation of the energy sector; and
- accounts for any transitional issues associated with any changes to the RCM.

The following aspects related to the RCM are out of scope of the review:

- the Network Access Quantity (NAQ) regime;
- the Reserve Capacity Price (RCP) regime;
- the current derating methodology for ESR; and
- the Energy Price Limits.[3]

The review is being conducted in three stages:

- Stage one focussed on the definition of reliability and the characteristics of the capacity needed in future years, including:
  - the Planning Criterion;
  - the RCM products;
  - the Benchmark Reserve Capacity Price (BRCP); and.
  - the methods for assigning Certified Reserve Capacity (CRC).[4]
- Stage two assessed how the outcomes of stage one affect implementation of other parts of the RCM, including:
  - Individual Reserve Capacity Requirements (IRCR);
  - DSPs;

[3] The Coordinator recently reviewed the Energy Price Limits as part of the WEM market power mitigation strategy.

[4] Alternative methods to assign CRC to intermittent generators were identified in stage one of the review and were assessed in stage two.

- Reserve Capacity Testing;
- outage scheduling; and
- the refund mechanism.

- Stage three will deliver draft WEM Rules amendments.

In July 2022, the Minister for Energy directed EPWA to investigate policy options to implement penalties for high emission technologies. While not part of the original scope for the RCM Review, EPWA has developed and analysed policy options in conjunction with the RCM Review. Consultation on the implementation of this policy will be conducted separately in due course.

The MAC has constituted the RCM Review Working Group (RCMRWG) to support the RCM Review's work. More information on the review is available from the EPWA website[5], including the Scope of Works for the review, the Terms of Reference for the RCMRWG, papers for RCMRWG and MAC meetings and detailed minutes for each meeting.

1.2 Purpose and Structure of this Paper

This paper consists of two parts:

- Part 1 is an Information Paper that presents the final design for elements of the RCM investigated in stage 1 of the RCM Review, that were subject to public consultation in September 2022. Part 1 is for information only, presenting the final design for:
  - the Planning Criterion;
  - the new Flexible Capacity product;
  - the BRCP; and
  - CRC methodologies for the different products and Capacity Classes.
- Part 2 is a Consultation Paper that:
  - sets out the findings and recommendations arising from stage 2 of the RCM Review, presenting proposals for changes to the design of:
    - IRCR;
    - CRC allocation and dispatch for DSPs; and
    - the testing, outages and refunds regime;
  - presents new proposals for two aspects of stage 1 scope:
    - the unserved energy target in the Planning Criterion; and
    - the party responsible for setting the BRCP reference technologies; and
  - presents a projection of the effects of the RCM changes on the commercial viability of new and existing facilities.

Part 3 includes appendices:

- Appendix A provides a summary of the feedback on the RCM Review Stage 1 Consultation Paper (Stage 1 Paper) and EPWA's responses to the feedback;

5 https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group

- Appendix B provides analysis on the proposed allocation of CRC for facilities in Capability Class 3; and
- Appendix C provides examples of the application of the new IRCR interval selection method to historical years.

1.3 Call for Submissions

Stakeholder feedback is invited on the recommended changes to the RCM from Stage 2 of the RCM Review, as outlined in Part 2 of this paper, including feedback on prioritisation for implementation of the proposals.

Submissions can be emailed to energymarkets@dmirs.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 WST on Wednesday 31 May 2023**. Late submissions may not be considered.

1.4 WEM Rule Changes

EPWA anticipates implementing outcomes of the RCM Review in at least two tranches of WEM Rule changes, and will shortly commence drafting Amending Rules to implement the review outcomes identified in Part 1 of this paper.

EPWA considers that the highest priority matters are the introduction of a new flexible capacity product and the implementation of the new method for assigning CRC to intermittent generators. The latter is dependent on the new IRCR method proposed in Part 2 of this paper, making that the highest priority item from Stage 2 of the RCM Review.

PART ONE – INFORMATION PAPER

2. Confirmation of Stage 1 Design Elements

This chapter outlines the proposals from the Stage 1 Paper and the consultation responses, and sets out the final revised design (the Review Outcomes) for:

- the Planning Criterion;
- the new Flexible Capacity product;
- the BRCP; and
- CRC methodologies for the different Capacity Classes and products.

Proposals are numbered as they were in the Stage 1 Paper. Where there is no change from the proposal, background to and rationale for the proposal can be found in that paper.

2.1 The Planning Criterion

The Planning Criterion is a key component of the RCM, as it drives the Reserve Capacity Requirement (RCR), which is the quantity of reserve capacity to be procured. Increasing the RCR reduces the risk of outages (estimated to come at a cost of around $48,100/MWh[6]) while increasing the cost to consumers of procuring Reserve Capacity.

Achieving the system reliability that underpins the current RCM at the most efficient cost for consumers, for the current and the anticipated future system demand profiles, is a key objective for the RCM Review.

The current Planning Criterion requires AEMO to procure sufficient capacity to:

- meet the forecast one in ten year peak demand, plus a reserve margin; and
- ensure that unserved energy is less than 0.002% of total annual demand.

The existing Planning Criterion has two limbs:

- a forecast peak limb, requiring sufficient capacity to meet the forecast 10% probability of exceedance (POE) peak load, plus additional amounts to manage outages, frequency keeping and Intermittent Loads; and
- an Expected Unserved Energy (EUE) limb, requiring sufficient capacity to limit EUE to 0.002% of expected demand.

The Stage 1 Paper proposed to retain the existing limbs with changes to the first limb of the Planning Criterion. Some of these changes have already been implemented.

Proposal 5

The two current limbs of the Planning Criterion will be retained, requiring sufficient capacity to:

- *meet the 10% POE demand, and*
- *achieve Expected Unserved Energy (EUE) no greater than a specified percentage of expected demand.*

6 https://www.erawa.com.au/cproot/22440/2/AAI---Attachment-6.3---Estimation-of-value-of-customer-reliability-for-Western-Power-s-network.pdf

Submissions supported retaining both limbs of the existing Planning Criterion.

Proposal 6

> *Amend the reserve margin so that:*
>
> - *sub-clause 4.5.9(a)i uses the (AEMO determined) proportion of the generation fleet expected to be unavailable at system peak due to Forced Outage, rather than a hardcoded percentage; and*
> - *sub-clause 4.5.9(a)ii refers to the largest contingency on the power system, rather than the largest generating unit.*
>
> *Introduce the proposed amendment to clause 4.5.9(a)(ii) to change the determination of the largest contingency for the calculation of the reserve margin, in time for the next 2023 Reserve Capacity Cycle (for capacity to be provided from 1 October 2025).*

Most submissions supported these changes, although one respondent expressed concern that the changes could increase the reserve margin, thus increasing costs to consumers.

AEMO raised concerns about the proposed drafting including the removal of the reference to frequency keeping capabilities in the reserve margin.

AEMO noted that the WEM Rules would need to provide guidance for its assessment of historical outages.

Proposal 7

> *The target EUE percentage in the second limb of the RCM Planning Criterion will remain at 0.002% of annual energy consumption.*

EPWA has further considered the target EUE percentage and has included a new proposal in Part 2 of this paper (see section 5.4).

Review Outcome 1

The existing limbs of the Planning Criterion will be retained.

The reserve margin was amended to refer to the largest contingency on the power system, rather than the largest generating unit by amending clause 4.5.9(a)ii. This change commenced on 1 January 2023 as part of the *Wholesale Electricity Market Amendment (Tranche 6 Amendments) Rules 2022*.

The reserve margin will be further amended by changing sub-clause 4.5.9(a)i to use the (AEMO determined) proportion of the generation fleet expected to be unavailable at system peak due to forced outages, rather than a hardcoded percentage. Amending Rules will be drafted and consulted on in stage 3 of the RCM Review.

Following further consideration of the target EUE percentage, EPWA has included a new proposal to reduce the EUE percentage in the Stage 2 Consultation Paper.

2.2 Reserve Capacity Products

The Stage 1 Consultation Paper explored different sources of system stress that the SWIS can expect to experience as the energy transition continues, and considered whether these stressors should be addressed by the RCM or through other means. Stressors that are to be addressed in the RCM must be included in the Planning Criterion, which drives the RCRs in each Capacity Year.

2.2.1 The Peak Capacity Product

Proposal 1

> *The existing 'peak capacity' product will be retained. This product provides an explicit price signal several years ahead of the need for new capacity to meet peak demand and overall energy demand.*

Submissions on the Stage 1 Paper supported retaining the peak capacity product.

Review Outcome 2

Retain the existing 'Peak capacity' product to provide an explicit price signal several years ahead of the need for new capacity to meet peak demand and overall energy supply.

2.2.2 The Flexible Capacity Product

The Stage 1 Consultation Paper set out the case for, and high-level design of, a new flexible capacity product to address the need for flexible capacity.

Proposal 3

> *Introduce a new capacity product to the RCM (alongside the existing peak capacity product) to incentivise flexible capacity that can start, ramp, and stop quickly.*

Submissions supported the introduction of a flexible capacity product.

Proposal 8

> *The RCM Planning Criterion will include a third limb requiring AEMO to procure flexible capacity to meet the size of the steepest operational ramp expected on any day in the Capacity Year from either the 10% or 50% POE load forecasts.*

All submissions supported the inclusion of a new Planning Criterion limb for flexible capacity.

Review Outcome 3

A new flexible capacity product will be introduced to the RCM.

The Planning Criterion will include a third limb requiring AEMO to procure flexible capacity to meet the size of the steepest operational ramp expected on any day in the upcoming Capacity Year from either the 10% or 50% POE load forecasts.

2.2.3 Intermittent Output Volatility

Proposal 4

> *Volatility in operational load and intermittent generation over short timeframes can be managed through ESS and re-dispatch, and the flexible capacity product will provide sufficient capacity that is capable of providing these services, so the RCM Planning Criterion will not include any reference to volatility in the output of intermittent facilities.*

Most submissions agreed, but several noted that their view could change depending on how the Essential System Service (ESS) markets develop and whether the new flexible capacity product encourages commissioning of enough ESS capable facilities. One respondent noted a desire for the costs of volatility to be paid by those causing the volatility.

ESS cost allocation is considered as part of EPWA's review of cost allocation methodologies.[7]

Facilities holding flexible capacity credits are likely to be able to, and to want to, provide some or all of the FCESS flexible capacity. They could be required to make their flexible capacity available in the relevant FCESS markets, like facilities holding Supplementary ESS Mechanism Awards. EPWA considers that, while availability obligations and refunds for flexible capacity providers should relate only to the provision of energy, it is reasonable to require them to accredit for the FCESS which they are capable of providing.

Review Outcome 4

The RCM will not include a specific product to address intermittent output volatility at this time.

The RCM Planning Criterion will not include provisions for intermittent output volatility at this time.

Facilities holding flexible capacity credits will be required to accredit for all types of Frequency Co-optimised Essential System Services (FCESS) that they are capable of providing, but will not be obligated to offer into the FCESS markets.

Proposal 2

1. *The RCM will not include a specific product to manage minimum demand.*
2. *The RCM design and the capacity certification process will seek to avoid incentives for new facilities to be configured in ways that could make minimum demand more difficult to manage, such as high minimum stable generation.*

Most submissions supported using mechanisms outside the RCM to manage minimum demand. One respondent considered that the RCM should include a product to encourage increased demand during low-load periods, and another respondent considered that EPWA's ongoing DER work and the SWIS Demand Assessment (SWISDA)[8] may identify potential for the RCM to contribute to managing low-load periods.

Submissions agreed that the RCM review should seek to avoid incentives for new facilities increasing the difficulties around managing minimum demand. One respondent suggested that the risks and benefits of facilities adding to the minimum demand challenges need to be balanced.

During stage 2, EPWA has worked to ensure that other Review Outcomes do not exacerbate minimum demand issues, including in the:

- flexible capacity certification requirements; and
- DSP availability requirements.

AEMO's ongoing procurement of Non Co-optimised Essential System Services (NCESS) for minimum demand services highlights that minimum demand remains an ongoing concern. EPWA will again consider the need for a dedicated minimum demand service as part of its Demand Side Response Review.

Review Outcome 5

The RCM will not include a specific product to manage minimum demand at this time.

7 For more information see: https://www.wa.gov.au/government/document-collections/cost-allocation-review

8 For more information see: https://www.wa.gov.au/government/announcements/swis-demand-assessment

2.3 The Benchmark Reserve Capacity Price

The Stage 1 Consultation Paper considered aspects of the BRCP.

Proposal 12

- *The administered RCM price curve for the flexible capacity product will be the same as is used for the peak capacity product, as defined in WEM Rule 4.29.1(b)(iv).*
- *The capacity price paid to a facility providing flexible capacity will never be lower than the peak capacity price.*
- *Proposed facilities will have the option to seek a five-year fixed price for flexible capacity, on the same basis as is currently available for peak capacity. A facility must opt for a fixed price for both products, it cannot select fixed price for one product and floating price for the other.*

Respondents supported using the same price curves for both the peak capacity and flexible capacity products, ensuring that facilities never receive a lower price for providing flexible capacity than for providing peak capacity, and a fixed price option for facilities providing flexible capacity.

Respondents considered that the current five-year fixed price horizon for peak capacity is too short, and should be extended to 10 or 15 years.

Respondents raised a number of additional points about RCM pricing, including that:

- broadening the conditions for fixing the RCP for flexible and peak capacity products should be considered;
- volatility in the current RCP will not support long-term investment in flexible generation and storage facilities; and
- EPWA should consider amendments to the current price cap and floor regime, and the price curve more generally, to ensure appropriate signals for participation.

While these items are outside the scope of the current RCM Review, they have been noted, and EPWA is considering them separately.

During Stage 2 of the review, EPWA has further considered the interaction of the two capacity products. Amendments to the outages and refunds regimes are covered in Chapter 5 of this paper.

Review Outcome 6

The Reserve Capacity Price for the peak capacity and flexible capacity products will be constructed using the same elements, though with different BRCPs and capacity targets.

The Reserve Capacity Price paid to a facility providing flexible capacity will never be lower than the peak Reserve Capacity Price.

Proposed facilities will have the option to seek a fixed price for flexible capacity on the same basis as is available for peak capacity.

Proposal 9

- *The ERA will remain responsible for setting the detail of the method used to calculate the BRCP.*
- *The WEM Rules will provide guidance for the ERA on the factors to be considered in setting the BRCP methodology.*

All submissions supported the Economic Regulation Authority (ERA) setting the BRCP methodology according to principles set out in the WEM Rules. One participant noted a desire for the BRCP methodology to balance investment certainty with the need for flexibility, citing an example of the Weighted Average Cost of Capital (WACC) value being inappropriately hardcoded in the WEM Procedure.

Proposal 10

- *The WEM Rules will define the BRCP as the per MW capital cost of the new entrant technology with the lowest expected capital cost amortised over the expected life of the facility.*
- *A BRCP is to be calculated for each of the peak capacity product and the flexible capacity product, and the BRCP methodology must differentiate between the two, taking into account any differences between the reference technologies used for each product, where appropriate.*
- *The ERA review of the BRCP methodology (under clause 4.16.9 of the WEM Rules) must consider the appropriate reference technology, the design life of the relevant facility, and identify any cost components that differ between the technology providing the peak capacity product only and that providing the peak capacity plus the flexible capacity product.*
- *The ERA can review the BRCP methodology more frequently than every five years if it considers that the reference technology has changed significantly, and must consult with stakeholders each time it does.*

EPWA has further considered the approach to setting the reference technology for the BRCP and has included a new proposal in Part 2 of this paper (see section 5.5).

Proposal 11

- *Where the RCM reference technology has the highest short-run costs in the fleet, the BRCP methodology can use the simpler gross CONE approach, as this will be the same as the net CONE.*
- *Where the RCM reference technology does not have the highest short-run costs in the fleet, the use of net CONE approach would need to be considered together with all other factors that may influence investment decisions.*
- *The BRCP will be set based on a facility located in the least congested part of the network. If there is no uncongested network location to accommodate the size of the lowest fixed cost technology, the NAQ regime may affect the choice of reference technology. This location will be considered as part of the ERA's regular review of the BRCP methodology.*

Respondents supported retaining a gross cost of new entry (CONE) approach. Two respondents opposed a move to net CONE at any point in time. Respondents understood the rationale for a potential move to net CONE in future, but were concerned that a move to net CONE could result in:

- reduced investment certainty, due to the difficulty in forecasting energy and ESS revenues as intermittent generation continues to increase;
- new entrants being unable to recover their capital costs; and
- significant additional complexity for negligible benefit.

Respondents proposed that a move to a net CONE be:

- preceded by additional consultation and analysis; and
- held off until experience with a new reference technology can inform modelling assumptions.

One respondent requested that the reference facility location instead be in ‘any suitable uncongested part of the network’, to avoid unnecessary analysis to determine which location was the least congested.

Review Outcome 7

Further consideration was required on the approach to setting the reference technology for the BRCP. EPWA has included a new proposal in the Stage 2 Consultation Paper.

The BRCP will be set based on a facility located in an uncongested part of the network. If there is no uncongested part of the network, the BRCP will be set based on a facility located where there is limited congestion.

The guidance in the WEM Rules will set out the principles and process steps to determine parameter values instead of recording fixed parameter values, especially where those parameters are likely to change markedly from year-to-year.

The WEM Rules will not specify the use of gross or net CONE, but will specify that any move away from gross CONE must be accompanied by analysis and consultation.

2.4 Capacity Certification

The Stage 1 Consultation Paper considered various aspects of capacity certification.

2.4.1 Capability Classes

Proposal 13

- *The current Availability Classes will be removed from the WEM Rules.*
- *The RCM will allocate facilities to one of three Capability Classes:*
    - *Class 1: Unrestricted firm capacity;*[9]
    - *Class 2: Restricted firm capacity;*[10] *and*
    - *Class 3: Non-firm capacity*[11]

[9] A Capability Class 1 facility must be firm, dispatchable capacity with no fuel supply or availability limitations such that, if dispatched, it could run at maximum output for at least 14 hours. Capability Class 1 facilities would be required to be available at all times (except when on outage), offer into both STEM and Real-Time Markets as is currently the case for Scheduled Facilities, and be subject to capacity refunds if they fail to do so.

[10] A Capability Class 2 facility must be firm, dispatchable capacity that is not eligible for Capability Class 1 due to fuel supply or availability limitations. This might include a storage facility which is energy limited, a Demand Side Programme which is only available at certain times of day or a dispatchable facility that has restrictions on fuel supply. Capability Class 2 facilities would receive lower CRC based on their availability limitations, and would be required to be available during specified hours, offer into STEM and Real-Time Markets in those hours, and be subject to refunds if they fail to do so.

[11] A Capability Class 3 facility is one which does not provide firm, dispatchable capacity, such as a wind or solar farm without collocated firming capacity. Capability Class 3 facilities would not have availability obligations (as is currently the case for Semi-Scheduled Facilities) but would expect to have significantly lower ratio of CRC to nameplate capacity than facilities in the other Capability Classes.

- *CRC allocation methodologies will be amended to consider hybrid facilities as a single entity.*
- *Capability Class 1 facilities will be required to demonstrate sufficient fuel to run for 14 hours.*
- *Capability Class 1 facilities will be required to be available during all dispatch intervals, unless on an outage.*

Proposal 17

- *The methodology to assign CRC to facilities in each of the different Capability Classes will differ as follows:*
  - *Class 1: Expected output at projected 10% POE peak ambient temperature;*
  - *Class 2: Expected output at projected 10% POE peak ambient temperature, adjusted for required availability duration; and*
  - *Class 3: To be confirmed in stage two of the RCM Review.*

Most submissions supported the new Capability Classes, and the amendment of CRC allocation methodologies to consider a hybrid facility as a single entity. One respondent considered that Capability Classes should not group together different products that offer different reliability value and that those products should be priced differently. Participants raised concerns about:

- how the certification process would work for hybrid facilities;
- revenue sufficiency for hybrid facilities; and
- participant's ability to implement their preferred operational arrangements for hybrid facilities, including the use of collocated storage.

One respondent considered that prioritising new facilities by Capability Class may not be necessary and could oppose the new WEM objective to decrease carbon emissions.

While there is some additional detail to be considered on the implementation of testing, dispatch and outage scheduling for hybrid facilities, EPWA considers that further changes will be primarily driven by the requirements of the facility's Capability Class. This will be covered during the rule drafting process.

Two submissions supported retaining the 14-hour fuel requirement. However, most submissions did not support retaining a 14-hour fuel requirement, arguing that:

- availability is sufficiently incentivised by the refund regime and the need to earn energy revenue;
- the requirement is based on the expected distillate resupply time which is no longer an appropriate benchmark;
- the requirement increases costs to capacity providers;
- a 14-hour duration gap will only occur once all thermal generation has retired; and
- the fuel requirement should be based on the forecast duration gap.
- AEMO's interpretation of the requirement is too onerous;
- the fuel requirement should be replaced by a 4-6 hour fuel requirement to match with the current duration of the peak; and
- if retained, the obligation should not apply at the time of certification but from the time the facility commences operation and Reserve Capacity Testing.

The 14-hour requirement stems from AEMO's implementation of the current Availability Class definitions in WEM Rule clause 4.11.4. The WEM Procedure[12] requires participants to demonstrate firm fuel availability for peak Trading Intervals (8am-10pm) on all Business Days. This procedure was reviewed and updated in December 2022, and the requirement was reconfirmed.

EPWA has considered the submissions and remains concerned that relaxing the requirement to show evidence that generation facilities have sufficient fuel to operate during periods of system stress would risk reducing the level of reliability provided for by the WEM Rules, and that doing so would be counter to one of the key principles of the RCM Review.[13]

Recent fuel supply issues illustrate the importance of fuel availability and recent changes as part of the Market Power Mitigation Strategy[14] mean that participants now have certainty that the costs of long-term take-or-pay fuel contracts can be reflected in market submissions.

The fundamental reason for having three Capability Classes is to recognise that facilities with firm availability provide a greater contribution to system reliability than those with lower availability. Participants who wish to procure shorter duration fuel contracts can instead seek certification in Capability Class 2 and receive a pro-rated CRC accordingly, with fuel availability obligations in fewer hours than faced by facilities in Capability Class 1. This will enable the participants to reduce their fuel contract costs.

However, EPWA acknowledges that the current WEM Procedure may be more restrictive than is warranted to ensure fuel availability during times of system stress. The current WEM Procedure requires demonstrating fuel availability during the midday trough, when it is increasingly likely that the majority of the facilities will be dispatched down or off. In future, it will be more appropriate for the WEM Procedure to focus on the availability gap – the period over and after the peak demand– rather than periods in the middle of the day.

EPWA considers that the WEM Rules could provide additional guidance on the implementation of the provisions in clause 4.11.4(a)ii such that AEMO should consider the time of day in which certification in Capability Class 1 requires firm fuel contracts, particularly as the overnight duration gap extends (see section 2.4.2). Offer obligations, testing requirements, and refund incentives will remain in place.

Most submissions generally supported the use of different methods to set CRC for the three Capability Classes. The only aspect of Capability Class 1 certification raised was the proposed change to the temperature rating requirement. Some respondents considered that a move from 41 degrees to the 10% POE peak ambient temperature was not necessary, as the peak load has moved later in the day in recent years, when ambient temperatures have started to decline.

Review Outcome 8

The current Availability Classes will be replaced with new Capability Classes:

- Class 1: Unrestricted firm capacity;
- Class 2: Restricted firm capacity; and
- Class 3: Non-firm capacity.

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12 https://aemo.com.au/-/media/files/electricity/wem/procedures/certification-of-reserve-capacity-for-the-2022-and-2023-reserve-capacity-cycles.pdf

13 That any changes to the RCM should not erode the level of system reliability currently provided for by the WEM Rules.

14 https://www.wa.gov.au/government/document-collections/market-power-mitigation-strategy

Hybrid facilities will be assessed as a single entity.

Facilities holding Capacity Credits in Capability Classes 1 and 2 will continue to have obligations to offer into the STEM and Real-Time Markets, undergo capacity testing, and pay refunds when not meeting their obligations.

Review Outcome 9

Capability Class 1 facilities will be required to be available during all Dispatch Intervals, unless on an outage, and the requirement to demonstrate sufficient fuel for 14 hours of daily operation will be retained.

Capability Class 1 capacity will be assigned CRC based on its expected maximum output at 41 degrees.

2.4.2 Capacity Certification – Capability Class 2

Proposal 14

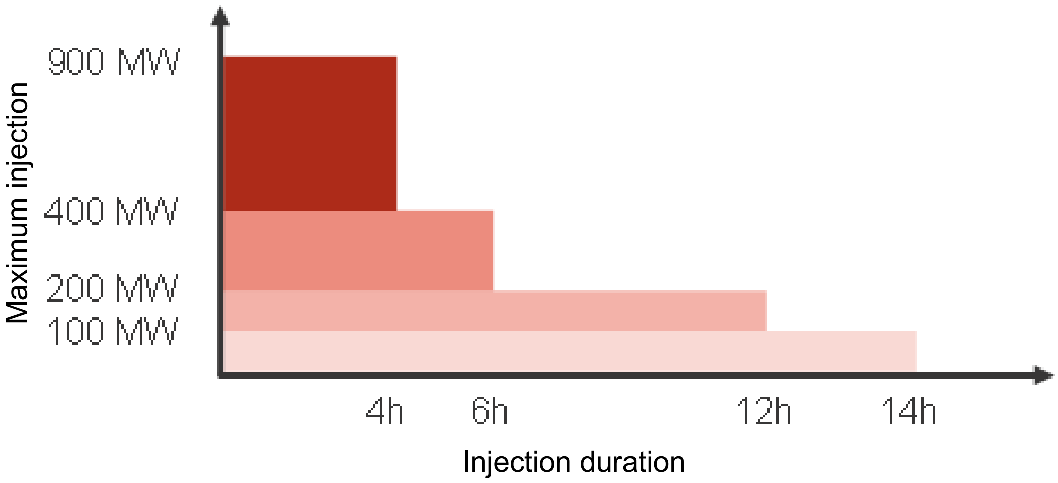
- *AEMO will determine an availability duration requirement for new Capability Class 2 facilities, based on the capacity of the existing and committed fleet, and publish it in the Electricity Statement of Opportunities (ESOO), including forecasts for subsequent years.*
- *Capability Class 2 facilities will receive peak CRC equal to their maximum instantaneous output pro-rated by the number of hours they can sustain this output divided by the availability duration requirement.*
- *Proponents can request a five-year fixed availability duration requirement for a Class 2 facility but this request will only be accepted if the facility is needed to meet the reserve capacity target.*

In the Stage 1 Consultation Paper, EPWA proposed to use an availability duration target in setting CRC for Capability Class 2 facilities. Under this approach the duration gap is assumed to be met by either generation (primarily overnight wind in later years) or by increasing storage volumes to allow a longer discharge period.

Submissions raised alternative options for Capability Class 2 certification. These are discussed further below.

Some respondents suggested that AEMO could instead separate the duration requirement into several parts and select Capability Class 2 capacity of multiple durations to fill the aggregate requirement, as shown in Figure 1.

Figure 1: Shaped Procurement of Energy Limited Capacity



The same peak requirement would be procured, but the evolving shape of the post-peak would be accounted for by procuring capacity from facilities with a range of availability durations. Rather than prorating the MW based on duration, the duration would become a payment multiplier. Capability Class 1 facilities would get a 100% price multiplier, and a 6h facility would receive a 6/24 multiplier. Prorating reserve capacity payments should have the same overall effect on the facilities RCM revenue as prorating their certified capacity.

EPWA considers that this approach is not appropriate as it would:

- be unfair to Capability Class 1 facilities or move away from providing each MW of CRC available at peak with the same payment (which would add complexity);
- move towards treating capacity as a MWh contribution instead (at least for Capability Class 2); and
- move the RCM towards a MWh target rather than a MW target.

One respondent considered that the duration gap should be addressed outside of the RCM.

The RCMRWG suggested a third approach - defining another capacity product to explicitly deal with the duration gap.

Under this option, the capacity mechanism would distinguish between peak capacity, flexible (ramping) capacity, and duration capacity. It would provide additional incentive for filling the duration gap, rather than derating the capacity based on its availability. Such a duration product would specify availability over a certain number of hours (determined by AEMO and published in the ESOO), extending over time to eventually span the entire peak and overnight period.

The MAC considered that this approach has merit, but does not need to be addressed immediately, because:

- the duration gap is a function of the type and size of facilities participating in the market, rather than an uncontrollable factor such as increasing DPV penetration;
- short-term storage is projected to be sufficient to cover the SWIS needs for the next decade; and
- with each additional incentive signal the market provides, the less each signal factors into investment decision making. The new flexibility product will provide an important signal, and this should be introduced and given a chance to take effect before another capacity product is introduced.

EPWA considers that the relevant duration requirement used in prorating the capacity of Capability Class 2 facilities should match the Capability Class 1 requirement. The existing method for Capability Class 2 facilities consisting solely of ESR components will remain unchanged as per the scope of the RCM Review.

In the submissions, stakeholders also considered that it would be important for the ERA's BRCP methodology to align with AEMO's availability duration calculations. Several respondents considered that a five-year fixed duration would not align with the expected life of facilities providing flexible capacity, which are expected to have at least a 10-year investment life. Two respondents considered that there should not be any conditions for the ability to lock in a fixed duration requirement.

EPWA acknowledges the concern over a mismatch between the time/technical parameters that affect revenue and the expected life of an investment, particularly in relation to longer duration storage facilities. EPWA is examining this issue separately.

Review Outcome 10

The availability duration requirement for new Capability Class 2 facilities that are not DSPs and do not consist solely of ESR components will be 14 hours, to match the Capability Class 1 fuel availability requirement.

Capability Class 2 capacity will be assigned CRC based on its expected maximum output at 41 degrees, pro-rated by the number of hours it can sustain this output divided by the 14-hour availability duration requirement.

Capability Class 2 facilities which consist solely of ESR components will continue to be assessed based on the linear derating method, which may have a different number of hours required. Proponents can request a five-year fixed availability duration requirement for an ESR facility.

DSPs will continue to be assessed based on a 12-hour availability requirement.

AEMO will forecast the availability duration gap based on the capacity of the existing and committed fleet, and will publish it in the ESOO, including forecasts for subsequent years.

The WEM Rules will set metrics to identify if the duration gap is at risk of not being met in future years and require AEMO to monitor and publish these metrics.

The Coordinator's reviews in WEM Rule 4.13B will include consideration of:

- availability duration gap metrics; and
- availability duration requirements for ESR and DSP facilities.

2.4.3 Capacity Certification – Capability Class 3

The output of intermittent generators is inherently uncertain, varying from interval-to-interval and from year-to-year. No CRC allocation method will perfectly predict the output of an intermittent facility in a future period of system stress, based on historical output data. CRC allocation will always be an estimate of the expected contribution.

EPWA's objective when developing the method was to identify a CRC allocation method for intermittent generators that:

- ensures that the system reliability objective is met;
- adequately assesses facilities' contribution to system reliability;
- minimises year-to-year volatility for investors;
- is simple and easy to understand;

- ideally can be replicated by potential investors and other stakeholders;
- is consistent with the calculation of IRCRs; and
- ideally can be adapted for use for DSPs[15].

Most respondents were supportive of amending the current Relevant Level Method for CRC allocation to intermittent generators, but differed in their views on a suitable replacement with three respondents supporting the method proposed by Collgar in the RCMRWG. Alternative methods for allocating CRC to Capability Class 3 facilities were further explored and consulted on during Stage 2 of the review.

Overall Approach

The approach to determining intermittent facility CRC can be separated into two parts:

(1) Determining the total CRC to be allocated to the fleet as a whole; and

(2) Determining how to allocate the total CRC across all facilities.

The Stage 1 Consultation Paper identified two methods that used effective load carrying capability (ELCC) to set the total CRC to be allocated to the intermittent fleet, and one that assessed each facility individually, without considering the overall contribution of the fleet. Submissions and subsequent discussions at the RCMRWG and the MAC concluded that an approach which considered the overall fleet contribution was appropriate, and EPWA did not consider the individual facility assessment any further.

Respondents also noted a desire to mitigate year-to-year volatility in CRC outcomes as smoothing out year-to-year volatility in fleet ELCC could improve certainty for investors. One respondent considered that the method for assigning CRC to intermittent generators should reflect their contribution to system reliability and provide strong incentives to firm up intermittent capacity.

EPWA remained concerned that any method for reducing volatility should not cause CRC allocations that overstate performance by increasing the weight placed on performance in lower stress periods. As a result, the proposed fleet ELCC process will include measures to reduce year-to-year volatility while maintaining focus on high stress periods.

Setting the Fleet CRC

Volatility due to unusually high performance in a single year can be mitigated by setting the fleet ELCC to the lower of:

- the fleet ELCC calculated for the whole period; and
- the average of the fleet ELCCs calculated for each individual year of the period.

Some years do not have any significant stress periods. The effect of low stress periods can be mitigated by removing the year with the lowest peak from the data used to calculate CRC. For example, 2018 has the lowest peak demand of any year in the period 2015 to 2021 - approximately 300 MW lower than any other year, and 750 MW lower than the highest peak interval.

EPWA has used an EUE approach to calculate the fleet ELCC,[16] using the target from the second limb of the Planning Criterion. This approach is less reliant on firm facilities than a cumulative outage probability table, so is more suitable for systems with high intermittent penetration.

15 See Chapter 4 for further discussion.

16 See the Stage 1 Paper for more detail on the ELCC method.

Table 3 shows the results for several different EUE targets for the load scaling step. The approach gives similar results across a range of EUE targets, including the current and proposed Planning Criterion EUE target. For very small EUE target parameters, the calculated fleet ELCC becomes less consistent, as it is driven by a smaller and smaller number of intervals.

Table 3: Fleet ELCC (2016-2020 less 2018) for different EUE Targets, with Stochastic Sampling of Forced Outages over 250 Iterations

EUE Target	Fleet ELCC (MW)	Number of intervals with EUE, intermittent generators included	Number of intervals with EUE, intermittent generators removed
0.00000%	288	1	1
0.00005%	280	12	12
0.00010%	255	19	23
0.00015%	251	27	34
0.00020%	247	33	44
0.00050%	246	63	88
0.00100%	248	109	151
0.00150%	249	147	201
0.00200%	252	178	247
0.00400%	259	293	406
0.01000%	271	569	748

Allocating the Fleet CRC to Individual Facilities

Most submissions indicated a preference to allocate the fleet ELCC based on performance during system peak intervals. Four respondents considered that existing facilities should be protected from new facilities ‘stealing’ their CRC if they have high generation during peak demand but do not increase the fleet ELCC.

During stage 2 of the review, EPWA carried out additional analysis on four options for CRC allocation to intermittent generators:

- the Delta ELCC Method, where first-in and last-in facility ELCCs are calculated and used to distribute the fleet CRC;
- the EPWA Hybrid Method, where the fleet CRC is distributed based on facility performance in stressed intervals, using Load for Scheduled Generation (LSG) as the metric for which intervals to consider;
- the Collgar Hybrid Method, where the fleet CRC is distributed based on facility performance in stressed intervals, using total demand as the metric for which intervals to consider; and
- the IRCR Method, where the fleet CRC is distributed based on facility performance during the IRCR intervals.

Analysis for the four methods is captured in RCMRWG papers. Ultimately, EPWA (in consultation with the MAC and the RCMRWG) has determined to use the simpler IRCR method. This makes it easier for participants and investors to apply the method themselves, and aligns incentives for capacity suppliers and consumers.

The approach to selecting IRCR intervals was also discussed with the RCMRWG, and is presented for consultation in section 3.2 in Part 2 of this paper.

This approach, in conjunction with the fleet ELCC determination, will address all the policy design goals listed in section 2.3.4.

Review Outcome 11

The fleet CRC is to be set as follows:

(1) Take historical load for the most recent 5 Capacity Years, and adjust it to account for:

 (a) output profiles of current levels of DER; and

 (b) DSP dispatch, unserved energy and use of Supplementary Reserve Capacity (SRC) and NCESS.

(2) Take historical generation output for each Capability Class 3 facility for the same period, and adjust it to remove the effects of any involuntary curtailment (whether this is economic curtailment by the clearing engine, network constraints, or AEMO direction).

(3) Remove data from the Capacity Year with the lowest peak demand.

(4) For the whole remaining dataset, and for each individual year in the remaining dataset, calculate the initial Fleet effective load carrying capability (ELCC) as follows:

 (a) increase or decrease demand by adding or subtracting the same MWh quantity in each interval to the point at which expected EUE is at the level specified in the Planning Criterion, assuming that:

  (i) Capability Class 1 and 2 facilities have no planned outages;

  (ii) Capability Class 1 and 2 facilities suffer forced outages at historic rates;

  (iii) there are no network constraints;

 (b) remove all Capability Class 3 facilities from the generation fleet;

 (c) reduce load until the EUE is the same MWh quantity as it was in step (4)(a); and

 (d) set the fleet ELCC to the quantity of load reduced in each interval, converted to MW.

(5) Set the fleet CRC as the lower of:

 (a) the fleet ELCC for the whole dataset; and

 (b) the average of the fleet ELCCs for each individual year.

Expert Reports

Proposal 16

> *To ensure independent estimates of intermittent generator output in historical periods, AEMO will procure expert reports to derive estimates of on behalf of participants.*

Only one respondent supported AEMO procurement of independent reports. Other respondents disagreed with the proposal, noting that:

- the expert report is integral to the project development, approval and financing process, including more than just the estimated output values used for CRC, so having a third party

(AEMO) procure the estimated output report would compromise those core project activities and increase overall costs;

- AEMO would be in a difficult legal position if the expert's work is subsequently challenged as having led to an "incorrect" investment decision;
- there are explanations other than bias for a decline in CRC levels over time, including the Relevant Level Methodology (RLM) itself, as the output of a new intermittent generator only impacts the timing of peak LSG intervals (thus shifting the periods used) once it is operational;
- AEMO would be procuring reports from the same set of qualified experts as participants, so they would be unlikely to give significantly different results;
- AEMO would need to manage conflicts of interest among experts, as some are likely to be engaged by competing participants on different developments; and
- it would be more practical to have AEMO raise any discrepancies between the expert report and actual output directly with the participant or the independent expert.

If AEMO were to procure the reports, respondents considered that:

- proponents should be allowed to interrogate and approve assumptions, data quality, and report outcomes prior to finalising;
- AEMO must have processes in place to manage conflicts of interest;
- AEMO must have processes in place to ensure efficient costs; and
- costs should be recovered from project proponents on a 'causer pays' basis.

EPWA acknowledges the complexities in separating this report from the project development and financing process, but considers that additional measures are required to ensure the impartiality of these reports as overly optimistic expert estimates are a risk to power system reliability.

Review outcome 12

Participants will continue to procure their own expert reports.

AEMO will have powers to audit report accuracy:

- AEMO will be able to seek independent review of any submitted report and may reject the report if the figures appear to be inflated; and
- once a facility is operational, AEMO will compare actual performance with projected performance, and may remove experts from its approved list if their estimates are persistently inaccurate.

2.4.4 Certification of Facilities Providing Flexible Capacity

During stage 2 of the RCM Review, EPWA considered the market mechanisms required to implement a flexible capacity product, particularly capacity certification and facility dispatch. These issues were discussed with and were generally supported by the RCMRWG, and are included below for information.

Flexible capacity requirements will be incorporated into the existing ESOO and certification processes.

A facility will not be able to be certified for flexible capacity only, it must also provide peak capacity.

Minimum performance requirements for the flexible capacity product will likely change over time as the load shape changes. The WEM Rules will require AEMO to consider, as part of the ESOO processes, the capability required of facilities to meet the identified need, ensuring that providers of the flexible capacity can move quickly from no output (or from full consumption) in the midday to rapidly increase output (or decrease consumption) as the high ramp requirements begin.

Dispatch of Facilities Providing Flexible Capacity

Under the Real-Time Market Rules from the New WEM Commencement Day, there is no specific market service for fast-ramping facilities. This means that there is no explicit consideration of whether to hold flexible capacity in reserve for use in later periods. However, the dispatch algorithm will account for ramp constraints and start-up times when dispatching facilities for energy and will, subject to network constraints, dispatch the lowest cost facilities for energy ahead of higher cost facilities. This means that, as long as sufficient flexible capacity is available, the dispatch engine will be able to use it when needed.

In the SWIS, fast ramping facilities are currently more expensive than slower ramping ones, meaning they will effectively be held in reserve unless needed. If slow ramping facilities ever became more expensive than fast ramping facilities, it would be possible for the dispatch engine to dispatch a faster facility ahead of a slower one, and then not have sufficient ramping capability available in a later period.

This risk could be mitigated by implementing a dedicated ramping service, but doing so would require inter-temporal optimisation, whereby the clearing engine optimises dispatch costs over multiple intervals rather than sequentially interval-by-interval, as at present.

This would require major changes to the dispatch algorithm and is not necessary at this time. If centralised commitment is implemented in the future, a ramping service could be implemented at the same time.

The MAC supported this approach.

Review Outcome 13

The quantity of flexible CRC allocated to a facility will be capped at:

- its CRC for peak capacity; and
- the maximum MW quantity that it could reach four hours after being dispatched from a cold start.

The WEM Rules will require AEMO to set maximum standards for:

- minimum stable loading level;
- start time (time from receiving a Dispatch Instruction when in a “cold” state to reaching the facility controllable range);
- minimum running time (time from receiving a Dispatch Instruction when in a “cold” state to turn on, run, and turn off again);
- stop time (time from receiving a Dispatch Instruction when running at the minimum of its controllable range to ramp down to zero output); and
- restart time (time from desynchronising to synchronizing).

The minimum stable loading level is particularly important for the effectiveness of this product, and is likely to be 10% of the facility nameplate capacity or less.

Facilities providing flexible capacity will be dispatched for energy through the already established dispatch algorithm, and will not be explicitly held in reserve for later use.

2.4.5 Treatment of Outages

Proposal 15

- *CRC allocation will remain on an Installed Capacity (ICAP) basis, with refunds payable for any forced outage.*
- *The reserve margin in the first limb of the Planning Criterion will be set at the greater of the fleet-wide Equivalent Forced Outage Rate on Demand (EFORd) and the largest contingency expected at system peak, with AEMO assessing both each year.*
- *Where, over a three-year period, a facility has an EFORd higher than 10%, AEMO will be required to reduce its CRC by the EFORd.*
- *The method for calculating EFORd will also account for forced outages reported at times the relevant facility had not been called to run.*
  - *A facility whose CRC has been reduced under clause 4.11.1(h) will be excluded from the calculation of fleet outage rate for the purposes of setting the Planning Criterion reserve margin.*

All submissions supported continuing to allocate CRC on an ICAP basis. Some respondents supported the reduction of CRC for facilities with high EFORd, others disagreed on the basis that CRC allocation should be forward looking rather than backward looking. Several respondents thought it is necessary to allow AEMO discretion for how to account for outages which would not reasonably be expected to present a risk to the capacity provider's ability to provide CRC into the future.

EPWA agrees that CRC allocation should be based on the expected future ability of a facility to provide capacity, but still considers that it is necessary to strengthen the CRC derating requirements in clause 4.11.1(h). EPWA accepts that the historical outage rate may not represent expected future outage rate, and will include some discretion for AEMO to not apply the derating if it is satisfied that the underlying reason for the outage has been addressed.

Review Outcome 14

CRC allocation will remain on an Installed Capacity (ICAP basis), and the reserve margin will be set accordingly, excluding facilities which have had their CRC reduced due to a high Equivalent Forced Outage Rate on Demand (EFORd).

If over a three-year period a facility has an EFORd higher than 10%, AEMO will be required to reduce its CRC by the EFORd, unless it has evidence that the underlying reasons for the high outage rate have been resolved.

PART TWO – CONSULTATION PAPER

3. Individual Reserve Capacity Requirements

3.1 Introduction

The IRCR calculation determines how much each participant contributes to the cost of procuring reserve capacity.

EPWA's goal is to identify an IRCR determination method for participants who are responsible for loads that:

(1) ensures that capacity payments are fully recovered from electricity consumers;

(2) allocates costs based on consumers' contribution to the RCR;

(3) provides a signal to consumers to amend their electricity use in a way that reduces the RCR;

(4) allows costs to be allocated to new loads added during a Capacity Year, which may provide no or minimal notice of coming online;

(5) is simple, cost effective, and easy to understand;

(6) ideally aligns with the method(s) used to allocate CRC;

(7) ideally minimises year to year volatility for consumers;

(8) ideally can be replicated by potential investors and other stakeholders; and

(9) is predictable so it incentivises effective management of load during system stress events.

3.2 IRCR for Peak Capacity

3.2.1 Current Approach

Methodology

IRCR is calculated monthly for each participant as follows.

Firstly, determine the representative load for each meter:

- If the meter was measuring load during the Hot Season in the previous Capacity Year (08:00 on 1 December to 08:00 on 1 April), the representative load is the median load in 12 intervals selected from the previous hot season as follows:
    - For each of the 4 trading days in the hot season with the highest maximum demand[17] in any Trading Interval, the 3 Trading Intervals with the highest Total Sent Out Generation.
- If the meter was not measuring load during all of the 12 selected intervals, its representative load is its median load in 4 intervals selected from month n-3 as follows:

[17] Total Sent Out Generation is used as a proxy for total demand, as this figure includes all system losses.

- the four intervals with the highest Total Sent Out Generation from that month;
- multiplied by 1.3 if it is a Temperature Dependent Load (TDL) and 1.1 if it is a Non-Temperature Dependent Load (NTDL) – this allows for expected increase in the hot season months; and
- pro-rated to the proportion of the month that the meter measured load.

Secondly, sum the representative TDLs and NTDLs for each participant, with another ratio applied to account for meters which were present in the previous hot season.

Finally, allocate IRCRs to participants in proportion to their total load, so that the total sums to the RCR.

Only Time of Use (TOU) meters are explicitly included. All remaining meters are represented by the "Notional Wholesale Meter", which is the total generation less demand measured by TOU meters. The Notional Wholesale Meter is treated as a Temperature Dependent Load.

Issues with the Current IRCR Method

The current IRCR method does not consider demand in all system stress intervals. As the analysis in section 3.2.3 shows:

- in some years, the highest demand intervals are spread across six or seven days. The current IRCR method only considers four days in the Hot Season.
- in some years, the highest demand intervals are concentrated on one or two days. The current IRCR method would include only three intervals on each selected day, meaning that high demand intervals are excluded in favour of lower demand intervals; and
- sometimes, system stress occurs in lower demand intervals where lower available capacity means a lower reserve margin. The current IRCR method does not consider the size of the reserve margin.

There is opportunity to amend the IRCR calculation to better align with system stress periods.

3.2.2 Alternative IRCR Options

EPWA identified five options for determining the IRCR:

(1) Equivalent firm capacity, similar to ELCC;

(2) Ex-ante notification, where AEMO announces a day or so in advance that certain intervals will be IRCR intervals;

(3) Ex-post interval selection based on reserve margin, similar to how the dynamic capacity refund rate is calculated;

(4) Ex-post interval selection based on peak load, similar to the current method; and

(5) A two-pronged metric, using both base and peak demand.

The options were discussed with the RCMRWG and the MAC. Each option is set out in more detail below.

Option 1: Equivalent Firm Capacity

It would be possible to apply an ELCC-like approach at a participant portfolio level as follows:

(1) Using historical load and historical intermittent fleet output adjusted as discussed in section 2.4.3, adjust load up or down to find the load level at which EUE is at the level specified in the Planning Criterion.

(2) For each participant:

- sum all Associated Loads, resulting in an interval-by-interval demand profile;
- subtract the interval-by-interval demand profile from the interval-by-interval historical load;
- increase demand until EUE is at the same level it was in step 1;
- set the participant's Equivalent Firm Capacity to the MW quantity of demand added.

(3) Allocate IRCR in proportion to Equivalent Firm Capacity, so that the total IRCR allocated equals the RCR.

This approach would not be very transparent to participants, servicing loads, as it would not allow a common set of intervals to be used for CRC allocation.

IRCR could be recalculated daily to account for switching.

Option 2: Ex-ante Notification by AEMO

Under this option, IRCR would be allocated based on participant withdrawals in specific intervals.

AEMO would designate specific upcoming intervals as "performance intervals", with some hours advance notice.

This option would give AEMO flexibility to respond to specific circumstances, but it would need to develop procedures to define how it would use this flexibility. AEMO would be restricted to a certain number of days on which it could designate intervals.

This approach would mean:

- intervals less likely to be designated early in the Hot Season (as AEMO 'saves up' intervals in case of greater need later) and more likely to be designated later in the Hot Season (as AEMO is freer to 'use up' remaining intervals);
- different numbers of performance intervals in each year;
- potential for no performance intervals to be called in a mild year; and
- potential for AEMO to call performance intervals based on a load forecast that does not eventuate.

Option 3: Ex-post Intervals by Reserve Margin

Under this option, IRCR would be allocated based on participant withdrawals in the intervals with the lowest reserve margin.

AEMO would publish reserve margin data.[18] Participants would need to monitor this data and judge whether each interval could potentially affect their IRCR allocation, and whether to reduce demand accordingly.

Given that the projected reserve margin can change at short notice based on facility Forced Outages (which consumers do not have any control over), consuming participants would need to be more responsive to system conditions to manage their IRCR exposure.

Over time, this method would be likely to identify more intervals in shoulder seasons than a demand-based method. It would also be less predictable than a demand-based method, as historical outage data is less predictive of future outages and fuel supply issues than historical demand data is of future demand.

The method could be made more predictable by excluding Forced Outages (and potentially Planned Outages), but consuming participants still have no control over intermittent generation output.

Option 4: Ex-post Intervals by Demand

Under this option, IRCR would be allocated based on participant withdrawals in the intervals with the highest demand.

This option has the same approach as the current method, but it is possible to adjust the interval selection method to better capture the pattern of system stress events in the SWIS.

This option would be more predictable than a reserve margin based method, and over time, would be less likely to identify intervals outside the summer Hot Season.

Option 5: Two-pronged Metric

During the RCMRWG, one participant suggested another option, where capacity costs are allocated in two tiers to reflect that consumers receive value for reliability outside the peak:

(1) one tier relating to demand at peak times, calculated as per the previous options; and

(2) a second tier relating to consumption at other times – for example, calculated as the mean demand for the year, or consumption at the time of lowest demand.

This option would mean that participants have less incentive to reduce their demand at peak, but, potentially, a new incentive to reduce their overall demand.

Assessing the Options

Table 4 provides an assessment of each option against the policy goals.

18 Firm capacity, plus actual intermittent output, minus demand.

Table 4: Qualitative Comparison of IRCR Approaches[19]

Goal	1. Equivalent firm capacity	2. Ex-ante notification	3. Ex-post by reserve margin	4. Ex-post by demand	5. Two-pronged metric
Capacity payments fully recovered from consumers	●	●	●	●	●
Allocates costs based on contribution to the RCR	●	◕	◕	●	◔
Provides a signal to amend electricity use in a way that reduces the RCR	●	◕	◕	●	◕
Allows costs to be allocated to new loads added during a Capacity Year	●	●	●	●	●
Simple, cost effective, and easy to understand	◑	●	◕	●	◕
Aligns with CRC methodology	◑	◕	◕	◕	◔
Minimises year to year volatility	◑	◑	◑	◑	◕
Can be replicated by potential investors and other stakeholders	◑	◔	●	●	◕
Is predictable so it incentivises effective load management during system stress events	◑	◔	◑	◕	◕

All options allow capacity payments to be fully recovered from consumers, and all can account for new loads being added during a Capacity Year.

The RCR is set according to the Planning Criterion. Options 1 and 4 come closest to allocating costs by consumer contribution to the RCR. Options 2 and 3 are less directly related to the way the RCR is calculated, and so the signal they provide is less likely to result in a reduction in the RCR. Option 5 allocates only part of the costs by contribution to the RCR.

19 A complete circle indicates that the option fully achieves the goal, an empty circle indicates that the option does not achieve the goal at all, and a partial circle indicates that the option partially achieves the goal.

Options 2 and 4 are both relatively simple, while option 1 is the most complex. Options 3 and 5 fall in between. Options 3 and 4 are the easiest for stakeholders to replicate.

Option 1's ELCC-like calculation is aligned with the fleet part of the intermittent generation methodology but would not provide intervals to be used in allocating the fleet ELCC across individual facilities (as discussed in section 2.4.3). All other options would provide a set of intervals which could be used in the CRC methodology.

With a single year lookback, all methods are likely to have some volatility, but only insofar as consumption profiles are volatile.

Option 4 should be reasonably predictable, while ex-ante notification (Option 2) would be most difficult to forecast for a future year.

Option 5 would dilute the incentive for participants to manage their consumption at times of system stress and is not aligned with a causer-pays philosophy.

The MAC supported continuing to use contribution to load in high demand intervals as the basis for setting IRCR.

Proposal A:

Continue to set participant IRCR based on contribution to load in high demand intervals.

Consultation Questions:

(1) Do stakeholders support determining IRCR based on contribution to high demand intervals?

3.2.3 Characteristics of High Load Periods

While participant consumption during high demand intervals reflects their contribution to the RCR, the current IRCR selection methodology does not necessarily select the relevant system stress intervals.

How many Intervals are Peak Intervals?

Figure 2 shows the load duration curve[20] for each Capacity Year[21] from 2015 to 2021. Figure 3 zooms in to the top 25 intervals of each Capacity Year. Figure 2 and Figure 3 show that the shape of the load duration curve differs between Capacity Years. For example, in 2017, 2019 and 2020, there are only a few very high load intervals, with several hundred MW difference in demand between the highest interval and the tenth highest interval. In other years the drop-off is not as steep, but in most years, the load drops off markedly somewhere between the 5th and 20th interval. This indicates that the current figure of around 12 intervals remains reasonable.

[20] Total Sent Out Generation. There was no load curtailment or lost load in these intervals.

[21] 8am 1 October through 7.59am the following 1 October.

Figure 2: Load Duration Curves for 2015-2021

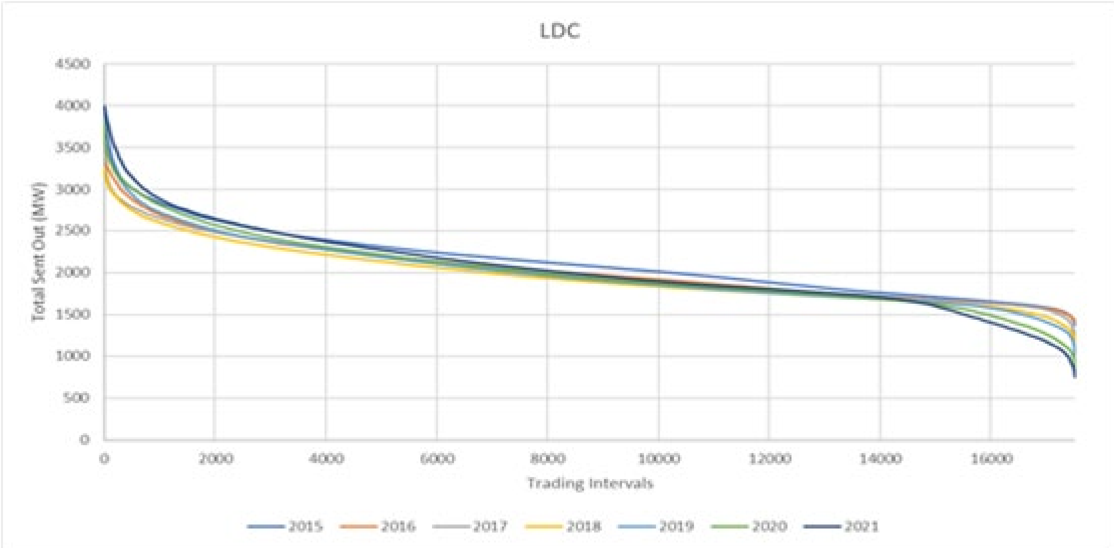
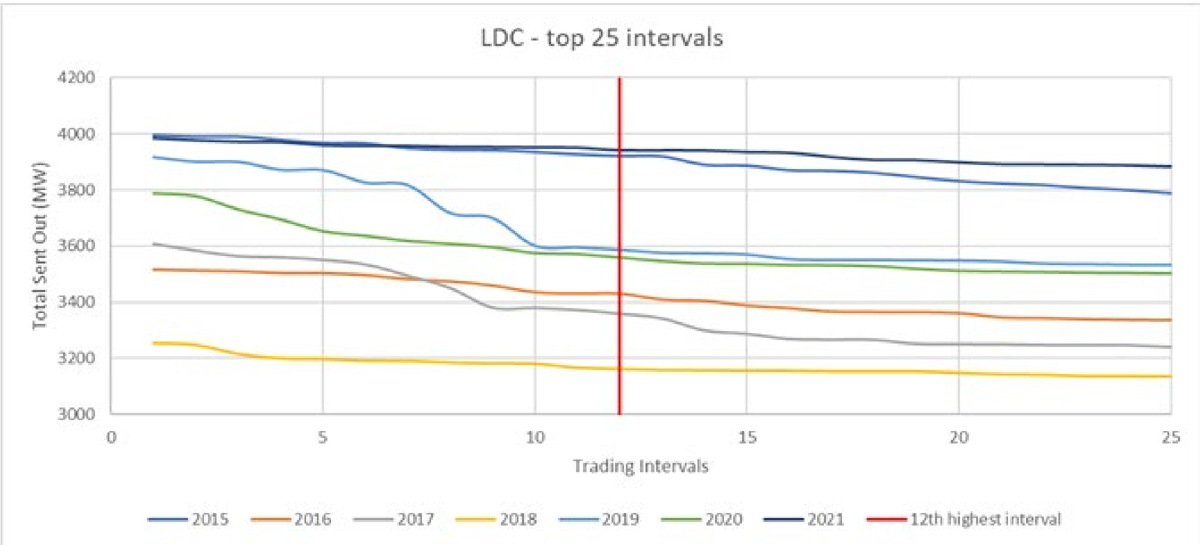


Figure 3: Load Duration Curves for 2015-2021 – top 25 Intervals



How Many Days are Peak Days?

Figure 4 shows on how many days the top 12 intervals fell on in each Capacity Year. Figure 5 shows the number of intervals on each of the relevant days.

In 2015, 2016, 2017 and 2020, the peak Trading Intervals fall only on two days. In other years, the highest demand periods are distributed over a wider range of days, especially in 2021 where they occur on six different days.

All peak intervals were experienced in the Hot Season except for one interval in 2018 (highlighted in red). 2018 had a mild summer, and the lowest peak load of any year in the sample.

Figure 4: Number of Days on which the Top 12 Demand Intervals Fall

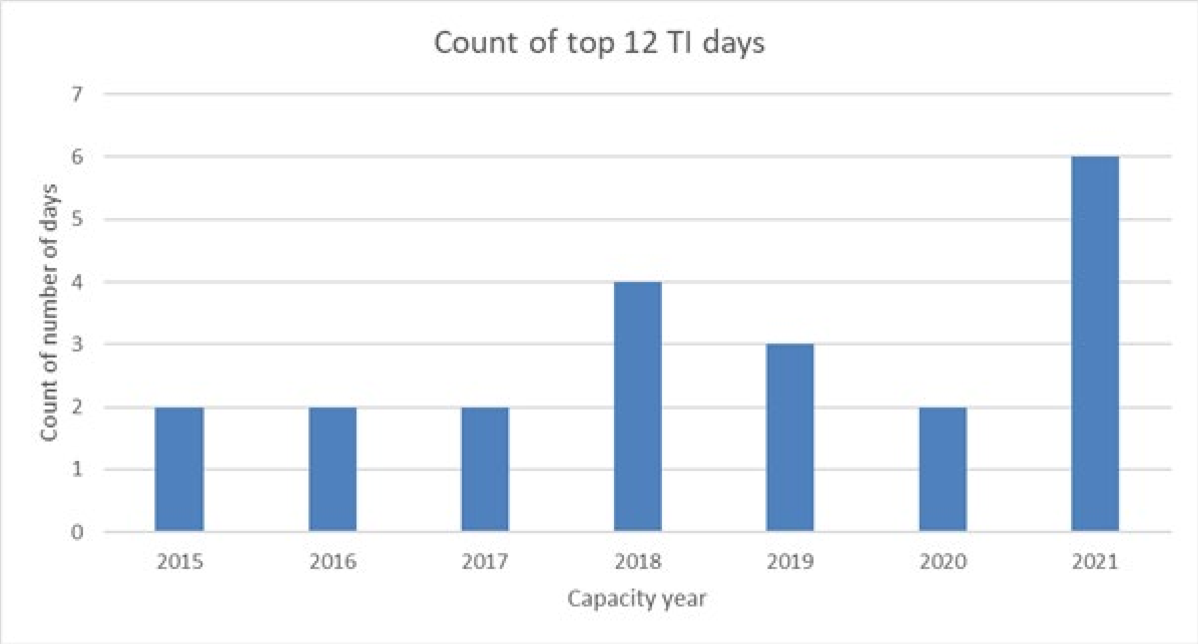
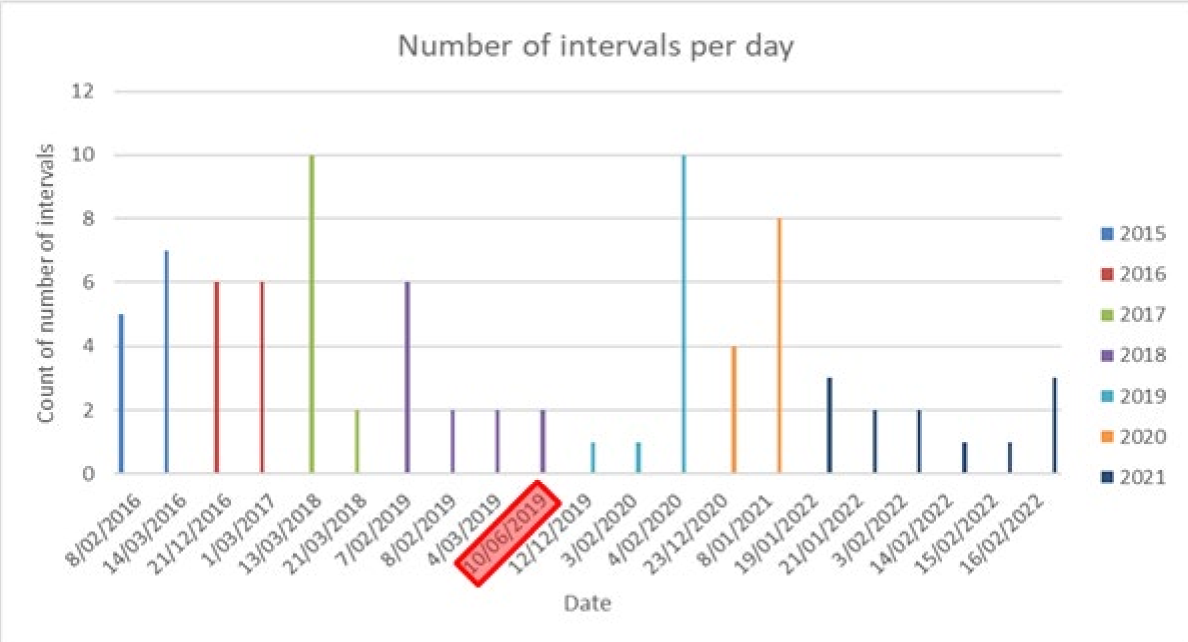


Figure 5: Number of Peak Intervals Falling on Each Day



The analysis indicates that the shape of the load on the peak demand days varies. For example:

- In Capacity Years 2017 and 2019, 10 of the 12 highest load intervals occurred on a single day;
- In 2018 and 2021, there were several days with similarly high levels of load; and
- In 2016 and 2020, some days had both morning and evening peaks, while in 2019 and 2021 none of the peak days had significant morning peaks.

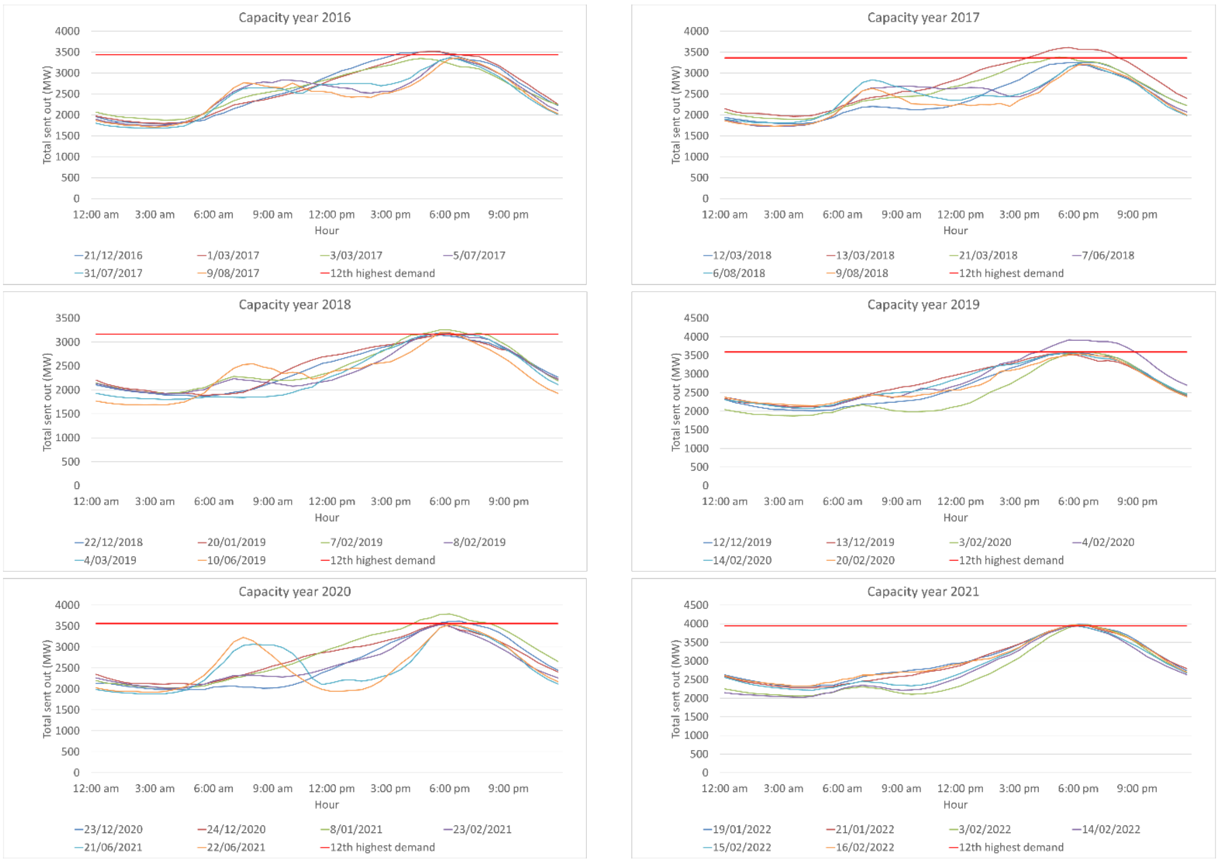
The current IRCR method would select only three intervals from the highest demand days, even if they have additional intervals with higher demand than intervals chosen from other days.

Selecting the IRCR intervals from a minimum of four days each year regardless of the load differential between those days would mean that the IRCR is based on time periods where there is no significant system stress.

MAC members expressed concern that reducing the number of the selected days will make it more difficult for consumers to manage their IRCR exposure. While EPWA recognises that reducing the minimum to one or two days would increase the difficulty for consumers to manage their IRCR exposure, it considers that three days would allow more effective incentive for response to the IRCR signal.

Figure 6 includes six charts showing the load on the six days with the highest peak demand for each Capacity Year from 2016 to 2021. The red line in each chart shows the load in the 12th highest interval for the year.

Figure 6: Load Profile on Peak Demand Days



Are Peak Intervals Always Contiguous?

Table 5 shows where the top 12 system demand intervals fall across the relevant days. Each row shows a time of day, each column is a particular high demand day, and there is a tick if one of the 12 highest demand intervals for the year fell at that time of the day. All intervals fall in the afternoon or evening, and form a contiguous block on each day, except for one day in Capacity Year 2018, where the load dips slightly in one interval before returning to a higher quantity. Participant behaviour in that interval is also indicative of their contribution to the RCR.

Table 5: Occurrence of Peak Intervals on Peak Days

Capacity Year	2015		2016		2017		2018				2019			2020		2021					
Day	1	2	1	2	1	2	1	2	3	4	1	2	3	1	2	1	2	3	4	5	6
3:30 pm			✓		✓																
4:00 pm		✓	✓	✓	✓								✓								
4:30 pm	✓	✓	✓	✓	✓		✓						✓		✓						
5:00 pm	✓	✓	✓	✓	✓	✓	✓						✓		✓						
5:30 pm	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓				✓	✓
6:00 pm	✓	✓	✓	✓	✓		✓	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓		✓
6:30 pm	✓	✓		✓	✓		✓					✓	✓	✓	✓	✓	✓	✓			✓
7:00 pm		✓			✓								✓	✓	✓						
7:30 pm					✓		✓						✓		✓						
8:00 pm					✓								✓		✓						
8:30 pm													✓								

Is the Whole Year Relevant?

In mild temperature years, with a relatively low summer peak demand, or in years where there is a single high demand event, it is possible that some of the top intervals may fall in winter, as is the case in 2018, the year with the lowest peak demand in the sample. However:

- these intervals do not represent stress events, and the demand is not reflective of a 1-in-10 year peak;
- the SWIS currently experiences extreme peak demand only in the summer period, therefore generation or consumption in the summer period is the most important factor. There is currently limited benefit in sending a signal for loads to reduce the peak load during winter; and
- focusing generation and load incentives on the Hot Season period would increase predictability for participants.

EPWA therefore proposes to retain the restriction on IRCR intervals to the December-March period. This restriction should be revisited if winter peak values start to approach the extremes seen in summer in a 1-in-10 peak year.

Proposed Interval Selection Methodology

The proposed IRCR interval selection methodology is as follows:

(1) identify the 12 intervals from the previous hot season (December-March) with the highest total sent out generation (SOG);

(2) identify the Trading Days on which those intervals fell;

(3) if fewer than three days are identified in step (2), identify the additional days in the summer season with the highest SOG outside the top 12 intervals to make a total of three days, rather than one or two days;

(4) for each identified day, select:

(a) the interval with the highest SOG;

(b) all other intervals that are in the top 12 intervals;

(c) all intervals between the intervals selected in steps (4)(a) and (4)(b); and

(d) If fewer than three intervals have been selected, select the next highest SOG intervals on either side of the selected intervals to make up to three intervals.

Table 6 shows the results of this method compared to the current IRCR intervals for Capacity Year 2017. The demand column is shaded to indicate the highest demand intervals in red. Examples for additional Capacity Years are shown in Appendix C.

Table 6: Capacity Year 2017 IRCR Intervals – Current vs Proposed

Date	Time	SOG (MW)	Proposed Intervals	Current Intervals
15/02/2018	5:00 pm	3172.2	✓	✓
15/02/2018	5:30 pm	3195.6		✓
15/02/2018	6:00 pm	3164.6		✓
12/03/2018	5:30 pm	3247.8	✓	✓
12/03/2018	6:00 pm	3251.5	✓	✓
12/03/2018	6:30 pm	3248.6	✓	✓
13/03/2018	2:30 pm	3252.7		
13/03/2018	3:00 pm	3300.3		
13/03/2018	3:30 pm	3380.7	✓	
13/03/2018	4:00 pm	3451.6	✓	
13/03/2018	4:30 pm	3536.1	✓	
13/03/2018	5:00 pm	3585.6	✓	✓
13/03/2018	5:30 pm	3609.5	✓	✓
13/03/2018	6:00 pm	3565.7	✓	✓
13/03/2018	6:30 pm	3561.2	✓	
13/03/2018	7:00 pm	3552.5	✓	
13/03/2018	7:30 pm	3496	✓	
13/03/2018	8:00 pm	3373.5	✓	
13/03/2018	8:30 pm	3266.7		
21/03/2018	4:00 pm	3267.3		
21/03/2018	4:30 pm	3343.6	✓	✓
21/03/2018	5:00 pm	3382.1	✓	✓
21/03/2018	5:30 pm	3360.2	✓	✓
21/03/2018	6:00 pm	3288.4		
21/03/2018	6:30 pm	3270.0		

The MAC supported this approach to selecting IRCR intervals for the peak capacity product.

Proposal B:

Retain current approach of using only intervals in the Hot Season (Trading Days from 1 December to 31 March) to set IRCR.

Amend the IRCR interval selection provisions to ensure that:

- all 12 highest demand intervals in the Hot Season are selected;
- intervals on a minimum of three days are selected; and
- where the peak intervals occurring on each day are not contiguous, the intervening intervals are selected.

The Coordinator's review of WEM effectiveness will include reviewing whether extreme demand events are forecast to occur outside the Hot Season.

Consultation Questions:

(2) Do stakeholders support the proposed interval selection methodology?

3.2.4 Temperature Dependence

The current IRCR method provides for different treatment of TDLs and NTDLs. To qualify as an NTDL, consumption during the 4 peak demand intervals in each of 9 previous months must have a median greater than 1 MWh and must be narrowly distributed around the median.

An NTDL receives a lower IRCR than an otherwise equivalent TDL, on the basis that it has relatively flat load, which has little variation between peak and off-peak periods. This could be seen as conceptually similar to the runway method for allocating Spinning Reserve, associating the 'first MW' of capacity with NTDLs, and the 'last MW' of capacity requirement to more variable loads. However:

- each MWh of usage at peak times has an equivalent contribution to the RCR;
- the types of loads that can qualify as NTDL are also likely to be the types of loads that can adjust their consumption during IRCR intervals, meaning that such loads already have an opportunity to manage their exposure to capacity charges;
- the multiplier reduces the incentive for a participant to make its consumption flexibility available to market dispatch by participating as a DSP; and
- the NTDL/TDL process is non-trivial for participants and AEMO to manage.

Further, as discussed in section 3.3, flat loads do not contribute to the need for flexible capacity, so the proposed IRCR approach for flexible capacity will inherently allocate low (or no) cost to a load with flat consumption profile.

The MAC and RCMRWG supported removing the distortionary effect of TDLs and NTDLs on cost recovery, to level out the treatment of large and small loads.

Proposal C:

Remove TDL/NTDL multipliers from the IRCR process.

Consultation Questions:
(3) Do stakeholders support the removal of TDL and NTDL multipliers?

3.2.5 Treatment of New Loads

Loads have different characteristics to generators:

- their demand profile is more likely to change over time;
- their demand profile is more likely to be volatile;
- there are many more of them;
- they are likely to commission frequently at all times of the year; and
- they are likely to change ownership (or responsible party) more frequently, including during the Capacity Year.

This means that a participant's IRCR must be able to change throughout the year, to account for commissioning and ownership changes. For existing loads, switches can be accounted for either by recalculating the IRCR each day, or by multiplying the demand by the proportion of the month (or week) that each participant was responsible for the load.

However, when a load first commissions or installs TOU metering, there will not be a record of its load during the selected IRCR intervals in the previous Capacity Year. As a proxy, the current IRCR methodology uses the demand of the new load during the four peak intervals of month n-3. These intervals are unlikely to be reflective of actual system stress, particularly where month n-3 falls in the winter or spring, and in those months will underestimate Hot Season demand for most loads.

Alternatively, the IRCR process could use:

- average load across all meters;
- historical maximum consumption or maximum allowed network offtake as held in standing data; or
- historical maximum load.

Using average demand of other loads would not appropriately account for the different sizes of load. Using historical maximum consumption or allowed offtake would overestimate the contribution of many loads if that consumption is not correlated with the overall demand profile.

Instead of using the median demand in the four peak intervals of month n-3, EPWA proposes to use the maximum of the median demand in the four peak intervals of any prior month.

The notional wholesale meter would continue to have a 'new' component based on non-interval meter growth, but the median notional wholesale meter would be based on load in the relevant hot season intervals.

Proposal D:
Calculate IRCR on a daily basis.

Set representative load for new meters based on the maximum of the median demand in the four peak intervals of any prior calendar month.

Consultation Questions:

(4) Do stakeholders support the changes to the treatment of new loads?

(5) The settlement cycle is weekly, not monthly. Do stakeholders see any issues with the use of monthly peaks where IRCR is calculated daily?

3.3 IRCR for Flexible Capacity

The cost of procuring flexible capacity will be recovered from Market Participants, and the recovery method should be in accordance with the principles set out in section 3.1.

Recovery is only necessary where there is additional cost over and above the cost of procuring peak capacity. In situations where there is no price premium for flexible capacity, all capacity costs will be recovered through the peak product cost recovery mechanism. The flexible IRCR calculation is therefore only relevant where additional expenditure is required to attract flexible capacity.

As noted in section 2.2.2, Part 1, the RCR for flexible capacity will be set based on AEMO's forecast of the largest expected system ramp in the relevant Capacity Year. This means that the key driver of the RCR for flexible capacity is the shape of the load, and the extent to which there is a rapid and sustained change in intra-day demand.

3.3.1 Options for Setting Flexible IRCR

Options

There are two main options for determining IRCR for the flexible capacity product:

(1) Use the same calculation as used for peak IRCR, but scaled to the different RCR. That is:

FlexIRCR = PeakIRCR * (Flexible RCR / Peak RCR)

Under this approach, participants would pay the same proportion of costs for both peak and flexible capacity.

(2) Calculate flexible IRCR based on the contribution to the flexible capacity RCR. Under this approach, the shape of each load would determine its flexible IRCR, i.e. a load's historical contribution to periods of steep ramping would drive its IRCR:

(a) flat loads (which do not contribute to the RCR) would have a low or zero flexible IRCR;

(b) loads which decrease consumption during high ramp periods would also have a low or zero flexible IRCR; and

(c) loads which increase consumption during high ramp periods would have a relatively high flexible IRCR.

Assessing the Options

Table 7 provides an assessment of each identified option for setting the flexible IRCR against the policy goals.

Table 7: Qualitative Comparison of Flexible IRCR Approaches

Goal	1. Peak IRCR	2. Contribution to High Ramp Periods
Capacity payments fully recovered from consumers	●	●
Allocates costs based on contribution to the RCR	○	●
Provides a signal to amend electricity use in a way that reduces the RCR	○	●
Allows costs to be allocated to new loads added during a Capacity Year	●	●
Simple, cost effective, and easy to understand	●	◕
Aligns with CRC methodology	◔	◕
Minimises year to year volatility	◑	◑
Can be replicated by potential investors and other stakeholders	●	●
Is predictable so it incentivises effective load management during system stress events	●	●

Option 1 would be simple to implement but would not provide an incentive to participants to reduce their contribution to the evening ramp.

Option 2 would be more complex to implement, but would provide that incentive.

Both options allow capacity payments to be fully recovered from consumers, and can account for new loads being added during a Capacity Year.

The RCR is set according to the Planning Criterion. Option 2 allocates costs in alignment with consumer contribution to the RCR but Option 1 does not.

While Option 1 is very simple, option 2 is not much more complicated. Both methods can be replicated by external participants using publicly available data, and can be predicted in advance with some confidence.

Option 2's approach is better aligned with the CRC allocation approach for flexible capacity, as it relates to performance during key periods. Option 1 would assign IRCR based on consumption during peak periods, which does not relate to the criteria used for flexible CRC allocation.

With a single year lookback, both methods are likely to have some volatility, but only insofar as consumption profiles are volatile.

The MAC considered that Option 2 best complements the way the flexible RCR is set.

Proposal E:

Set participant IRCR for flexible capacity based on the load shape in high ramp periods.

Consultation Questions:

(6) Do stakeholders support determining flexible IRCR based on consumer contribution to the ramp during high ramp periods?

3.3.2 Characteristics of High Ramp Days

When do High Ramp Periods Occur?

In the summer season, load is generally high throughout the day, as air-conditioning load runs continuously. Outside the summer period, load is lower in the daytime and behind the meter solar declines earlier, resulting in a steeper ramp in the afternoon and evening, albeit to a lower peak.

Figure 7 shows how many of the top four high ramp days fall in each month of the year. In all Capacity Years from 2015 to 2021, all the highest ramps occur between June and September, i.e. mainly in winter.

Figure 7: Timing of High Ramp Days

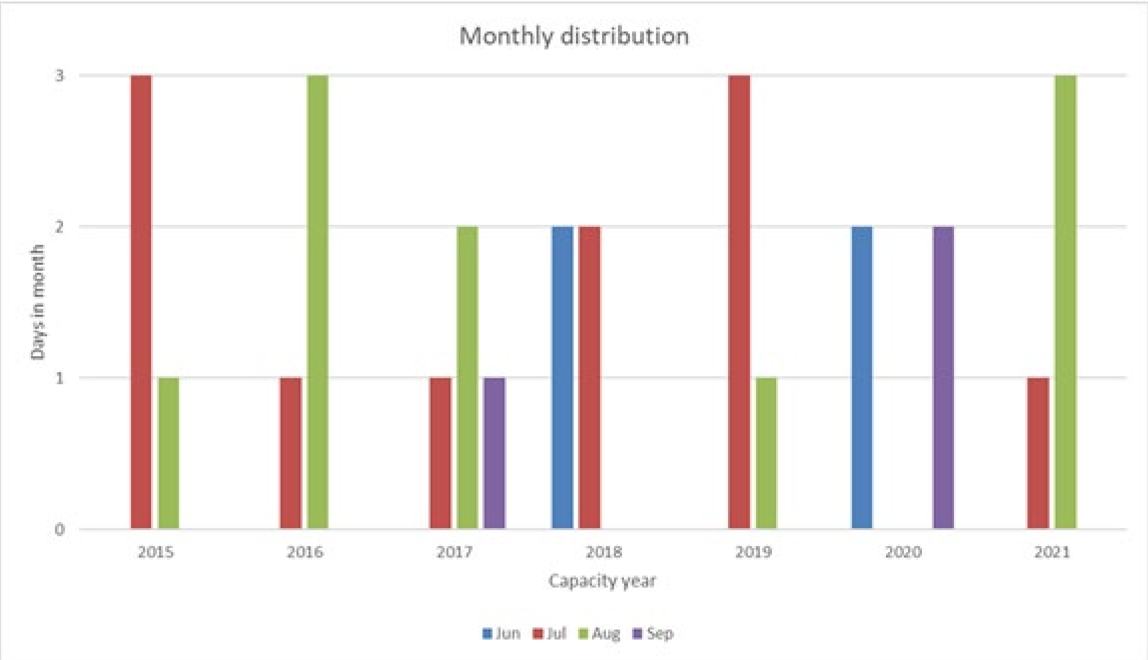


Figure 8 shows the distribution of maximum daily ramps for each Capacity Year from 2015 to 2021, and Figure 9 zooms in on the top 20 days of each Capacity Year.

Figure 8: Maximum 4-Hour Ramp Rate Distribution

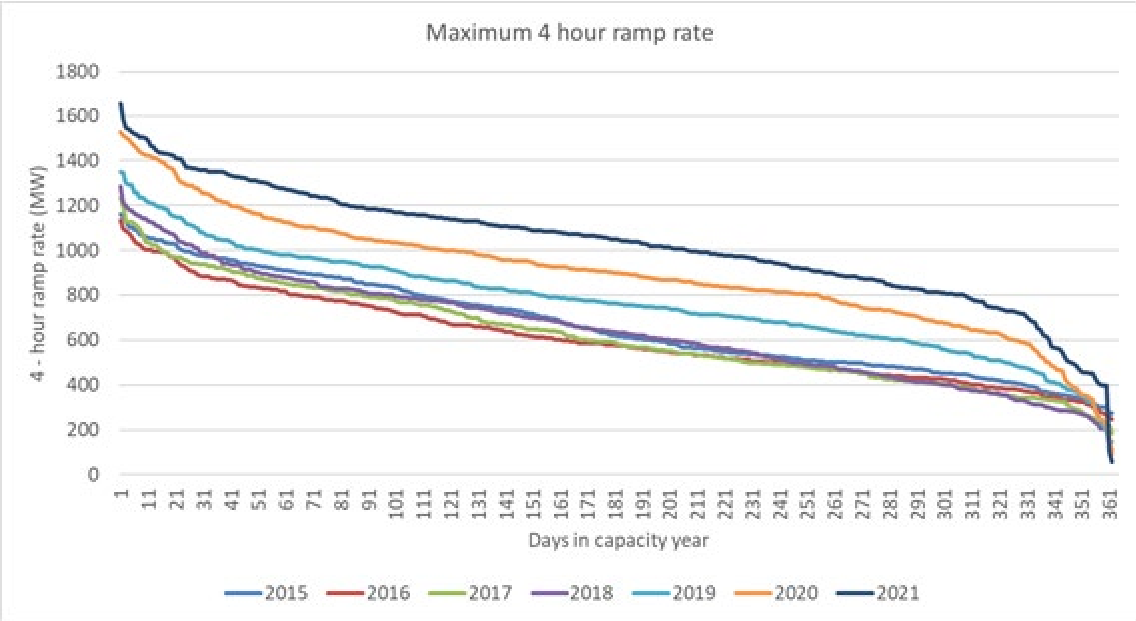
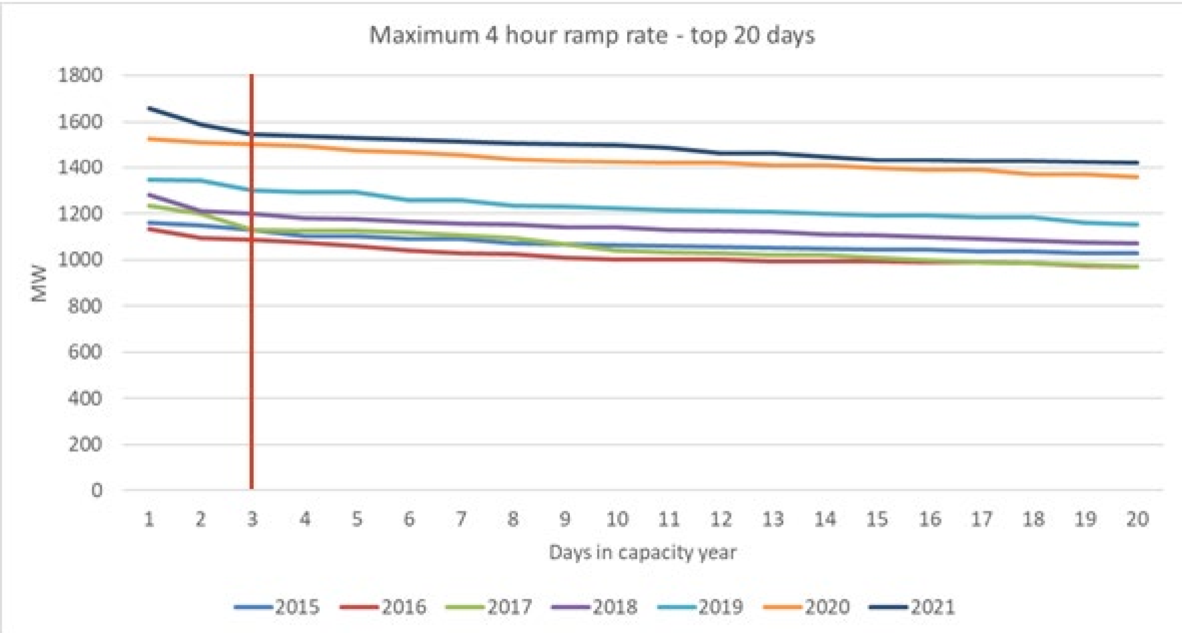


Figure 9: Maximum 4-Hour Ramp Rate Distribution – Top 20 Days



In some Capacity Years (e.g. 2017, 2018 and 2021), the highest daily ramp day is significantly steeper than on other days, while in other years, the maximum daily ramp falls off more slowly.

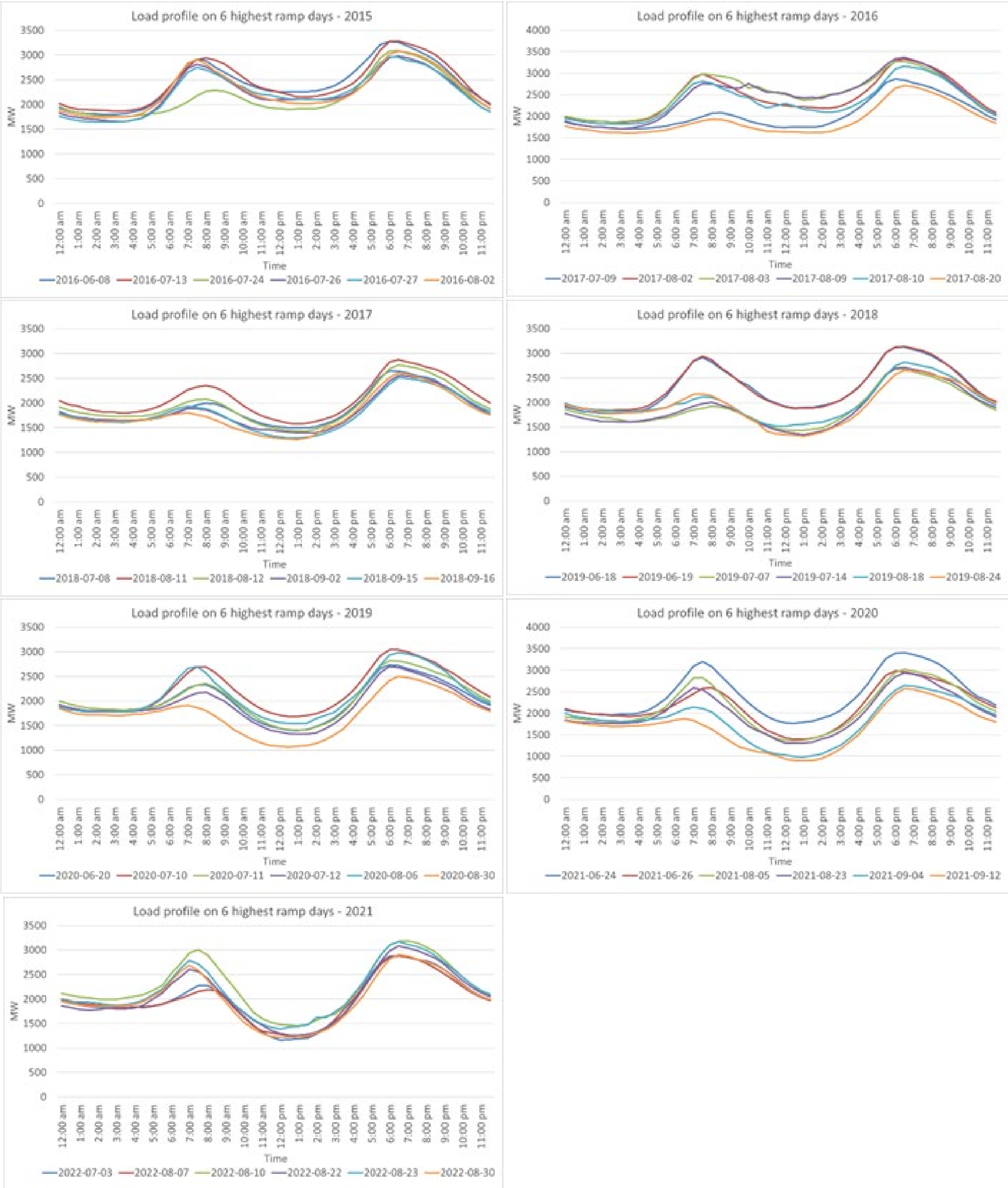
While the flexible RCR will be set based on the highest single ramp expected in the year, the IRCR methodology will look backwards. Using a single day would make it difficult for consumers to manage their exposure to the flexible IRCR, so it is reasonable to use more than one day.

In line with the peak IRCR calculation, EPWA proposes to use the three days with the highest ramp.

How Long Does a High Ramp Period Last?

Figure 10 shows the load shape for selected high ramp days. The time period from the end of the midday trough through to the daily peak spans generally around 4 hours, though it can be longer or shorter depending on the day.

Figure 10: Load Profile on Top 6 Highest Ramp Days



What Time of Day do High Ramp Periods Occur?

Table 8 shows when the high ramp period occurred on the highest ramp days. Until Capacity Year 2016, some of the highest 4-hour ramps were observed in the morning. Since 2017, all of the highest ramps occur in the lead up to the evening peak. This pattern is expected to continue with increasing penetration of generation from DPV.

It does not appear necessary to restrict the steepest ramp to a particular time of day.

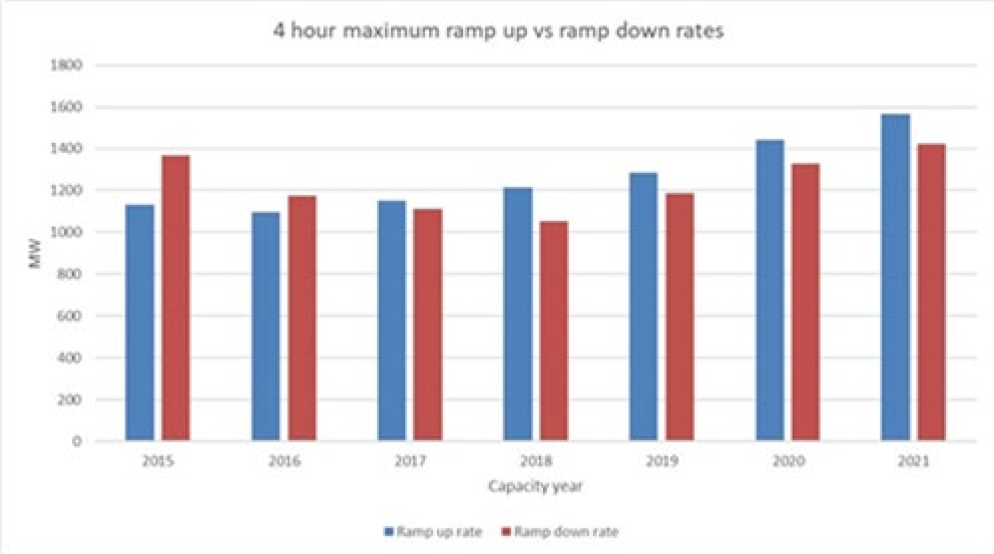
Table 8: Times of day for High Ramp Periods

	Hours Making up the Highest Ramp Requirement						
Time of the day/Capacity year	2015	2016	2017	2018	2019	2020	2021
3:30 am	2	1					
4:00 am	2	1					
4:30 am	2	1					
5:00 am	2	1					
5:30 am	2	1					
6:00 am	2	1					
6:30 am	2	1					
7:00 am	2	1					
7:30 am	2	1					
2:00 pm	1	1	1	4	3	2	2
2:30 pm	2	3	4	4	4	4	4
3:00 pm	2	3	4	4	4	4	4
3:30 pm	2	3	4	4	4	4	4
4:00 pm	2	3	4	4	4	4	4
4:30 pm	2	3	4	4	4	4	4
5:00 pm	2	3	4	4	4	4	4
5:30 pm	2	3	4	4	4	4	4
6:00 pm	2	3	4	4	4	4	4
6:30 pm	1	2	3		1	2	2

Is Downward Ramp Relevant?

Figure 11 shows the size of the largest four-hour upward and downward ramps for each Capacity Year from 2015 to 2021.

Figure 11: Maximum Ramp Up vs Ramp Down Comparison



In Capacity Years 2015 and 2016, the maximum downward ramp was higher than the maximum upward ramp. Since 2017, the ramp up requirement has been higher, tracking with increased penetration of distributed generation.

EPWA proposes to use the ramp up requirement as the relevant metric for the flexible capacity product, because:

- the ramp up requirement is expected to remain higher than the ramp down requirement;
- facilities which can ramp up quickly can also ramp down quickly; and
- ramping down in the morning period can be managed by curtailing registered solar PV facilities (those which are dispatched by the Dispatch Algorithm), while all solar facilities are naturally ramping down through the afternoon ramp and are not available to increase output in the evening.

Proposed Method for Flexible Capacity IRCR

The proposed flexible capacity IRCR selection methodology is as follows:

(1) For each Trading Interval in the previous Capacity Year, find the difference between the operational load at the end of the Trading Interval and the load at the end of the Trading Interval four hours prior.

(2) Select the three Trading Days with the highest four-hour ramp value calculated under step (1).

(3) For each Trading Day selected under step (2):

  (a) select the Trading Interval with the largest value calculated under step (1); and

  (b) select all Trading Intervals in the previous four hours.

(4) For each participant load portfolio:

  (a) calculate the portfolio ramp contribution for each day selected in step (2), as the difference between consumption at the start of the earliest selected Trading Interval and the end of the latest selected Trading Interval; and

(b) calculate the portfolio annual ramp contribution as the mean of the portfolio ramp contributions determined in step (4)(a).

(5) Calculate scaling factor R as the RCR for flexible capacity divided by the sum of all portfolio annual ramp contributions.

(6) For each participant load portfolio, set the flexible IRCR as the portfolio annual ramp contribution multiplied by the scaling factor.

The flexible IRCR will be recalculated daily to account for switching and new loads.

This approach aligns with the approach used for the peak IRCR, while reflecting the different nature of the flexible capacity requirement.

Appendix C shows which intervals would be selected under this method for each year from 2015 to 2021.

Proposal F:

Set IRCR for flexible capacity based on the three days with the highest four-hour upwards ramp at any time during the year.

Require AEMO to publish the forecast ramp so that consumers can monitor and respond to the cost signal.

Consultation Questions:

(7) Do stakeholders support the proposed interval selection method?

(8) Do stakeholders agree that it is necessary for AEMO to publish the forecast ramp?

4. Demand Side Programmes

4.1 Introduction

DSPs are a mechanism for loads to participate in the RCM. The current design is geared to large industrial loads and is not appropriate for the aggregations of smaller loads that are expected to progressively enter and exit the market. There is also an opportunity to align with the changes to CRC for intermittent generators and to the IRCR method.

Chapter 4 discusses the approaches to CRC allocation and dispatch for DSPs. Consequential changes to the testing, outages, and refund regimes are covered in Chapter 5.

4.2 DSP CRC

CRC allocation for DSPs needs to be performed ahead of time (as it is for generators) rather than being assessed during the Capacity Year, so that it can be accounted for during the capacity certification process.

EPWA is seeking an approach to assessing DSPs' CRC that:

- ensures that the system reliability objective is met;
- adequately assesses facilities' contribution to system reliability;
- minimises year-to-year volatility for investors;
- is simple and easy to understand;
- ideally can be replicated by potential investors and other stakeholders; and
- aligns with CRC methodology for intermittent generators.

4.2.1 Current Approach

Currently each DSP is allocated CRC based on its "Relevant Demand", which is the lower of:

- the aggregate IRCRs of its Associated Loads; and
- its historical 95% POE consumption during the 200 intervals with the highest generation.

Participants can request that intervals where the load was out for maintenance are excluded from the calculation by submitting a "consumption deviation application".

The 95% POE consumption limb of the Relevant Demand calculation always sets the Relevant Demand. As a result, this method favours a flat load profile, significantly muting the incentive for loads with a variable profile to participate in the market, as noted in Rule Change Proposal RC_2019_01. Participants with such flexible load can reduce their IRCR exposure by managing their own load behind the meter and have limited incentive to include it in central market scheduling.

This approach also differs from the approach used to set IRCR and intermittent generation.

4.2.2 Alternative Options for DSP CRC Allocation

EPWA identified three options for allocating DSP CRC that align with the selected IRCR and intermittent generation CRC methods:

(1) using an ELCC approach (either by fleet or individually);

(2) basing the CRC on load in historical IRCR intervals; or

(3) having the DSP proponent nominate a CRC, accompanied by evidence that there will be sufficient load associated with the programme to deliver that CRC at expected dispatch times.

Option 1: ELCC

The overall contribution of registered DSPs to system reliability could be assessed in the same way as intermittent generators:

(1) using historical load, find the load at which EUE is at the Planning Criterion target level;

- adjust the historical data for DER penetration and any load curtailment (e.g. DSP dispatch, unserved energy, SRC or NCESS dispatch), and historical intermittent fleet output (adjusted for involuntary curtailment);

(2) for each DSP, identify available curtailment in each interval in the previous Capacity Year.

(3) adjust the historical load trace to subtract available DSP curtailment.

(4) increase load until EUE is the same as it was in step (1).

The added load in step (4) is then the DSP ELCC.

Alternatively, a DSP fleet ELCC could be allocated to individual DSPs based on their available curtailment in the same intervals used for IRCR.

The ELCC approach (whether at fleet or facility level) is less appropriate for DSPs than for supply side facilities, as loads have different operating constraints to generators. In particular, while intermittent generators generally seek to output as much energy as possible, the consumption at each load is driven by a range of factors, none of which involve consuming as much as possible.

Option 1 also relies on historical consumption being a good indicator of future consumption.

Option 2: Determine DSP CRC Based on IRCR Intervals

DSP CRC levels could be allocated based on median consumption in the same intervals used to determine IRCR.

This approach would mean a better balance between a participant’s incentives to minimise IRCR (by having low load at times of system stress) and maximise DSP CRC (by having high load at times of system stress that can then be curtailed).

Option 2 would not account for synergies or disparities between the load profiles of different DSPs.

Option 2 is most suited where historical consumption is a reliable indicator of future consumption – such as for large industrial loads with a relatively flat consumption profile. Where a DSP’s Associated Loads are likely to change from year-to-year, this method is open to potential gaming by selecting loads based on their performance in the previous year only.

Option 3: Participant Nominated CRC

Participants could be made responsible for determining the quantity of reduction by having DSP proponents nominate a performance level for the DSP – the MW of load response it commits to provide, when called.

Historical load data would not be used to directly set the CRC level, but the participant would need to show evidence that it will have sufficient associated load to deliver the nominated reduction. This would be confirmed through Reserve Capacity Testing during the relevant Capacity Year.

The DSP would need to pay immediate refunds upon failure to provide the nominated level when dispatched or tested, to provide incentive to ensure the programme can deliver the nominated reduction.

Option 3 would be appropriate for aggregations of multiple small loads, particularly where the Associated Loads are likely to change from year to year, and would allow programme operators more leeway to manage their fleet of Associated Loads over time.

Assessing the Options

Table 9 provides an assessment of each identified option for allocating CRC to DSPs against the policy goals.

Table 9: Qualitative Comparison of Approaches to Allocate CRC to DSPs

Goal	1. ELCC	2. IRCR Intervals	3. Nomination
Ensures that the system reliability objective is met	◕	◕	●
Adequately assesses facilities' contribution to system reliability	◕	◕	●
Minimises year-to-year volatility for investors	◑	◕	●
Is simple and easy to understand	◑	◕	●
Ideally can be replicated by potential investors and other stakeholders	◑	●	●
Aligns with CRC methodology for intermittent generators	◕	◕	◑

All options would ensure system reliability is met, although options 1 and 2 would do that only if historic data is a good indicator of future performance.

Options 1 and 2 could overestimate the quantity of reduction that is available from a DSP if future load is not correlated with past load, but would better align DSP incentives with those provided by IRCR and intermittent CRC processes.

Option 3 gives participants control over changes in CRC from year to year.

Option 3 is the easiest to understand and replicate, while option 1 is the most complex and difficult to replicate.

Options 1 and 2 are closer to the method to be used for intermittent generation CRC, while option 3 is more like the approach used for scheduled facilities.

All options would rebalance the incentive for participants to make demand flexibility available for dispatch via a DSP rather than just controlling it themselves via IRCR.

4.2.3 Proposed Method for DSP CRC

EPWA considers that the different characteristics of different loads mean that it is appropriate to use different methods for different types of DSPs. In particular:

- For DSPs with large industrial loads, the specific NMIs involved will be clearly identifiable at the time of certification, several years before the actual delivery of the capacity service, and will not change from year to year. These DSPs can be certified based on historical demand data.
- For DSPs made up of many aggregated loads, the specific NMIs involved may not be identified at the time of certification, and only identified closer to the start of the Capacity Year.

This approach allows historical data to be used where it can be relied on for DSPs with large industrial loads, while putting the onus on aggregators of smaller loads to “overfill the programme” to provide evidence that they have sufficient load to curtail when needed.

RCMRWG participants expressed concern about the potential cost of having two methods to allocate CRC to DSPs, and that there may not be a sizable pool of potential flexible loads to justify this cost.

EPWA considers that the effort is substantially the same for both approaches, with the same outage, testing and refund arrangements. The WEM Rules already contemplate Associated Loads changing during the year, and systems to add and subtract Associated Loads to and from DSPs are already required.

If the IRCR is to be used for DSP certification (Option 1), it will have already have been calculated, and the participant nomination (Option 2) allows the proponent to manage the risk of uncertain output. Given the future importance of demand side response from aggregated loads, the RCM needs to change to reduce barriers to using this important resource.

Proposal G:

Where a DSP has:

- the same Associated Loads that it had in the previous year, assign CRC based on IRCR of the Associated Loads less the minimum load requirement of the Associated Loads; and
- different Associated Loads from the previous year, assign CRC based on a value nominated by the Market Participant.

Consultation Questions:

(9) Do stakeholders support the proposed DSP CRC allocation method?

4.2.4 Consumption Deviation Applications

Historical load (both system wide and for each Associated Load) must be adjusted to remove the effects of AEMO dispatch, just as intermittent facility output data is adjusted to remove the effects of involuntary curtailment.

The current DSP CRC allocation approach allows participants to nominate specific intervals as being affected by an AEMO instruction, or by maintenance, and to have those intervals excluded from the CRC assessment. This is roughly equivalent to how generation facilities are assigned a Reserve Capacity Obligation Quantity (RCOQ) of zero when on an approved planned outage, but without the same outage approval process.

Excluding these maintenance intervals from consideration is inconsistent with the treatment of other facilities. Planned outages of schedulable generation are not approved to occur at times of expected system stress, and intermittent generation is assessed on all intervals. DSP Associated Loads should also be measured on their actual consumption during periods of system stress.

EPWA proposes to remove consumption deviation applications for DSPs, and instead adjust consumption records where necessary using AEMO's records of DSP dispatch (including testing).

Proposal H:

Remove Consumption Deviation Applications (CDAs) from the assessment of DSP CRC.

Consultation Questions:

(10) Do stakeholders support the removal of CDAs?

4.2.5 Including Hybrid Facilities in DSPs

Some facilities may have load co-located with generation or storage. A connection point will only be eligible to be an Associated Load of a DSP if its generation or storage is smaller than the de-minimis registration threshold under clause 2.29.4 and 2.29.4A.

If a participant has both load and storage behind a single connection, and the storage is not required to be registered, the site could choose to be an Associated Load of a DSP. If the storage was of a size required to register, the site could participate in the RCM as a Capability Class 2 facility.

Where a participant has both load and intermittent generation behind a single connection, the magnitude of potential injection would determine whether the site could participate in the RCM as part of a DSP or whether it would need to be registered as a Capability Class 3 facility.

Rules will be needed to ensure that a Capability Class 2 facility with collocated load and storage cannot self-discharge its storage so as to reduce its IRCR exposure while also receiving Capacity Credits for that capability. This will be addressed through EPWA's Demand Side Response Review.

Proposal I:

Allow sites with collocated load and generation or storage to be Associated Loads of a DSP.

Consultation Questions:

(11) Do stakeholders agree that sites with generation or storage should be able to be part of a DSP?

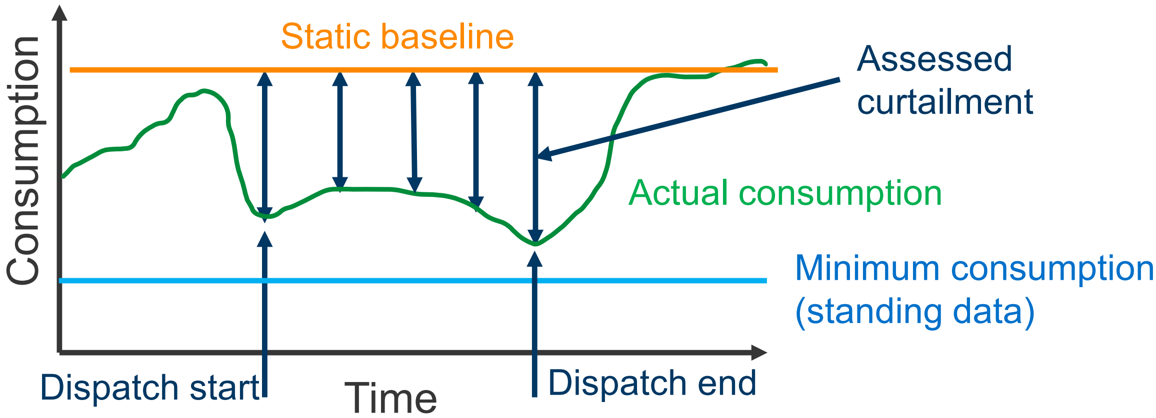
4.3 DSP Dispatch

DSPs are scheduled and dispatched differently from generation facilities. Their nature as a last-resort reserve capacity supplier means that they are very seldom dispatched, and their provision of load reduction means that their contribution must be measured against a counterfactual of what they would have consumed if they had not been dispatched.

DSPs can currently be dispatched for up to 200 hours each year.

Under current arrangements, DSPs are dispatched against a static baseline - the Relevant Demand discussed in section 4.2.1. Figure 12 shows an example of this measurement during a period that the DSP has been dispatched.

Figure 12: DSP Dispatch with a Static Baseline



The Relevant Demand used for dispatch is calculated based on demand in the previous Capacity Year, and is uniform for all Trading Intervals, changing only where a DSP's Associated Loads change.

This approach can accurately represent the contribution of loads with a relatively flat consumption profile over several years, where the static baseline accurately reflects the counterfactual consumption.

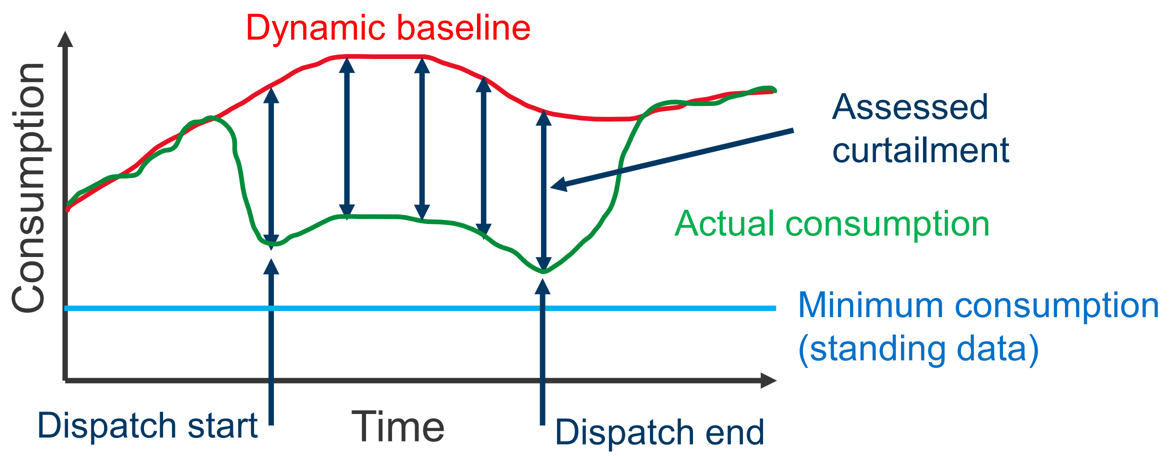
However, for loads with variable consumption patterns, a static baseline can under- or overstate the counterfactual consumption during likely times of dispatch. Both under- or overstatement of the counterfactual consumption are problematic:

- if the counterfactual load is overstated, then DSP dispatch will not deliver the expected reduction in load, which increases the risk to system reliability; and

- if the counterfactual load is understated, then system security is not at risk, but the DSP will deliver more reduction than required or requested, meaning load will have been unnecessarily curtailed.

A dynamic baseline that can vary from Trading Interval to Trading Interval can better reflect the contribution of load with a variable consumption profile. Figure 13 shows an example of a dynamic baseline.

Figure 13: DSP Dispatch with a Dynamic Baseline



A dynamic baseline more accurately reflects the actual curtailment delivered by the DSP compared to its level if not called. A dynamic baseline also allows better forecasting of the actual response expected from dispatched DSPs, which allows more reliable operation of the power system.

Under both static and dynamic baselines, each DSP has a specified minimum load below which it cannot be dispatched. Dispatch is also restricted to the number of Capacity Credits.

Some RCMRWG participants raised concerns about potential for gaming of a dynamic baseline. For example, if the baseline were set by interpolating between consumption immediately before and after the dispatch period, a DSP could artificially increase its consumption in those periods to increase its baseline.

EPWA has not yet considered any specific forms of dynamic baseline, but considers that a robust dynamic baseline could be set based on consumption on a range of previous similar days, rather than using periods after a participant knew the DSP would be dispatched.

The MAC generally supported a move to dynamic baselines for DSP dispatch. The MAC discussed potential for DSP proponents to nominate either a static or dynamic baseline but agreed that the additional complexity and cost was not warranted. One member considered that a static baseline was preferable because it meant that a load was dispatched against the same value on which its IRCR was calculated.

RCMRWG discussions on DSP dispatch arrangements raised the minimum availability of 200 hours per year as a barrier to participation for some loads which could curtail but are concerned about the impact on their operations.

Proposal J:

Adopt a dynamic baseline to measure DSP dispatch performance against.

Continue to assess the detailed dynamic baseline methodology.

Consider reducing the number of hours that DSPs can be dispatched.

Consultation Questions:

(12) Do stakeholders agree that measurement against a dynamic baseline would better reflect the actual contribution of DSPs at times of system stress?

(13) Would reducing the 200 hours that DSPs can be dispatched for in a year meet better the WEM objectives and, if so, what would be a more appropriate number of hours?

5. Other Aspects of the RCM

The scope of the RCM Review includes identifying changes to supporting processes needed to accommodate design changes in the RCM as a whole.

Changes to the testing, outages and refund regimes are needed to incorporate the new flexible capacity product, to accommodate changes to DSP arrangements and to amend the distribution of Capacity Rebates. No changes are required outside these areas.

5.1 Testing

The Reserve Capacity testing regime ensures that facilities holding Capacity Credits can effectively deliver the capacity that they are paid to provide.

5.1.1 Current Approach

The current capacity testing regime tests the ability of a facility to reach its maximum certified output level twice per year – once between October and March, and again between April and September.

A facility can pass during a scheduled test or by observation, if it happens to achieve its required level in the normal course of market operations. A facility gets two chances to pass a scheduled test – its Capacity Credits are reduced to the maximum level achieved if it fails both.

DSPs are treated slightly differently:

- A DSP must undergo an annual Reserve Capacity Test (clause 4.25.1(c)) between October and March to show that it can deliver a level of reduction from its static baseline equal to its assigned Capacity Credits for two Trading Intervals.
  - A DSP gets two chances to pass this test – if it fails twice, the DSPs Capacity Credits are reduced to the level of reduction achieved, and it must refund any capacity payments relating to the non-performing capacity;
- A DSP must undergo an annual verification test (clause 4.25A) in October/November to show that it can deliver a level of reduction from its static baseline of at least 10% of its assigned Capacity Credits for at least one Trading Interval.
  - A DSPs Capacity Credits will be reduced to zero upon failing the test, until the test is repeated, and will be reduced to zero for the year if the test is failed twice.

5.1.2 Required Changes

Flexible Capacity

Current capacity testing focuses on the ability to deliver energy or curtail withdrawal. Flexible capacity must be able to deliver its capacity quickly and at short notice.

Capacity tests for facilities holding flexible capacity credits need to include testing that the facility can:

- reach its certified output quantity from a ‘cold’ state at its certified maximum ramp rate; and

- start, stop, and restart within its certified timings.

Disruption to Market Participant operations will be minimised if these aspects can be tested at the same time as peak capacity testing or by observation, when a facility demonstrates its capability outside a scheduled test.

When scheduling tests, the capabilities should ideally be tested at a point in the Capacity Year before they are likely to be needed, but not so far before when system conditions are considerably different.

If a facility fails a scheduled test twice, its flexible capacity credits will be reduced to its maximum level of performance. If its performance does not meet the minimum requirements for flexible capacity (see section 2.4.4) its flexible capacity credits will be reduced to zero. A facility will retain its peak capacity credits as long as it passes that part of its capacity testing, and will be paid at the peak capacity price for any capacity that provides the peak capacity product.

Proposal K:

Require facilities holding flexible capacity credits to be tested for start, stop, restart, and minimum running times; ramp capability; and minimum stable loading level.

Allow facilities to pass flexible capacity tests by observation.

Require AEMO to schedule tests of flexible capacity characteristics to coincide with tests for peak capacity.

Consultation Questions:

(14) Do stakeholders see any other aspects of flexible capacity that should be included in the testing regime?

(15) Do stakeholders agree that flexible characteristics can be tested by observation?

(16) Should flexible capacity tests be scheduled at the same time as peak capacity tests?

Testing DSPs

DSPs are currently tested against a static baseline. With a dynamic baseline, testing needs to be conducted:

- against the new baseline, calculated from similar (but non-curtailed) intervals in recent historical data; and
- at times which are representative of conditions under which DSPs are likely to be dispatched, so that the dynamic baseline is as close as possible to what it would be in times of system stress.

Currently, the second test for DSPs requires only that it decrease output by 10% of its Capacity Credits. This is different from the treatment of other facilities that must fully demonstrate their capability twice in each Capacity Year.

DSPs that fail two tests currently have no incentive to restore their capability to meet their original level of Capacity Credits for rest of the Capacity Year. Instead of treating a test failure as enduring unavailability of capacity, treating it in a similar manner as the start of a forced outage (meaning that the participant would incur refunds until it passed a retest) would provide incentive for participants to remedy the unavailability. Participants could still choose to voluntarily surrender Capacity Credits if they expected to be unable to remedy the situation. As currently, they would also refund any capacity payments associated with the surrendered Capacity Credits.

Proposal L:

Adjust Reserve Capacity Testing for DSPs to reflect a shift to a dynamic dispatch baseline.

Require AEMO to consider the expected baseline when scheduling DSP tests.

Treat a failed test as the beginning of a Forced Outage, rather than a permanent reduction of Capacity Credits.

Consultation Questions:

(17) Do stakeholders agree with the changes to Reserve Capacity Testing for DSPs?

(18) What are stakeholder views on completely aligning the generation and DSP testing regimes?

5.2 Outage Planning

5.2.1 Current Approach

Generation facilities holding Capacity Credits are required to participate in the outage planning process. These facilities must request and receive permission for Planned Outages, and must notify AEMO when a Forced Outage occurs. This ensures that facilities will not be on a Planned Outage during times of likely system stress, and that facilities which are unavailable can be required to pay back some of the money they have been paid to ensure that their capacity will be available.

DSPs do not participate in the outage planning process. Instead DSPs:

- can lodge CDAs to be considered in the CRC process; and
- are judged to be insufficiently available (and pay refunds) when the Relevant Demand (static baseline) of their Associated Loads less the minimum demand of their Associated Loads is less than the quantity of Capacity Credits held.

5.2.2 Required Changes

Outage Planning for Flexible Capacity

When peak capacity is on outage (whether planned or unplanned), it will necessarily be on outage for flexible capacity as well. It is not possible for a facility to provide flexible capacity while its peak capacity capability is on outage.

Given that the RCR for peak and flexible capacity will be different, it is likely that, at times:

- sufficient peak capacity will be available so that some facilities can go on Planned Outage while leaving enough capacity to meet the expected peak demand; while simultaneously
- insufficient flexible capacity will be available to ensure that the expected ramping needs can be met if flexible capacity facilities go on Planned Outage.

As a result, AEMO's outage assessment process (including the opportunistic maintenance process) will need to compare the forecast need for flexible capacity with the remaining quantity of such capacity when deciding which outage requests to approve, which to reschedule, and when to reschedule them to.

> **Proposal M:**
>
> Amend the outage planning process so that AEMO considers availability of both peak and flexible capacity when assessing and approving outages.
>
> **Consultation Questions:**
>
> (19) Do stakeholders agree with the proposed changes to AEMO's outage assessment process?

Outages for Flexible Capacity

The key difference between peak and flexible capacity is the speed with which it can be delivered and the lack of constraints on delivery. With this in mind, the outage regime will need to account for situations where a facility can still provide peak capacity but cannot provide flexible capacity, as follows:

- Participants will need to report technical parameter restrictions affecting facilities holding flexible capacity credits, including ramp rate, minimum stable generation, and minimum start/run/stop times;
- if a facility's parameters become such that it would no longer meet the requirements to be certified as flexible, it would be designated as being on outage for the purposes of flexible capacity. Such an outage could be planned or forced; and
- if AEMO observes a response to dispatch which indicates that a facility's operational parameters do not meet the requirements to be certified as a flexible capacity provider, then the facility would be required to lodge a Forced Outage for the flexible capacity service.

> **Proposal N:**
>
> Require flexible capacity holders to lodge outages relating to capability to provide flexible capacity.
>
> **Consultation Questions:**
>
> (20) Do stakeholders agree with the proposed approach to flexible capacity outages?

DSPs Outage Planning

DSPs do not currently participate in the outage planning process. As noted in section 4.2.4, EPWA is planning to remove the ability of participants to lodge CDAs, with DSP providers managing their own outages without reference to AEMO.

Although DSP providers will no longer have the ability to lodge CDAs, the proposed method for setting DSP CRC (see section 4.2.3) allows for past availability to be considered, meaning DSP owners will still be incentivised to avoid outages at times of likely system stress and can continue to manage their own outages.

The move to a dynamic dispatch baseline means that measuring facility availability against its Relevant Demand will no longer be appropriate. Facility availability for curtailment needs to be measured as the actual demand of Associated Loads less their minimum demand during periods of required availability. This ensures that DSPs are incentivised both to be available for curtailment during system stress periods, and (assuming the DSP availability period remains 8am to 8pm on weekdays) not to contribute to minimum load problems during the middle of the day.

Alternatively, DSPs could be required to lodge Planned Outage requests in the same way as energy producing facilities. Under this approach, DSP outages would be subject to approval by AEMO, and DSPs would not be subject to capacity refunds for being unavailable during these outages.

EPWA considers that the infrequent nature of DSP dispatch and the availability incentives provided by the certification and refund processes mean that allowing participants to schedule their own outages remains appropriate.

If DSP dispatch becomes more frequent, especially if DSPs move away from the top of the merit order, it may become appropriate for them to participate in the outage planning process.

Proposal O:

Allow DSP owners to manage their own outage schedules, without participating in the outage planning regime.

Adjust DSP availability measurement to use actual demand of the Associated Loads rather than the Relevant Demand.

Consultation Questions:

(21) Do stakeholders agree with the proposed approach to DSP outages?

5.3 Refunds

5.3.1 Current Approach

The current peak capacity refund regime assesses capacity payment refunds for a facility on unplanned outage, or with a Planned Outage rate greater than a defined threshold.

Refunds are assessed at a higher rate in periods where most capacity is already generating, and at a lower rate when there is plenty of spare capacity. The rate is capped at 6 when there is less than 750 MW of spare capacity.

A DSP pays capacity refunds if:

- it fails the availability requirement discussed in section 5.2.1; and
- when dispatched, it fails to deliver the requested demand reduction.

If a DSP fails all tests in a Capacity Year and does not demonstrate an ability to curtail by at least 90% of its Capacity Credits, it forfeits its DSM reserve capacity security (25% of expected annual capacity payments).

Collected refunds are distributed to capacity providers who met their availability obligations in the affected intervals.

5.3.2 Required Changes

Flexible Capacity

Capacity refunds are a critical part of the RCM, providing the main incentive for facilities to meet their availability obligations. Capacity refunds therefore need to be in place for flexible capacity to ensure that participants meet their obligations to make capacity available.

Because participants will be paid a single price for their capacity,[22] there is no immediate need to separate capacity payments relating to flexible capacity and those relating to peak capacity. When there is a price premium for flexible capacity, however, it would be possible to calculate two separate payment amounts for each facility:

- one for peak capacity, roughly consisting of the peak capacity price multiplied by the peak capacity credits held; and
- one for flexible capacity, consisting of the difference between the total capacity payments received and the peak capacity amount.

If refunds were drawn from these separate payment amounts, the incentive to meet flexible capacity obligations would be weaker than the incentive to meet peak capacity obligation in all situations where the flexible capacity price premium was less than twice the peak capacity price[23]. In situations where there is no price premium for flexible capacity (likely indicating that peak capacity is in relatively shorter supply than flexible capacity), there would be no price premium, and no separate payment pool.

EPWA considers that this skewed incentive is not appropriate, and that refunds for both products should come from a single payment pool.

RCMRWG members raised concerns about the situation in which there is no price premium for facilities providing flexible capacity. In this situation, facilities would have to pay capacity refunds for both peak and flexible capacity from the same pool of capacity payments. If they are unavailable for the flexible capacity service only but still available for the peak capacity service, they will pay more in refunds than they would have if they had not certified for flexible capacity in the first place. Some participants may choose not to be certified for flexible capacity under such an arrangement.

EPWA considers that this situation is unlikely, as:

- capacity certification occurs in advance of the RCP determination, meaning that participants must decide whether to certify for flexible capacity before knowing whether there will be a price premium;
- there will likely be a price premium in the short to medium term (see Chapter 5.4);
- situations in which facilities are able to meet peak capacity obligations but not flexible capacity obligations are likely to be very rare; and

22 Though facilities providing both peak and flexible capacity can receive a higher price than facilities providing peak capacity only.

23 Consider a 100MW facility providing both peak and flexible capacity. If the peak capacity price is $10 and the flexible capacity price is $15, then total capacity payments would be 100MW * $15 = $1500, of which the peak amount would be 100MW * $10 =$1000, and the flexible amount would be 100MW * $15 - $100 = $500. In this case, a facility falling short of its flexible obligations would face refunds of $5/MW, plus an additional $10/MW if also falling short of peak capacity obligations.

- if a participant considers that it may face a significant risk of lengthy/frequent outages of flexible capacity but not peak capacity, then it is preferable for it to accredit for peak capacity and not flexible capacity.

However, it would be reasonable to cap participant exposure to flexible capacity refunds at some portion of capacity payments to ensure that facilities suffering long term inability to provide flexible capacity still retain some incentive to provide peak capacity.

Proposal P:

Capacity refunds for both peak capacity and flexible capacity will be paid from a single pool of capacity payments.

Capacity refunds for flexible capacity will be capped at a set portion of total capacity revenues.

Consultation Questions:

(22) Do stakeholders agree with the proposed approach to flexible capacity refunds?

(23) If stakeholders consider that the potential refunds for flexible capacity outages should be capped, what proportion of the total payments would they suggest, and why?

The dynamic refund multiplier for peak capacity refunds is an important part of signalling the increased importance of availability at times of system stress. A dynamic refund multiplier can be made specific to the availability of flexible capacity by basing the multiplier on either:

- the remaining available undispatched flexible capacity; or
- the ratio between the actual ramp in the interval and the ramp projected when setting the flexible capacity RCR.

Using the undispatched flexible capacity would mean a low multiplier at the beginning of the ramp, and a higher multiplier at the end of the ramp. This signal does not properly reflect the periods of system stress. It would also mean the multiplier is still based on peak demand, which is not aligned to the incidence of highest ramps, which fall outside the Hot Season.

Using a ramp ratio would mean that the multiplier is consistently highest during periods of highest ramp (with similar profile to that seen in Figure 8), but more volatile. Volatility could be reduced by calculating the actual ramp over multiple prior intervals rather than a single interval.

During an outage that affects both peak and flexible capacity, the appropriate multiplier would be the greater of the two dynamic multipliers.

Predictability could be supported by having AEMO publish ramp rate statistics alongside load forecast.

Proposal Q:

Calculate a dynamic refund multiplier for flexible capacity based on a comparison of the actual ramp requirement in the interval and the ramp rate used to set the flexible capacity RCR.

Apply the greater of the peak and flexible multipliers to refunds for facilities supplying both capacity products.

Require AEMO to publish the projected load ramp rate alongside the load forecast.
Consultation Questions:
(24) Do stakeholders agree with the proposed approach to refund multipliers?

DSPs

A DSP that does not perform currently loses its reserve capacity security only if it never demonstrates that it can reduce demand by 90% of its Capacity Credit allocation in at least two Trading Intervals. As long as it does this at least once, its capacity refunds are capped at its total capacity payments.

Unlike for generation facilities, participants are unlikely to have invested in significant capital expenditure to set up a DSP. This means that the consequences of losing capacity payments are unlikely to be as severe.

To ensure that DSP owners retain an incentive to be available after they have passed their tests, EPWA proposes to:

- include the DSM Reserve Capacity Security in the maximum refund amount for DSPs.
- Require DSPs which voluntarily surrender Capacity Credits during the year to forfeit a pro-rated portion of their DSM Reserve Capacity Security.

Proposal R:
Amend the Maximum Facility Refund for DSPs to include the DSM Reserve Capacity Security.
DSPs which voluntarily surrender Capacity Credits during the Capacity Year will forfeit their DSM Reserve Capacity Security in proportion to the amount of the reduction.
Consultation Questions:
(25) Do stakeholders agree with the proposed approach to DSP refunds?

Capacity Rebates

Currently, collected capacity refunds are distributed to other capacity providers who met their obligations during the relevant periods. The effect of this rule is that consumers still pay for any unavailable capacity, while the refunds are redistributed to increase the capacity payments made to some providers. If AEMO contracts with SRC or NCESS providers to replace the missing capacity, consumers will pay again.

At market start, refunds were distributed to consumers, but this was changed to generators on 1 October 2017 with the commencement of *Wholesale Electricity Market Rules Amending Rules 2016, Schedule B, Part 3*. A paper discussing the allocation of Capacity Rebates[24] noted that:

> *Retailers who benefit from a capacity payment refund will in most cases not experience a power supply disruption – as other capacity providers deliver aggregate capacity to*

[24] https://www.wa.gov.au/system/files/2019-08/Position-Paper-on-Reforms-to-the-Reserve-Capacity-Mechanism.pdf

meet demand. This means that the retailer still receives the service it has paid for in its Capacity Credit obligation, but also receives a refund on that cost for no diminution in that level of service.

While the WEM had an oversupply of capacity in the mid-2010s, it was reasonable to assume that outages resulting in capacity refunds were unlikely to also result in reliability concerns. However, the WEM is now projected to have a shortfall of capacity, resulting in the procurement of both SRC and NCESS to provide additional peak capacity, including to address potential fuel supply issues. If refunds continue to be distributed to generators, consumers (who pay for both SRC and NCESS) will pay more to receive the same level of reliability.

EPWA considers that it is more equitable to distribute collected capacity refunds to participants, responsible for loads that cover the overall cost of the RCM, rather than capacity providers.

Alternatively, collected refunds could be put towards the cost of SRC and/or NCESS, with only the surplus distributed to consumers. This would achieve the same effect as rebating payments to customers but would require more complex intermediate settlement arrangements.

The RCMRWG and the MAC discussed changing the distribution of Capacity Rebates, with consuming participants supporting a change, and most generating participants either neutral or opposing a change.

Proposal S:

Distribute collected capacity refunds to participants, responsible for loads, rather than other capacity providers.

Consultation Questions:

(26) Do stakeholders agree with the proposed distribution of collected capacity refunds?

5.4 The EUE Target in the Planning Criterion

Given the uncertainty about the future reference technology, and therefore the BRCP, the Stage 1 Consultation Paper considered that there was no strong economic justification for changing the EUE target. Based on the analysis presented, submissions supported retaining the target EUE percentage at 0.002%.

At the same time, continuing developments in the WEM and National Energy Market (NEM) reflect Governments' low tolerance for risks to system reliability. The Australian Energy Market Commission recently issued a decision to extend the NEM interim reliability measure[25] of 0.0006% EUE until 2028.

In the WEM, which is a smaller market without interconnections, the recent procurement for 830 MW of NCESS service illustrates this low appetite for risk.

[25] https://www.aemc.gov.au/market-reviews-advice/review-interim-reliability-measure

Further analysis indicates that the peak demand limb of the Planning Criterion will continue to dominate a 0.002% EUE target for some years. The analysis compared the amount of additional capacity required to meet the peak demand limb of the Planning Criterion with the amount of additional capacity required to keep EUE to 0.0015%, 0.001%, 0.0005%, 0.0003% and 0.0002% targets. Preliminary analysis clearly showed that higher EUE targets required much less capacity than the peak demand limb of the Planning Criterion so in depth analysis was performed using 0.0003% and 0.0002% targets only.

Two different mixtures of additional capacity tested in the modelling is summarised in Table 10. New generic capacity was assigned Capacity Credits using a factor of the generator type's nameplate capacity. This was calculated using ESOO 2022 Capacity Credit allocations.

Table 10: Additional Generic Capacity Type, and Capacity Credit Nameplate Multiplier

Additional Capacity Type	Generic Intermittent Capacity-Mix Splits		Capacity Credit Nameplate Multiplier
	Mix 1	Mix 2	
Solar	37.5%	15.0%	0.244
Wind	37.5%	60.0%	0.251
Battery	20.0%	20.0%	1.000
DSP	5.0%	5.0%	1.000

In all scenarios, COLLIE_G1 retires in 2027. Current capacity was sufficient to meet EUE targets in a scenario using the 2022 ESOO's 10% POE peak demand and base annual demand growth. Therefore, a stress test scenario was modelled using 10% POE peak, and high annual demand growth values. The resulting demand is shown in Figure 14.

Figure 14: Peak and Annual Operational Demand

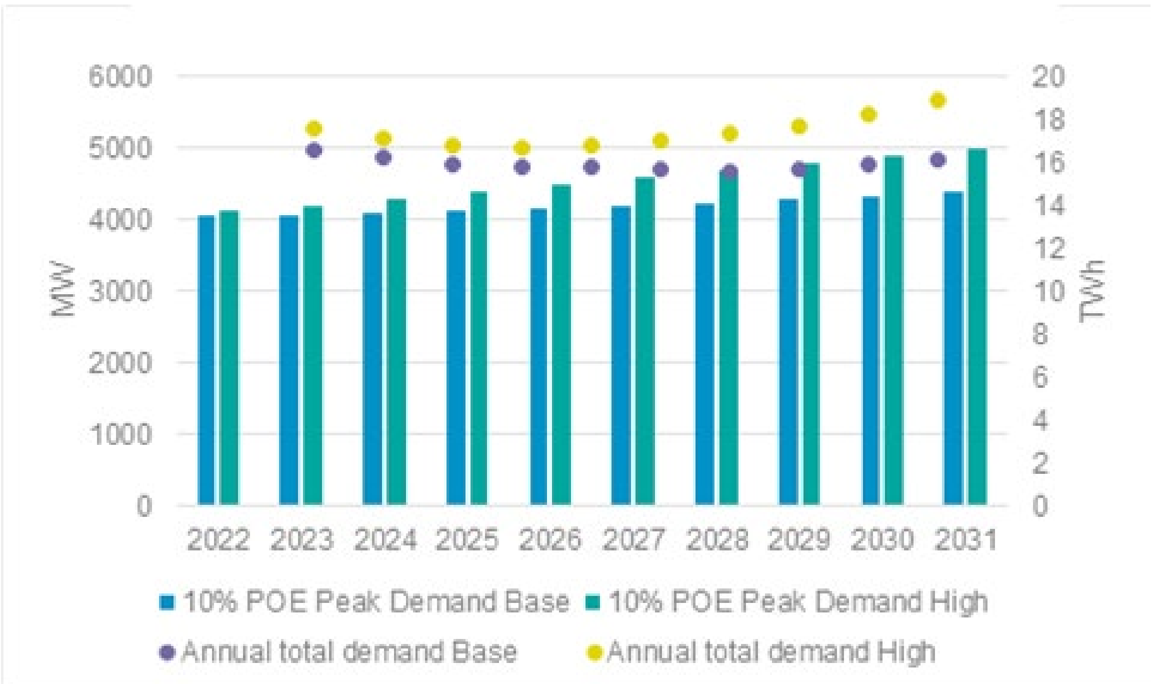
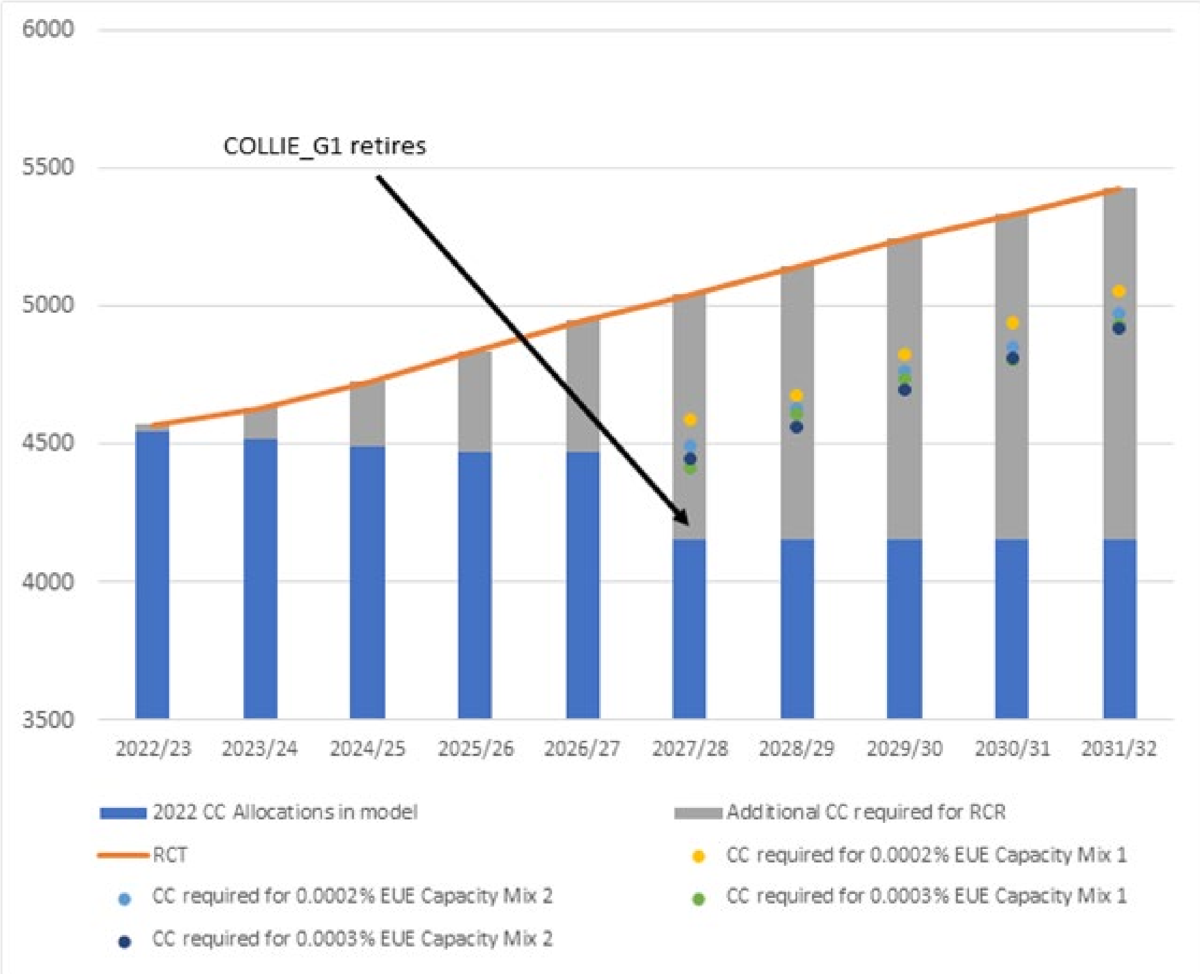


Figure 15 shows that the capacity required to meet the peak demand component of the Planning Criterion exceeds the capacity required to satisfy 0.0002% and 0.0003% EUE targets. This is the case for the high annual demand 10% POE scenario under both scenarios for additional intermittent generation capacity outlined in Table 10. The situation is likely to continue through to the 2040s.

Figure 15: High demand growth 10%POE peak demand EUE and RCT



An EUE target of 0.0002% would bring the EUE limb closer to the peak demand limb, and better reflect the reduced appetite for risk of supply interruptions. This will result in a higher RCR when it binds, at higher cost than the counterfactual. However, analysis shows that the current reliability of electricity supply already exceeds the current EUE target, so leaving the target as-is would leave consumers open to reductions in the level of service provided.

Proposal T:

Amend the target EUE percentage in the second limb of the RCM Planning Criterion to 0.0002% of annual energy consumption.

Consultation Questions:

(27) Do stakeholders agree with the proposed change to a 0.0002% EUE target in the Planning Criterion?

5.5 Determination of the BRCP Technology

Submissions supported having separate capacity prices, with different underlying technologies for each of the peak and flexible capacity products. However, the submissions were concerned that the methodology should consider all elements influencing the price. Of particular concern was:

- the expected commercial life of the asset, which may differ from the theoretical design life; and
- the expected energy storage duration required in the market, which may require more energy than capacity.

Respondents also considered that any significant change to the underlying reference technology should be signalled well in advance.

EPWA agrees that the reference technology for the peak and the flexible capacity products may be quite different, to the point of having a different underlying technology types.

EPWA considers that the underlying technology used in the BRCP methodology would be better reviewed and determined by the Coordinator, with the ERA focusing on the other parameters. The potential move to a net CONE approach is driven by the technology selected, and should also be included in the Coordinator's review.

As with all Coordinator-led reviews, the Coordinator would be required by the WEM Rules to adequately consult with stakeholders on its analysis and proposals.

Such a review must occur before a price can be determined for the flexibility product. To allow flexible capacity to be procured in the 2025 Reserve Capacity Cycle, the review would need to occur in calendar year 2024.

Proposal U:

The WEM Rules will continue to define the BRCP as the per MW capital cost of the new entrant technology with the lowest expected capital cost amortised over the expected life of the facility.

A separate BRCP will be calculated for each of the peak capacity and flexible capacity products. The two capacity products may have a different underlying reference technology, not just different cost components.

The Coordinator will review the appropriate reference technology for each capacity product and, consequently, the use of gross CONE or net CONE to set the BRCP, in 2024.

The Coordinator must review the reference technology and the use of a gross or net CONE approach at least every five years, and may review it more frequently if the Coordinator considers that it has changed considerably.

Consultation Questions:

(28) Do stakeholders agree that the Coordinator should determine the reference technology for each of the capacity products?

(29) Do stakeholders agree that the potential adoption of a net CONE approach should be considered with the reference technology?

6. Financial Analysis

6.1 Introduction

Section 6 details the financial modelling performed to forecast the financial viability of potential new storage and intermittent renewable generation developments, given the design changes proposed under the RCM Review.

There are many permutations of assumptions that could be used for this analysis. The analysis is deliberately conservative on the expected revenue streams for intermittent renewable generation. For example, while it is recognised that Capability Class 3 facilities can provide some ESS (e.g. Contingency Reserve Raise and Lower), the modelling assumes that only Capability Class 1 and 2 facilities provide this.

6.2 Methodology

Robinson Bowmaker Paul's WEMSIM model of the WEM was used to forecast market dispatch and prices from 2024 to 2050 (the modelling horizon). This model forecasts the following market outcomes:

- Facility dispatch for energy and ESS;
- energy and ESS prices;
- cost of generation and cost of energy used by Facilities;
- net energy market revenue including:
  - energy revenue;
  - ESS revenue
    - Regulation Raise revenue;
    - Regulation Lower revenue;
    - Contingency Reserve Raise revenue;
    - Contingency Reserve Lower revenue; and
    - Rate of Change of Frequency (RoCoF) Control Services revenue.

The dispatch model includes:

- daily and seasonal generation profiles for Wind and PV generation;
- optimisation of charge/discharge profiles for ESR facilities;
- start costs and minimum generation levels for key thermal plant;
- a retirement and new build profile based on:
  - retirements of the remaining government-owned coal facilities so that they all are retired by 2030, as announced by Government;
  - retirement of the remaining thermal facilities based on assumed technical lifetimes and an assumption that all carbon-emitting facilities will be retired by 2050; and
  - sufficient new build of wind, PV and ESR to meet the Planning Criterion.

Based on the dispatch model results, a financial model calculates the following on an annual basis:

- the BRCP and the resulting RCP;
- Capacity Credit allocations;
- RCM revenue for peak and flexible capacity products;
- Large-Scale Generation Certificate (LGC) revenue; and
- profitability of existing and new Facilities based on the CONE of candidate new entry technologies.

6.3 Assumptions

6.3.1 Load Profile

The demand profile was generated using values from the 2022 ESOO. Note that the annual demand values are slightly different than the ESOO figures, as the modelling uses the calendar year while the ESOO uses the Capacity Year.

Table 11: Demand Assumptions

Year	50% POE Peak (MW)	Expected Annual Demand (GWh)
2023	3,790	16,443
2024	3,821	16,153
2025	3,855	15,838
2026	3,899	15,738
2027	3,934	15,723
2028	3,967	15,687
2029	4,018	15,610
2030	4,075	15,706
2031	4,141	15,920
2032	4,269	16,180
2033	4,341	16,112
2034	4,419	16,094
2035	4,502	16,076
2036	4,589	16,102
2037	4,680	16,039
2038	4,777	16,020
2039	4,878	15,995
2040	4,985	16,025
2041	5,095	15,960
2042	5,210	15,940
2043	5,331	15,921

Year	50% POE Peak (MW)	Expected Annual Demand (GWh)
2044	5,455	15,943
2045	5,585	15,877
2046	5,719	15,856
2047	5,858	15,835
2048	6,002	15,858
2049	6,150	15,793
2050	6,303	17,198

6.3.2 Fuel Prices

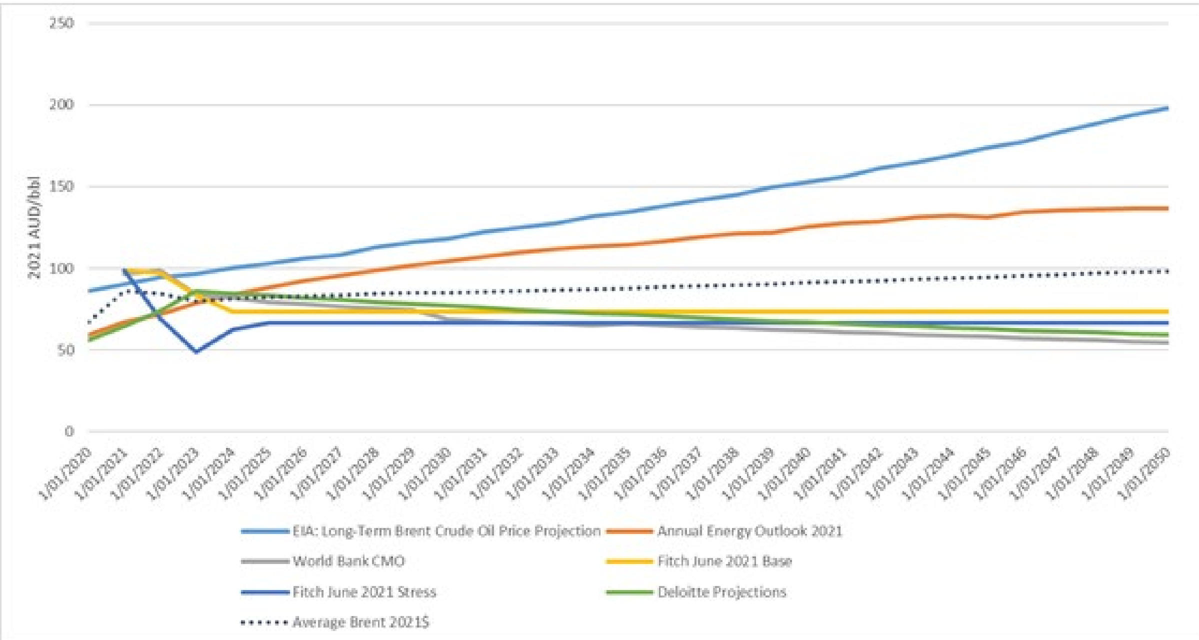
Crude

Crude oil forecasts are used as inputs to the energy price forecasts. The following six published crude outlooks were used as data sources in the model to project the crude oil prices until 2050:

- EIA: Long Term crude oil price projection;
- Annual Energy Outlook 2021;
- World Bank Commodity price forecast;
- Fitch Oil price projections:
  - Base case;
  - Stress case; and
- Deloitte price forecast.

These six crude outlooks are illustrated in Figure 16.

Figure 16: Brent Crude Price Projections



The average of the six crude oil price outlooks were used to generate the assumed Brent Crude Prices that was used in the model.

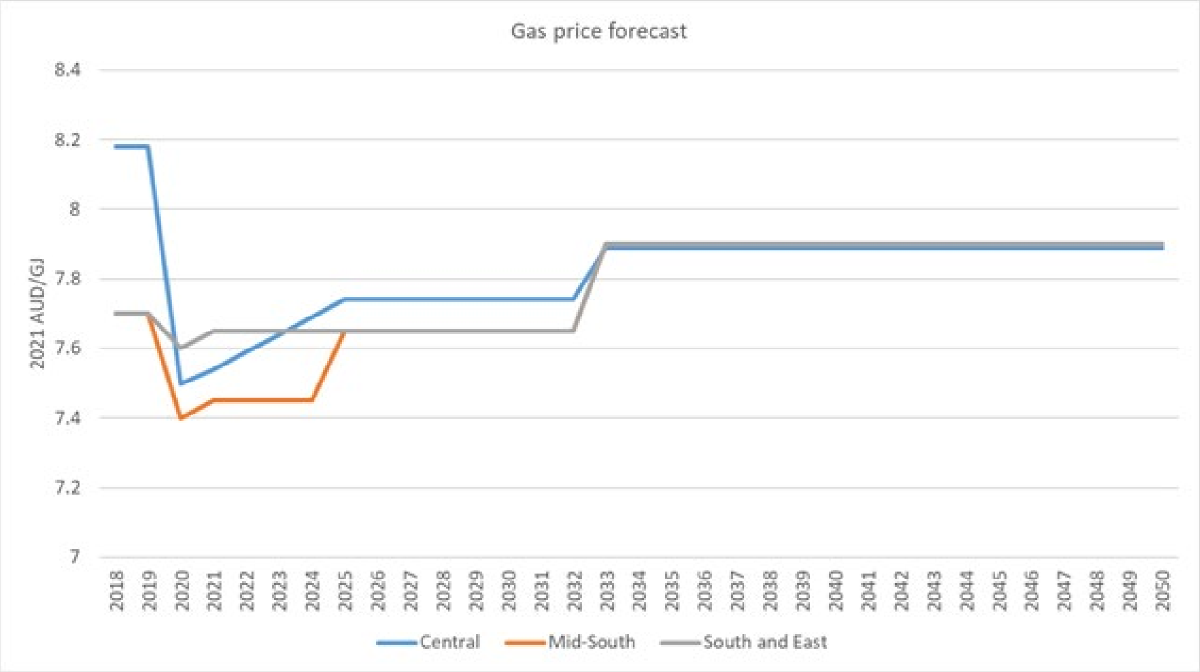
Natural Gas

Gas prices were provided by the base case of AEMO's *Wholesale, Delivered Gas Price Scenarios | 2020 – 2050, Core Energy & Resources, (2021)*. Prices differ regionally as per CORE forecasts and are separated into three groups:

- Central: Kwinana, Pinjar, Neerabup and Cockburn;
- Mid-South: Wagerup and Pinjarra; and
- South and East: Kemerton and Kalgoorlie.

Based on these forecasts, the gas prices used in the model are illustrated in Figure 17.

Figure 17: Gas Price Projection



Coal

Coal-fired generators in WA receive coal directly from WA coal mines under a contract. The terms of these contract are not public, so the cost of this coal must be estimated for modelling purposes.

WA coal is not exported beyond WA, so it does not receive global market prices.

Data on the quantity and value of coal produced in WA is provided in the *2020 Major Commodities Resources Data*, published by the Government of Western Australia Department of Mines, Industry Regulation and Safety.[26] The projected coal prices in Figure

26 https://www.dmp.wa.gov.au/About-Us-Careers/Latest-Statistics-Release-4081.aspx

18 are calculated by taking the average of the last five years' coal prices and assuming a calorific value of 19.7 GJ/t.[27]

Figure 18: Coal Price Projection

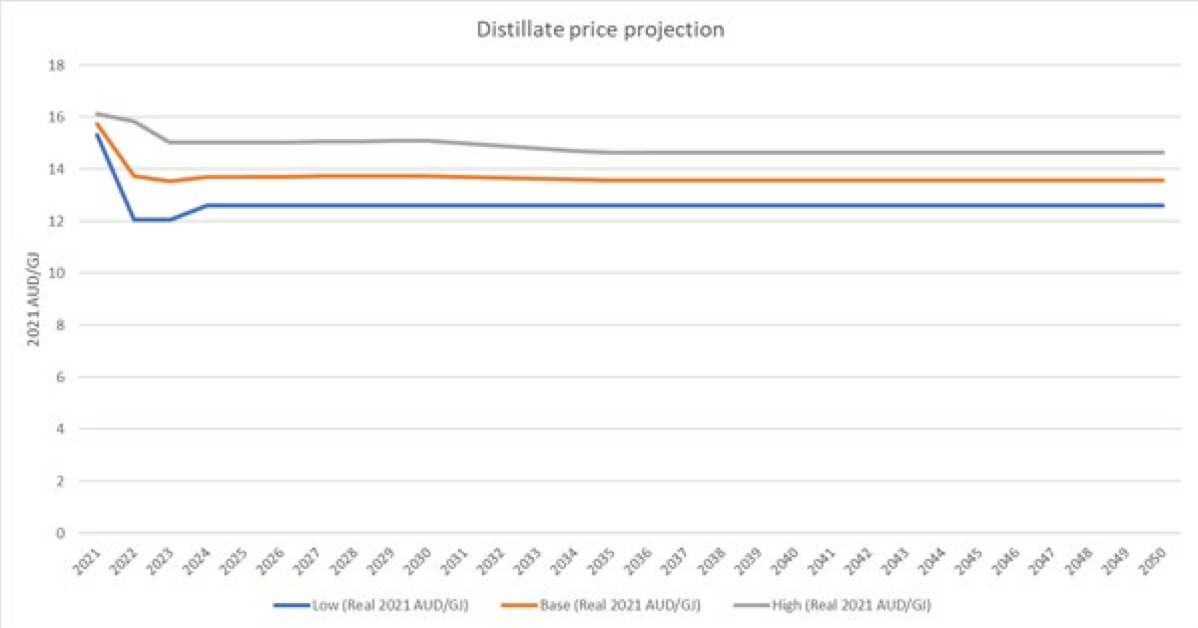
Distillate

Historical "Perth Terminal Gate" prices for distillate (i.e. diesel) are available from the Australian Institute of Petroleum.[28] Diesel prices are strongly correlated with global crude oil prices (e.g. the Brent Crude price), and a linear correlation can be obtained based on historical diesel and crude oil prices. The modelling used the distillate price forecast illustrated in Figure 19, which was obtained by applying this correlation.

27 Guide to the Australian Energy Statistics 2017: https://www.energy.gov.au/sites/default/files/guide-to-australian-energy-statistics-2017_0.docx

28 https://www.aip.com.au/pricing/terminal-gate-prices/perthDiesel

Figure 19: **Distillate Price Projection (2021AUD /GJ)**



6.3.3 Retirements

The retirements used in the modelling are based on either known retirement dates, maximum asset life assumptions or the commitment to zero fossil-fuel generation by 2050. The maximum asset life assumptions are listed in Table 12.

Table 12: Maximum Asset Life

Technology Type	Maximum Asset Life
Black coal	50
OCGT	40
Cogeneration	40
CCGT	40
Diesel engine	35
Wind	40
Solar PV	40
Steam turbine	40

The resulting facility retirement dates are shown in Table 13.

Table 13: Facility Retirement Dates

Facility Name	Retirement Date
ALCOA_WGP	1/11/2048
ALINTA_PNJ_U1	1/07/2046
ALINTA_PNJ_U2	1/07/2046
ALINTA_WGP_GT	2/12/2046
ALINTA_WGP_U2	2/12/2046
BW2_BLUEWATERS_G1	31/12/2049
BW2_BLUEWATERS_G1	31/12/2049
COCKBURN_CCG1	1/07/2043
COLLIE_G1	1/10/2027
KEMERTON_GT11	1/07/2045
KEMERTON_GT12	1/07/2048
KWINANA_GT2	31/12/2049
KWINANA_GT3	31/12/2049
MUJA_G5	1/10/2022
MUJA_G6	1/10/2024
MUJA_G7	1/10/2029
MUJA_G8	1/10/2029
NAMKKN_MERR_SG1	31/07/2047
NEWGEN_KWINANA_CCG1	1/10/2048
NEWGEN_NEERABUP_GT1	19/10/2049
PERTHENERGY_KWINANA_GT1	31/12/2049
PINJAR_GT1	1/07/2029
PINJAR_GT10	1/07/2032
PINJAR_GT11	1/07/2032
PINJAR_GT2	1/07/2029
PINJAR_GT3	1/07/2029
PINJAR_GT4	1/07/2029

Facility Name	Retirement Date
PINJAR_GT5	1/07/2029
PINJAR_GT7	1/07/2029
PINJAR_GT9	1/07/2032
PPP_KCP_EG1	1/12/2036
PRK_AG	1/07/2036
STHRNCRS_EG	1/07/2043
TESLA_GERALDTON_G1	3/08/2047
TESLA_KEMERTON_G1	11/09/2047
TESLA_NORTHAM_G1	11/09/2047
TESLA_PICTON_G1	27/07/2046
TIWEST_COG1	31/12/2049

6.3.4 New Build

The modelling assumed that additional capacity was added to meet the Planning Criterion, using estimates of a capacity type's CRC in the year of build.

Two open cycle gas turbine plants were added in 2025 and 2026 with a total capacity of 350 MW, and were retired in 2040 and 2041 respectively, to reflect a planned 15-year asset life.

If the model identified energy shortfalls, then additional capacity was added to limit unserved energy to acceptable levels. Figure 20 and Table 14 show the new build required to meet these targets.

Figure 20: Assumed New Build

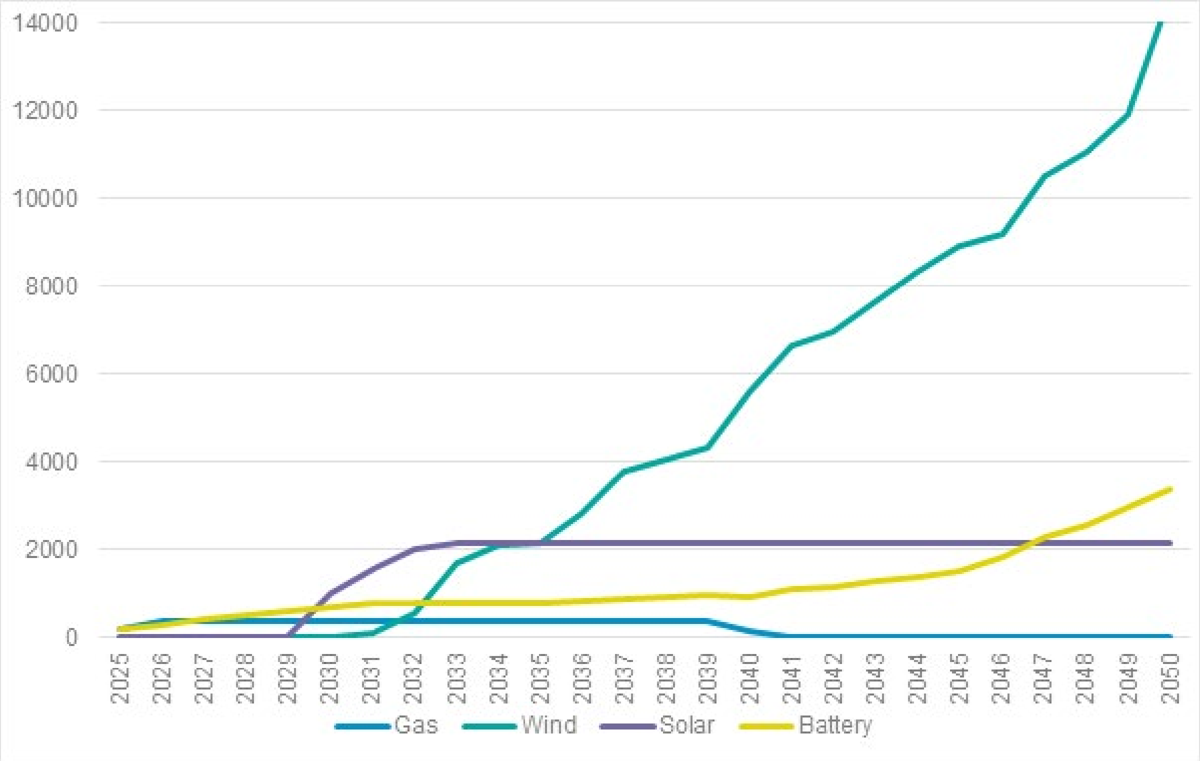


Table 14: Generic New-build Capacity (MW, Cumulative)

Year	Gas	Wind	Solar	Battery[29]
2025	200	0	0	200
2026	350	0	0	300
2027	350	0	0	400
2028	350	0	0	500
2029	350	0	0	600
2030	350	0	1,010	700
2031	350	120	1,570	800
2032	350	557	2,030	800
2033	350	1,685	2,142	800
2034	350	2,119	2,142	800
2035	350	2,127	2,142	859
2036	350	2,844	2,142	848
2037	350	3,786	2,142	869

[29] 2025-2030: 4 hours. 2030-2040: 8 hours, 2040-2050:16 hours.

Year	Gas	Wind	Solar	Battery[29]
2038	350	4,039	2,142	923
2039	350	4,308	2,142	978
2040	150	5,595	2,142	935
2041	0	6,643	2,142	1,092
2042	0	6,955	2,142	1,153
2043	0	7,644	2,142	1,270
2044	0	8,341	2,142	1,388
2045	0	8,913	2,142	1,491
2046	0	9,193	2,142	1,831
2047	0	10,485	2,142	2,282
2048	0	11,057	2,142	2,558
2049	0	11,936	2,142	2,954
2050	0	14,628	2,142	3,391

6.3.5 Service provision

The modelling assumes that:

- FCESS are provided only by gas facilities and storage facilities;
- wind and solar facilities do not provide flexible capacity services; and
- storage facilities can provide synthetic inertia, as otherwise by the end of the modelling horizon there are no facilities left to provide the RoCoF service.

6.3.6 Commercial parameters

WACC

When calculating the CONE for each facility type, a nominal WACC of 5.2% was assumed, to account for financing costs, as specified by the ERA.

LGC Pricing

LGC pricing is based on current, publicly available spot and futures pricing[30] starting at $50/MWh, and reducing linearly to $20/MWh in 2030.

Two LGC scenarios were assessed from 2030:

- scenario 1, in which the Renewable Energy Target ends in 2030, as currently planned; and

30 https://www.mercari.com.au/lgc-closing-rates/

- scenario 2, in which the Renewable Energy Target is continued for the rest of the modelling horizon.

The LGC pricing assumptions are listed in Table 15.

Table 15: LGC Price Assumptions

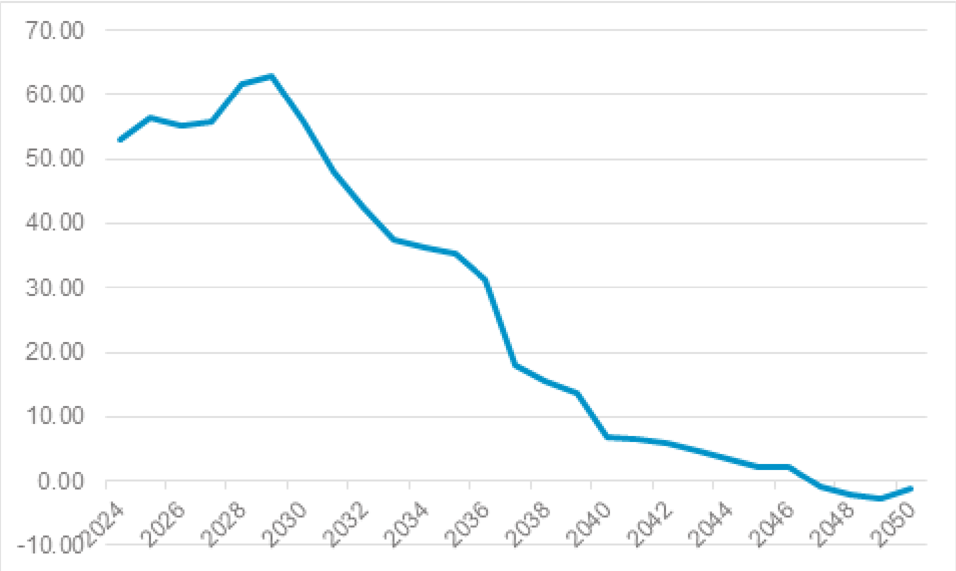
Year	Scenario 1	Scenario 2
2023	$50.00	$50.00
2024	$45.71	$45.71
2025	$41.43	$41.43
2026	$37.14	$37.14
2027	$32.86	$32.86
2028	$28.57	$28.57
2029	$24.29	$24.29
2030	$20.00	$20.00
2031+	$20.00	$0.00

6.4 Results

6.4.1 Real-Time Market Energy Prices

Based on these assumptions, the modelled energy prices rise slightly in the short-run, before gradually collapsing from 2029 onwards. This collapse is due to the overbuild of the low marginal cost intermittent generators required to meet the Planning Criterion. Large amounts of nameplate capacity are required as the CRC of intermittent facilities – particularly solar – reduces as more intermittent generation is built. Figure 21 shows the modelled average real-time energy price in each year.

Figure 21: Average prices ($AUD/MWh)



By the end of the modelling horizon, all thermal plant has retired, and average prices become zero or slightly negative.

6.4.2 Reserve Capacity

Table 16 shows the assumed RCR, the total Capacity Credits of all Facilities in the model, and the resulting RCP for both the peak and flexible capacity products.

The peak capacity price sits at the cap for the whole horizon, driven by assumption of new build quantities to only just meet the RCR. The flexible capacity price starts off at zero, and increases as existing gas facilities retire, reaching the cap in the early 2030s.

The flexible RCR is assumed to flatten from the mid-2030s. This is intended to approximate the implementation of relevant policies, and market behaviour, which reduce the minimum load issue in the middle of the day.

Table 16: Reserve Capacity Summary

Year	Peak Capacity Product		Flexible Capacity Product	
	Reserve Capacity Requirement (MW)	Reserve Capacity Price ($/MW/year)	Reserve Capacity Requirement (MW)	Reserve Capacity Price ($/MW/year)
2024	4,526	170,535	2369	0
2025	4,554	170,535	2497	0
2026	4,605	170,535	2623	0
2027	4,642	170,535	2756	0
2028	4,675	170,535	3253	10,579
2029	4,723	170,535	3407	9,894
2030	4,770	170,535	3556	43,503
2031	4,837	170,535	3680	47,926
2032	4,859	170,535	3810	62,374
2033	4,936	170,535	3934	187,589
2034	5,018	170,535	4000	187,589
2035	5,106	170,535	4000	187,589
2036	5,198	170,535	4000	187,589
2037	5,295	170,535	4000	187,589

Year	Peak Capacity Product		Flexible Capacity Product	
	Reserve Capacity Requirement (MW)	Reserve Capacity Price ($/MW/year)	Reserve Capacity Requirement (MW)	Reserve Capacity Price ($/MW/year)
2038	5,398	170,535	4000	187,589
2039	5,505	170,535	4000	187,589
2040	5,618	170,535	4000	187,589
2041	5,735	170,535	4000	187,589
2042	5,857	170,535	4000	187,589
2043	5,985	170,535	4000	187,589
2044	6,116	170,535	4000	187,589
2045	6,254	170,535	4000	187,589
2046	6,396	170,535	4000	187,589
2047	6,543	170,535	4000	187,589
2048	6,696	170,535	4000	187,589
2049	6,853	170,535	4000	187,589
2050	7,015	170,535	4000	187,589

6.4.3 Reliability of Energy Supply

As generic new build was added to meet the Planning Criterion, there remained sufficient capacity to keep unserved energy to 0 MWh in all years.

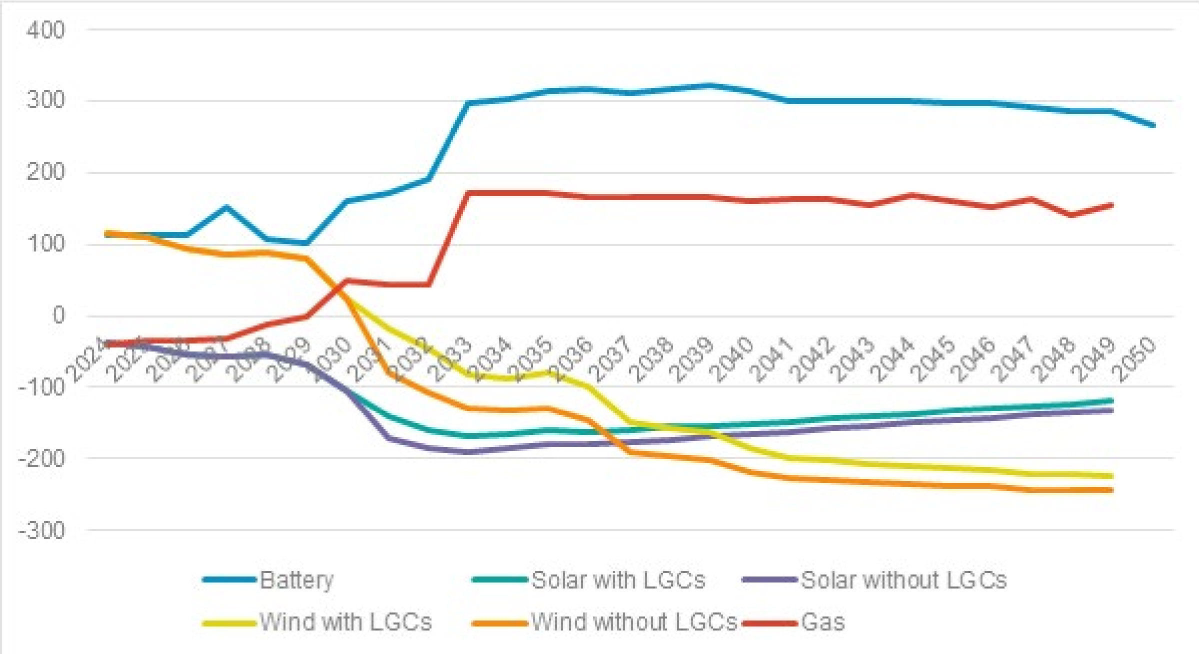
6.4.4 Profitability of New Entry

Figure 22 shows the net profitability of new entry, in terms of $/kW/year. The profitability value is derived by:

(1) calculating the sum of the Facilities' revenue streams from all sources; and

(2) subtracting the capital and fixed costs (including financing costs) for all Facilities, amortised over the Facilities' expected lifespan.

Figure 22: Profitability of New Entrant Capacity ($/kW)



Several features are observed in Figure 22:

(1) The profitability of wind and solar decreases over the first decade of the modelling horizon. This is driven by a decrease in average Real-Time Market (RTM) energy prices and a decrease in Facilities' average capacity factor due to competition with new intermittent generation.

(2) The profitability of batteries and gas increases significantly from 2029 to 2033. This is driven by the retirement of several gas facilities in the period. These retirements push up the RCPs for the flexible capacity product throughout this period until the price reaches the cap in 2033.

(3) The profitability of solar increases from 2033 to 2050. This is driven by forecast decreases in the capital costs of new solar capacity.

6.5 Conclusions

The following conclusions can be drawn from this analysis:

(1) Storage: Revenues from the RTM energy and ESS markets and the RCM (from both the peak and flexible capacity products) are sufficient to support new entry of storage for the whole modelling horizon.

(2) Wind: Revenues from the RTM, the RCM (from the peak capacity product only), and LGCs are sufficient to support new entry of wind until around 2030.

However, building sufficient new entry to meet the Planning Criterion past 2030 will result in decreasing RTM energy prices to the point that total WEM revenues become insufficient for wind generators to cover their fixed and capital costs.

(3) Solar: Revenues from the RTM, RCM (from the peak capacity product only), and LGCs are insufficient to support new entry of solar for the whole modelling horizon.

As noted in section 6.1, this analysis is deliberately conservative on the participation of renewables in non-energy services. Revenue adequacy would likely improve for:

- Capability Class 3 facilities that provide FCESS; and
- intermittent renewable generators with collocated firming which participate in Capability Class 2 and receive more Capacity Credits, including potentially flexible capacity credits.

Without new renewable generation, there will be insufficient energy available to fuel energy storage facilities in later years. EPWA is continuing to consider the above issues outside the RCM Review.

PART THREE – APPENDICES

Appendix A. Responses to the Stage 1 Consultation Paper

Stakeholder	Stakeholder Feedback	EPWA's Response
Conceptual Design Proposal 1 (retain the current approach): Retain the existing 'peak capacity' product to provide an explicit price signal several years ahead of the need for new capacity to meet peak demand and overall energy demand. **Consultation Question (1)**: Do stakeholders support the retention of the existing peak capacity product?		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • Collgar; • Shell Energy;	• Alinta Energy; • Expert Consumer Panel (ECP); • Tesla; and	• Change Energy; • Perth Energy; • Western Power.
EnerCloud	Capacity and flexibility products may not sufficiently cover the full range of potential stress events that are as much about energy availability as they are about capacity.	EPWA acknowledge the existence of potential stress events related to energy availability but considers that these stress events should be addressed outside of the RCM.
Conceptual Design Proposal 2 (retain the current approach): The RCM will not include a specific product to manage minimum demand. The RCM design and the capacity certification process will seek to avoid incentives for new facilities that could make minimum demand more difficult to manage, such as facilities with high minimum stable generation, and/or long start-up, minimum running or minimum restart times. **Consultation Question (2)**: Do stakeholders support the retention of the existing peak capacity product?		
The following stakeholders indicated that they 'support' or generally support the proposal: • Change Energy; • Collgar; • Western Power.	• ECP; • Perth Energy;	• Shell Energy; • Synergy; and
AEMO	AEMO acknowledges that the RCM may not be the right mechanism to manage low load, until the activities under the DER Roadmap and wider low load work program are known.	EPWA will consider the need for a dedicated minimum demand service as part of its Demand Side Response Review.

Stakeholder	Stakeholder Feedback	EPWA's Response
	It may be premature to draw a definitive conclusion in this regard and considers that the modelling undertaken as part of the SWISDA is likely to provide important insights relevant to the impact of low load. Awaiting the outcomes of this work before forming a firm position on the potential for the RCM to contribute in managing low load issues could be beneficial.	
ATCO	The reliance on operational controls, such as ESS markets, to address minimum demand rather than a product in the RCM appears to be a missed opportunity to encourage investment and connection of technologies that can increase demand at these times. ATCO considers there to be value in design proposals for the RCM that: • Encourage connection of flexible loads (such as electrolysers) to build resource adequacy that will support minimum demand rather than a reliance on operational controls.	
Alinta Energy	Alinta Energy agrees that other mechanisms to manage minimum demand will be more effective than designing a bespoke capacity product in the RCM. Alinta Energy supports the intent to avoid inadvertently incentivising new facilities that exacerbate minimum demand issues. However, Alinta Energy suggests these considerations should be balanced with the risk that a given 'inflexible' facility presents to minimum demand, and the benefits the facility can provide in terms of peak capacity, the proposed flexibility product and the broader market.	Review Outcome 13 outlines how flexible CRC will be assigned to facilities. The WEM Rules will require AEMO to consider, as part of the ESOO processes, the capability required of facilities to meet the identified need, ensuring that providers of the flexible capacity can move quickly from no output (or from full consumption) in the midday to rapidly increase output (or decrease consumption) as the high ramp requirements begin. This will allow AEMO to balance the need to mitigate increase in minimum demand with the benefits that a flexible facility can provide.
Synergy	Synergy agrees that a product should not be created within the RCM to address minimum demand, however further consideration is needed on the proposal to "disincentivise" generation that may potentially add to minimum load issues as this will likely add further complexities to the RCM design.	EPWA has worked to ensure that other Review Outcomes and Proposals do not exacerbate minimum demand issues, including in the: • flexible capacity certification requirements (Review Outcome 13); and

Stakeholder	Stakeholder Feedback	EPWA's Response
		• DSP availability requirements (section 4.2.3). EPWA considers that the increased complexity to the RCM design is worthwhile given the benefits from these measures.
Western Power	Western Power supports the recommendation that the RCM not create detriments to managing minimum demand and that the progress on low load actions be monitored throughout the remainder of the RCM review. Western Power expects a generator's minimum stable operating limit and ability to regulate voltage to become increasingly important, particularly during low demand periods. Ensuring sufficient and appropriate generation is available whilst keeping the power system secure is preferable to relying on emergency measures.	See above response.
Conceptual Design Proposal 3: Introduce a new capacity product into the RCM (alongside the existing peak capacity product) to incentivise flexible capacity that can start, ramp up and down, and stop quickly **Consultation Question (3)**: Do stakeholders support inserting a new flexible capacity product in the design of the RCM?		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • ATCO; • ECP; • Synergy; • Alinta Energy; • Change Energy; • Perth Energy; • Tesla; and • AEC; • Collgar; • Shell Energy; • Western Power.		
AEMO	Supports the introduction of a flexible capacity product in the RCM but notes that the Consultation Paper does not consider how the product will be implemented alongside existing transitional pricing arrangements.	Implementation will be subject to the detailed design in stage 3 of the RCM Review.
Australian Energy Council (AEC)	Supports on the basis that it provides an incentive for these products to enter the market and earn sufficient revenue to recover their costs.	A Facility will only be assigned flexible CRC up to a maximum of its peak CRC. In accordance with Review Outcomes 9 and

Stakeholder	Stakeholder Feedback	EPWA's Response
	The obligations on these flexible capacity products should also be aligned to their requirements. In particular, fuel should only need to match the required ramp period.	10, a Facility's fuel availability will affect how much peak CRC a facility is assigned, so the fuel availability requirement will be set by the peak capacity product, and not the flexible capacity product.
Change Energy	Change Energy supports this proposal as it should encourage the introduction of 'firming' generation to support intermittent renewables. However, consideration needs to be given as to how retailers will be able to manage these costs in a way that ensures they will be able to be recovered from customers.	See Proposal E for the proposed method to set the flexible IRCR.
Enercloud	Capacity and flexibility products may not sufficiently cover the full range of potential stress events that are as much about energy availability as they are about capacity.	EPWA acknowledge the existence of potential stress events related to energy availability, but considers that these stress events should be addressed outside of the RCM.
Tesla	We support the creation of a new 'flexible capacity' product, to complement the 'peak capacity' product recognising that both services are tightly coupled yet still interdependent enough to warrant distinct and additive payments. We recommend DER is eligible where it can be registered with AEMO (e.g. under VPP arrangements), as recently announced under Victoria's Storage Target.	EPWA notes that DER can currently participate through DSPs. Any additional DER participation in the WEM will be addressed through EPWA's work in implementing the DER Roadmap.
Western Power	Western Power supports a new capacity product with flexibility to start, ramp-up and down, and stop quickly and supports this new capacity coming from low emission sources and technology.	Preference for low emission technologies may be implemented through the proposed emission thresholds for high emission technologies. EPWA started considering this policy under the RCM Review but will finalise it outside of the RCM Review.

Conceptual Design Proposal 4:

It is not proposed that the Planning Criterion includes reference to volatility in the output of intermittent facilities.

Volatility in operational load and intermittent generation over short timeframes can be managed through ESS and re-dispatch. The addition of the flexible capacity product, proposed under the Conceptual Design Proposal 3, is expected to provide adequate capacity that is capable of providing these services.

Consultation Question (4): Do stakeholders support not amending the Planning Criterion to include consideration of the volatility of intermittent generators?

Stakeholder	Stakeholder Feedback	EPWA's Response
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • Collgar; • Shell Energy; • Alinta Energy; • ECP; • Synergy; and • Change Energy; • Perth Energy; • Western Power.		
AEMO	AEMO supports the design proposal, but notes that there may be other system stress events which drive the quantity (MW) and capability (MW/min) of flexible capacity in the WEM. Specifically, the analysis currently considers only the evening ramp event which may determine lower ramping capability (MW/min) than required by AEMO to manage ramping events associated with volatility. AEMO can provide data to support the current volatility challenges, which emerge in shorter timeframes than undertaken in the presented modelling, i.e., over 15-30 minutes, which may not have been captured in the hourly assessments undertaken in this work.	The system stress analysis undertaken in Stage 1 of the RCM Review indicate that the ramping requirement caused by volatility should be manageable if sufficient capacity is available to address the flexible capacity requirement. The analysis compared the MW/min ramping requirement caused by volatility with the expected ramp requirement for the flexible capacity product. The analysis also showed that the evening ramp requirement is higher than the morning ramp. Frequency regulation cost allocation is considered as part of EPWA's review of cost allocation methodologies. Facilities holding flexible capacity credits are likely to be able to, and to want to, provide some or all of the FCESS. Under Review Outcome 4, facilities holding flexible capacity credits will be required to accredit for all types of FCESS that they are capable of providing.
Change Energy	In general, Change Energy supports this proposal. However, we consider there should be mechanisms to attribute the costs associated with intermittent generation volatility back to those generators. This is consistent with the causer-pays basis that many other costs in the WEM now use to allocate costs. We consider this will serve as an incentive to improve the accuracy of intermittent forecasts and/or reduce generation volatility directly.	Allocation of ESS costs to address volatility in generation is being assessed under the Cost Allocation Review. The objective of the Cost Allocation Review is to allocate the costs based on the causer-pays principle.

<table>
<tr><th>Stakeholder</th><th>Stakeholder Feedback</th><th>EPWA’s Response</th></tr>
<tr><td colspan="3">Conceptual Design Proposal 5:
The two current limbs of Planning Criterion will be retained, requiring sufficient capacity to:
• meet the 10% POE demand, and
• achieve EUE no greater than a specified percentage of expected demand.
Consultation Question (5): Do stakeholders support retention of the current two limbs of the Planning Criterion?</td></tr>
<tr><td colspan="3">The following stakeholders indicated that they ‘support’ or generally support the proposal:
• AEMO;
• Collgar;
• Shell Energy;
• Alinta Energy;
• ECP;
• Synergy; and
• Change Energy;
• Perth Energy;
• Western Power.</td></tr>
<tr><td>Change Energy</td><td>Change Energy generally supports this approach. This was reviewed a number of years ago the results seemed reasonable. However, the actual outcome has resulted in the level of excess capacity (effective reserve margin) being greater than 40% and in some years 60%. This is not necessarily in the best interests of customers who bear these costs. Change Energy would like to see a review of previous years forecasts compared to actuals to see if there are any areas of improvement.</td><td>EPWA notes the request to review the forecast accuracy. However, this is out of scope of the RCM Review.</td></tr>
<tr><td colspan="3">Conceptual Design Proposal 6:
Amend the reserve margin so that:
• sub-clause 4.5.9(a)(i) uses the (AEMO determined) proportion of the generation fleet expected to be unavailable at system peak due to forced outage, rather than a hardcoded percentage; and
• sub-clause 4.5.9(a)(ii) refers to the largest contingency on the power system, rather than the largest generating unit.
Introduce the proposed amendment to clause 4.5.9(a)(ii) to change the determination of the largest contingency for the calculation of the reserve margin, in time for the 2023 Reserve Capacity Cycle (for the Capacity Year starting on 1 October 2025).
Consultation Questions
(6)(a): Do stakeholders support amending the reserve margin as indicated in Conceptual Design Proposal 6?</td></tr>
</table>

Stakeholder	Stakeholder Feedback	EPWA's Response
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • Alinta Energy; • Collgar; • ECP; • Perth Energy; • Shell Energy; • Synergy; and • Western Power.		
AEMO	Provided general support. AEMO also notes that the changes to 4.5.9(a)(i) will require we undertake an assessment of historical outages, for which there should be sufficient guidance. This could be achieved through the provision of high-level principles under the WEM Rules, with a requirement on AEMO to develop a WEM Procedure that accords with the principles.	This will be considered in stage 3 of the RCM Review.
Alinta Energy	Indicated support with some considerations for detailed design: The drafting should define what is meant by "historical" facility forced outage rates. Consideration will need to be given to the fact that forced outage quantities currently overstate outages. Under the current rules, forced outage quantities are calculated as the difference between a participant's maximum capacity and what it was able to provide. Consequently, where a participant has a partial deviation from a dispatch instruction that is much lower than its total capacity, the resulting forced outage is significantly overstated. AEMO should be required to draft a methodology procedure to allow for both a consistent approach year on year and for participants to be able to replicate the expected outcome in their own modelling, which is vital as a normal part of business.	How forced outages are calculated, if a Facility fails to comply with a dispatch instruction, was subject to stakeholder consultation during the development of the relevant WEM Amending Rules to implement the new WEM.
Synergy	Synergy agrees that amendments to the Planning Criterion to address these concerns is appropriate but cautions that care is needed to ensure the reserve margin does not overstate the issues. Synergy notes that the historic performance of facilities may not always be the best assumption for future performance and that a level	EPWA notes the suggested drafting. This will be considered during stage 3 of the RCM Review.

Stakeholder	Stakeholder Feedback	EPWA's Response
	of flexibility may be required in determining the capacity "expected" to be unavailable. To address this concern, Synergy suggests the drafting of clause 4.5.9(a)i is amended to: 4.5.9(a)i. the forecast peak demand (including transmission losses and allowing for Intermittent Loads) multiplied by the reasonable expectation of the proportion of unavailable capacity ~~expected to be unavailable~~ at the time of peak demand based on historical facility forced outage rates; and…	
Consultation Questions **(6)(b):** Do stakeholders have any concerns about the proposed amendments to clause 4.5.9(a)(ii)?		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • Alinta Energy; • Collgar; • ECP; • Perth Energy; • Shell Energy; • Synergy; and • Western Power.		
AEMO	Supports the design proposals to remove the hardcoded percentage under clause 4.5.9(i) and allow for the potential that the largest system contingency is not a generator under clause 4.5.9(a)(ii). However, does not support the drafting proposed. Specifically, we have concerns regarding the proposed removal of the following text from clause 4.5.9(a) "while maintaining the SWIS frequency in accordance with the Normal Operating Frequency Band and the Normal Operating Frequency Excursion Band." The practical effect of this change is that the RCT calculation will no longer include an additional amount of capacity required to provide Minimum Frequency Keeping Capacity and ensure that LFAS is maintained. As a result, it will likely reduce the RCT determined (for example, this would reduce the RCT by 110MW in the 2024-25 Capacity Year). The Consultation Paper does not provide the rationale for this change and AEMO believes this is not aligned with the RCM Review's condition (page 2) that any changes to the RCM should not erode the level of system	EPWA further amended the proposed drafting in consultation with AEMO. The change commenced on 1 January 2023 as part of the *Wholesale Electricity Market Amendment (Tranche 6 Amendments) Rules 2022*, following its approval by the Minister.

Stakeholder	Stakeholder Feedback	EPWA's Response
	reliability currently provided for by the WEM Rules. AEMO recommends maintaining these words in the final drafting to implement the intention of design proposal 6. AEMO also notes that the changes to 4.5.9(a)(i) will require we undertake an assessment of historical outages, for which there should be sufficient guidance. This could be achieved through the provision of high-level principles under the WEM Rules, with a requirement on AEMO to develop a WEM Procedure that accords with the principles.	
Change Energy	Change Energy has concerns with the changes to clause 4.5.9(a)(ii) of the WEM Rules. The purpose of the RCM is to ensure sufficient generation capacity is available, not that network contingencies are accounted for.	As a result of the amendments made in late 2022 (see above), the reserve margin set out in the Planning Criterion is to cover the largest contingency in the SWIS. Historically, under unconstrained network access, this was the largest generating unit. However, with the move to constrained network access, the largest contingency can now differ from the largest generating unit. EPWA considers that this change was required to ensure adequate system reliability, noting that the AEMO analysis has indicated that the largest contingency is unlikely to be caused by a network contingency in the foreseeable future.
Perth Energy	Perth Energy agrees in principle with using the largest contingency on the power system as part of the planning criteria. Our concern is that with the implementation of constrained network access this could be a very large MW figure if substantial quantities of new generation capacity are connected through a single potential failure point. We recall that this matter arose when the Interim Access Arrangement was implemented by Western Power. Some arrangement would be required to ensure that any increased cost of reserve capacity (and spinning reserve) is optimised with the cost of mitigating potential weak points on the network.	EPWA notes that, under the recently implemented WEM Rules, Western Power is required to consider market impacts in its transmission network planning.

Stakeholder	Stakeholder Feedback	EPWA's Response
Synergy	With a constrained network in the new market, network contingencies will be an important consideration for reliability and need to be considered within the Reserve Margin. However, a balance is needed to ensure that alternative reliability solutions (such as network upgrades) continue to be reviewed and considered. Where alternative solutions are available, a cost benefit analysis should be undertaken to ensure that the approach (either increasing the Planning Criterion or a network solution) provides the best outcome for consumers. Synergy notes that the methodology used in the assessment for the contingency requirements should be aligned with the expectation of market dispatch outcomes that may potentially curtail to limit network contingencies where this would result in the lowest cost dispatch outcome.	EPWA notes that, under the WEM Rules, Western Power is required to consider market impacts in its transmission network planning. EPWA notes that the contingency considered for the Planning Criterion must be based on expected dispatch during a 1-in-10 year peak demand, which is likely to be different to market dispatch at other times.
Consultation Questions **(6)(c):** Do stakeholders support commencing the proposed amendments to clause 4.5.9(a)(ii) for the 2023 Reserve Capacity Cycle?		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • Perth Energy; • Collgar; • Shell Energy; and • ECP; • Western Power.		
Change Energy	Change Energy believes that clause 4.5.9(a)(ii) needs further analysis to determine the additional cost burden that places on customers prior to any decision, and therefore should not be introduced for the 2023 Reserve Capacity Cycle.	Based on consultation with AEMO, EPWA considered that the change was urgently needed to protect system reliability. Therefore, the change, including drafting changes to address AEMO's concerns raised under Consultation question 6(b), was approved by the Minister and commenced on 1 January 2023 as part of the *Wholesale Electricity Market Amendment (Tranche 6 Amendments) Rules 2022*.
Conceptual Design Proposal 7: The target EUE percentage in the second limb of the Planning Criterion will remain at 0.002% of annual energy consumption. **Consultation Question (7)**: Do stakeholders support retaining the target EUE percentage at 0.002?		

Stakeholder	Stakeholder Feedback	EPWA's Response
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • Collgar; • Shell Energy; and • Alinta Energy • ECP; • Western Power. • Change Energy • Perth Energy;		
Collgar	Provided support. However Collgar notes that the VCR used was from the National Electricity Market. Ideally, a local VCR would be used if it could be cost-effectively obtained.	EPWA notes that the cost of unserved energy ($48.10/kWh) used in the analysis is adopted from Western Power's work on the VCR for the SWIS.[31]
Conceptual Design Proposal 8: The Planning Criterion will include a third limb requiring AEMO to procure flexible capacity to meet the size of the steepest operational ramp expected on any day in the capacity year from either the 10% or 50% POE load forecasts. **Consultation Question (8)**: Do stakeholders support the proposed third limb of the Planning Criterion to require AEMO to procure flexible capacity? If so, is the proposed criterion appropriate?		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • Change Energy; • Perth Energy; • Western Power. • Alinta Energy • Collgar; • Shell Energy; • ATCO; • ECP; • Synergy; and		
Conceptual Design Proposal 9: The ERA will remain responsible for setting the detail of the method used to calculate the BRCP. The WEM Rules will provide guidance for the ERA on the factors to be considered in setting the BRCP methodology.		

31 Western Power's estimation of VCR can be found on the ERA's website in the document AAI – Attachment 6.3: Access Arrangement 2022-2027 - Economic Regulation Authority Western Australia (erawa.com.au).

Stakeholder	Stakeholder Feedback	EPWA's Response
Consultation Questions **(9)(a):** Do stakeholders support retaining the ERA as the agency that is to set the BRCP?		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • Collgar; • Shell Energy; and • Alinta Energy • ECP; • Western Power. • Change Energy; • Perth Energy;		
Consultation Questions **(9)(b):** Do stakeholders support providing guidance to the ERA in the WEM Rules on the factors to consider in setting the BRCP?		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • Collgar; • Shell Energy; and • Alinta Energy • ECP; • Western Power. • Change Energy; • Perth Energy;		
Alinta Energy	Indicated support with some considerations for detailed design: The BRCP methodology will need to balance investment certainty with the need for flexibility to respond to emerging inflation pressures, commodity issues and tightening markets. For example, the previous BRCP had hard-coded in some WACC parameters which led to anomalous outcomes.	The detailed design will be further considered in stage 3 of the RCM Review. Note that Proposal U is for the Coordinator to consult on and decide on the reference technology and the use of gross vs net CONE.

Stakeholder	Stakeholder Feedback	EPWA's Response
Conceptual Design Proposal 10: The WEM Rules will define the BRCP as the per MW capital cost of the new entrant technology with the lowest expected capital cost amortised over the expected life of the facility. A BRCP is to be calculated for each of the peak capacity product and the flexible capacity product, and the BRCP methodology must differentiate between the two, taking into account any differences between the reference technologies used for each product, where appropriate. The ERA review of the BRCP methodology (under clause 4.16.9 of the WEM Rules) must consider the appropriate reference technology, the design life of the relevant facility, and identify any cost components that differ between the technology providing the peak capacity product only and that providing the peak capacity plus the flexible capacity product. The ERA can review the BRCP methodology more frequently than every five years, if it considers that the reference technology has changed significantly, and must consult with stakeholders each time it does. **Consultation Questions** **(10)(a):** Do stakeholders support the proposed approach to the BRCP? **(10)(b):** Do stakeholders support the calculation of separate BRCPs for the peak and flexible capacity products? **(10)(c):** Do stakeholders support the proposed factors for the ERA to consider in reviewing the BRCPs?		
The following stakeholders indicated that they 'support' or generally support the proposals: • AEMO; • Change Energy; • Perth Energy; • Alinta Energy • Collgar; • Shell Energy; and • Synergy; • ECP; • Western Power.		
Alinta Energy	Tentatively supported with qualifications. Alinta Energy has some concerns with aspects of the BRCP definition: • Whether it should consider the cost of installed MWhs of capacity as well rather than MWs only, noting that this would be required to recover the cost of retaining the fuel requirement in a tightening gas market, and the cost of storage where MWhs not MWs tend to drive fixed costs and would be required to meet the proposed duration requirement.	As noted under Review Outcome 7, further consideration on the approach to setting the reference technology for the BRCP methodology was required. EPWA has included a new proposal in the Stage 2 Consultation Paper. The BRCP will be set based on a facility located in an uncongested part of the network. If there is no uncongested part of the network, the BRCP will be set based on a facility located where there is limited congestion. The guidance in the WEM Rules will include a principle to set out process steps to determine parameter values in preference to recording only a fixed parameter value, especially where

Stakeholder	Stakeholder Feedback	EPWA's Response
	• Careful consideration is required on how the 'expected life' is determined, noting the material implications for price and therefore investment signals. While Alinta Energy supports the ERA reviewing the BRCP methodology as frequently as it needs to, for investment certainty, we consider that there needs to be sufficient notice of a change in reference technology.	those parameters are likely to change markedly from year to year. EPWA also notes that, as an outcome of the market power mitigation strategy review, the Wholesale *Electricity Market Amendment (Tranche 6A Amendments) Rules 2023* introduced clause 2.16D.1. Upon commencement, this clause will require the ERA to develop an offer construction guideline that permits recovery of costs incurred under long-term take-or-pay fuel contracts.
Change Energy	Change Energy generally supports these approaches but does not support the current State Government proposal to penalise carbon emitting capacity. If a penalty regime of this nature is introduced the BRCP will need to be thoroughly reviewed to ensure it is fit-for purpose. We expect it will need to be completely revised. Change Energy has concerns that the benchmark technology will be changed to battery energy storage systems. This, together with the proposed carbon emitting penalty will significantly disadvantage existing peaking generation which are critical to transition to a renewable future.	The proposed emission thresholds for high emission technologies will be further assessed outside of the RCM Review. The issue raised by Change Energy will be considered.
Perth Energy	In principle, yes. While difficult, it may be more appropriate for the ERA to consider the commercial or effective life of the facility rather than its design life.	EPWA acknowledges the concern over a mismatch between the time/technical parameters that affect revenue and the expected life of an investment, particularly in relation to longer duration storage facilities. EPWA is examining this issue separately.
Synergy	Synergy generally supports the proposed design changes for the BRCP but further consideration is needed for some of the elements. Synergy notes that the BRCP in general is much higher than the resulting RCP that facilities receive, and although the BRCP methodology is out of scope of this review, changes may be required to ensure that revenue adequacy for efficient investment can be achieved in the WEM.	See above response to Alinta Energy's feedback.

Stakeholder	Stakeholder Feedback	EPWA's Response
	The BRCP (and resulting RCP) need to be considered alongside the likely revenues from the energy and ESS markets to ensure that all efficient costs can be recovered. Further, the "duration obligations" and associated costs are not currently considered within the BRCP and is likely to need to be further explored to ensure that these costs are recoverable from the WEM. Synergy is cognisant that the final design of the Market Power Mitigation framework is crucial to understanding the revenue adequacy outcomes of the WEM. Synergy considers that the following factors should be considered in the determination of the BRCP: 1. Ensuring efficient costs that are associated with the RCM that are not recoverable within the other revenue streams are accounted for within the BRCP (such as market fees and costs associated with meeting certification obligations); 2. Facilities that are providing the flexible capacity product may have a different life expectancy due to the different dispatch expectations...Synergy notes that even when the reference technology is the same for both BRCPs, the facility life is likely to differ. The potential for network constraints and lower NAQs for the reference technology needs to be considered and modelled;	

Conceptual Design Proposal 11:

Where the RCM reference technology has the highest short-run costs in the fleet, the BRCP methodology can use the simpler gross CONE approach, as this will be the same as the net CONE.

Where the RCM reference technology does not have the highest short-run costs in the fleet, the use of net CONE approach would need to be considered together with all other factors that may influence investment decisions.

The BRCP will be set based on a facility located in the least congested part of the network. If there is no uncongested network location to accommodate the size of the lowest fixed cost technology, the NAQ regime may affect the choice of reference technology. This location will be considered as part of the ERA's regular review of the BRCP methodology.

Consultation Question (11): Do stakeholders support the proposed consideration of gross CONE and net CONE for determining the BRCP, as indicated in Conceptual Design Proposal 11?

Stakeholder	Stakeholder Feedback	EPWA's Response
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • Change Energy; • ECP; • Perth Energy; and • Shell Energy.		
Alinta Energy	Support retaining gross CONE, noting that under a gross CONE approach, congestion does not need to factor in the BRCP calculations. Do not support moving to net CONE at any stage. We understand that the key risk that this approach aims to resolve is storage capacity receiving excessive returns due to it not having the highest short-run costs and being overcompensated where more expensive facilities set the price. Noting MJA's and ERA's findings about revenue adequacy for storage and flexible capacity, we suggest that a greater risk is inadequate incentives for investment and therefore that a net CONE approach may: - introduce significant complexity for negligible benefit, and - undermine investment certainty, noting the difficulty of forecasting the energy and ESS revenues a storage facility may derive from the WEM to adjust the BRCP (especially as intermittent generation and storage capacity continue to increase).	Review Outcome 7 specifies that any change to net CONE will require accompanying analysis and consultation.
Collgar	Collgar does not support the use of the net CONE to calculate the BRCP as there is a risk a Market Participant will not be made 'whole'. Market Participants may bid below their short-run marginal cost (SRMC) in real-time markets to meet their commercial obligations, meaning that clearing prices may not be reflective of the SRMC of the facility. If the net CONE approach is adopted, it is likely that a 'top up' payment through the RCM would be required to make Market Participants whole in the case of zero or negative energy prices. This adds complexity (and cost) to an already complex mechanism and for this reason Collgar prefers the gross CONE approach.	

Stakeholder	Stakeholder Feedback	EPWA's Response
Synergy	Synergy suggests that significant consultation and modelling should be undertaken if there was a proposal to switch to net CONE. • The Paper suggests that ESS revenues should be considered in a net Cone approach, however Synergy cautions that the full impacts of ESS dispatch, such as facility degradation also need to be included; • The assumptions used to determine net CONE need to be very conservative to ensure that facilities are still able to recover their efficient costs, noting the need for revenue adequacy in the WEM; Synergy suggests that the gross Cone continues to be applied until there is actual WEM based data on the new reference technology that can better inform assumptions in the modelling.	
Western Power	Western Power seeks clarity as to whether the reference facility location needs to be the 'least congested part of the network' or any suitable 'uncongested part of the network'. The former could result in unnecessary analysis to determine which part of the network is 'least congested'.	Review Outcome 7 specifies that the BRCP will be set based on a facility located in an uncongested part of the network. If there is no uncongested part of the network, the BRCP will be set based on a facility located where there is limited congestion.
Conceptual Design Proposal 12: The administered RCM price curve for the flexible capacity product will be the same as the one used for the peak capacity product, as defined in WEM Rule 4.29.1(b)(iv). The capacity price paid to a facility providing flexible capacity will never be lower than the peak capacity price. Proposed facilities will have the option to seek a five-year fixed price for flexible capacity, on the same basis as is currently available for peak capacity. A facility must opt for a fixed price for both products, it cannot select fixed price for one product and floating price for the other. **Consultation Questions** **(12)(a):** Do stakeholders support using the same price curve for the peak and flexible capacity products? **(12)(b):** Do stakeholders support the proposed pricing arrangements for the flexible capacity product?		

Stakeholder	Stakeholder Feedback	EPWA's Response
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • ECP; • Change Energy; • Perth Energy; and • Collgar; • Shell Energy.		
Alinta Energy	Provided tentative support with qualifications. We suggest further consideration of whether amendments to the current price cap and floor regime are required to ensure existing capacity has appropriate signals to participate. In the absence of a separate investment initiative, a broader review of peak capacity product price curve (existing RCP curve) may be required to resolve the issues about revenue adequacy and uncertainty raised by MJA and the ERA's effectiveness review.	The Reserve Capacity Price is out of scope for the RCM Review but EPWA notes the concern and will consider it separately.
Consultation Questions **(12)(c):** Do stakeholders support a 5-year fixed price option for proposed flexible capacity facilities?		
The following submissions indicated that they 'support' or generally support the proposal: • AEMO; • ECP. • Change Energy; • Collgar; and		
Alinta Energy	Provided tentative support with qualifications. We have some concern that the current conditions for fixing a capacity price are only available where the excess level is within a very narrow band and suggest consideration of whether these conditions should be broadened both for flexible and peak capacity products. Given the revenue adequacy and uncertainty concerns for flexible capacity highlighted by MJA and ERA's effectiveness review, we suggest further consideration of whether the proposed price curve, BRCP method and 5-year contracting scheme are sufficient to bank a project before the expected shortfall in capacity is expected in 2027, or whether further practical considerations are required.	EPWA considers that fixed price arrangements should only be available to new facilities that are needed to meet the RCR. The primary purpose of the RCM is to ensure adequate system reliability for the benefit of consumers. Allowing facilities that are not needed to meet the RCR to enter a fixed price agreement would come at a cost for consumers without providing commensurate benefit. The Reserve Capacity Price is out of scope for the RCM Review but EPWA notes the concerns and will consider this separately.

Stakeholder	Stakeholder Feedback	EPWA's Response
ATCO	The relative infancy of markets for flexible capacity products means that additional certainty on price is needed for investments in flexible capacity technologies. ATCO considers there to be value in design proposals for the RCM that encourage price certainty on products beyond five years to provide investors with confidence to invest in flexible capacity technologies.	EPWA notes the concerns about the length of the fixed price period for new technologies and is examining these issues separately.
Perth Energy	Perth Energy supports a fixed price option but considers five years to be too short given the market risks. This is addressed further in Perth Energy's submission.	
Shell Energy	Supportive of a fixed price option for proposed flexible capacity, however, with regard to the duration of the fixed price, we consider 5 years to be insufficient and a longer duration fixed price would be more appropriate. There is a considerable reliance on investment in the WEM and a 5-year fixed price may not encourage investor confidence, given that between now and 2030, new capacity is required over a 7-year period to replace retiring assets, yet the fixed price option is only 5 years.	
Synergy	Synergy supports the proposal that the capacity price applied to facilities that meet the requirements of both the peak and flexible capacity products is set at the higher of the RCPs and that the facility can "lock-in" the price. However, Synergy suggests that a five-year lock-in period may not provide sufficient revenue certainty (for both the peak and flexible capacity products) and should be reviewed	
Tesla	To support new build, RCM payments should include an option of fixed price contracts with sufficient tenure (e.g. 10 – 15 years) with appropriate discount relative to highly sensitive RCM pricing.	
AEC	While the AEC supports a fixed price option, it is timely for EPWA to review the RCP methodology and consider the merits of longer, 15-year fixed contracts, as proposed by FTI Consulting and MJA, to	See responses above.

Stakeholder	Stakeholder Feedback	EPWA's Response
	ensure investors have sufficient certainty to enter the market. Most generation types do not and will not earn sufficient revenue, and investors are not incentivised to enter under the current market settings in the WEM. The volatility in the current RCP does not support long term investment in flexible generation and storage facilities, and it is unlikely that a 5-year fixed capacity price will be enough to underwrite investment in new flexible generation and storage in the WEM. AEC recommends: 1. That EPWA review the RCP methodology and consider what changes are required to ensure the RCP is sufficient to support efficient investment in new capacity when it is required; and 2. Investors who are willing to invest in long lived generation and storage assets in the WEM should be able to lock in a price at or near the gross CONE for a minimum of 15 years.	

Conceptual Design Proposal 13:

The current Availability Classes will be removed from the WEM Rules.

The RCM will allocate facilities to one of three Capability Classes.

CRC allocation methodologies will be amended to consider hybrid facilities as a single entity.

Capability Class 1 facilities will be required to demonstrate fuel arrangements that enable them to run for 14-hours, with this requirement practical implementation to be considered in stage 2 of the review.

Capability Class 1 facilities will be required to be available during all dispatch intervals, unless on an outage.

The proposed design for Capability Class 2 is outlined in design Proposal 14 and the design for Capability Class 3 will be developed in stage 2 of the RCM Review.

Consultation Questions

(13)(a): Do stakeholders support replacement of the current Availability Classes with Capability Classes?

Stakeholder	Stakeholder Feedback	EPWA's Response
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • Change Energy; • Perth Energy;	• Alinta Energy; • Collgar; • Shell Energy; and	• AEC; • ECP; • Synergy.
AEC	Supports, in principal, replacing the current Availability Classes with Capability Classes but suggests further consideration needs to be given to: • how co-located wind and solar projects will be considered for certification purposes and what Capability Class they will be assigned; and • potential unintended consequence of treating hybrid facilities as a single entity is that it may not create the 'correct' set of incentives for the facility and for the market. The AEC remains open minded about treating hybrid facilities as a single entity and also acknowledges that there are a range of challenges. The obligations and financial incentives for hybrid facilities need to balance the market requirements with how owners may prefer to operate their hybrid facilities. EPWA should also consider the following issues: • Will treating hybrid facilities as a single entity incentivise them to enter the market and assist with the energy transition? • Does this approach provide revenue sufficiency for hybrid facilities and allow them to operate using their preferred dispatch profile? • Does this create the 'right' set of incentives for facilities and the market? The proposed Capability Classes appear to group together different products, each of these products offer different reliability and value to the market, and it is inappropriate to price them similarly.	EPWA acknowledges the concerns raised by AEC and considers that, where a facility is capable of operating in either as a Capability Class 2 or as a Capability Class 3 facility, the participant will be able to opt for the class that best fits the preferred operational profile.

Stakeholder	Stakeholder Feedback	EPWA's Response
Synergy	Synergy is supportive of the replacement of the current Availability Classes with Capability Classes that consider the firmness as well as duration of supply at a high level. However, the details of the Capability Classes requires further assessment and refinement in stage 2 to ensure they are fit for purpose and encourage an appropriate mix of firmness and duration in the WEM. Additional consideration is also needed as to the appropriate technologies for each Capability Class.	Please refer to section 2.4 for additional considerations from stage 2 of the RCM Review. The detailed design will be developed in stage 3 of the RCM Review.
Consultation Questions **(13)(b):** Do stakeholders support the conceptual design proposal for the Capability Classes?		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • Alinta Energy; • Change Energy; • ECP; • Perth Energy; • Shell Energy; and • Synergy.		
Collgar	It is unclear that the priority order is needed given the price signals from the two reserve capacity products will incentivise investment in the 'right' facility types. Further, the prioritisation order is likely directly opposed to any new WEM objective to decrease carbon emissions. It may be appropriate for longer duration storage to be in Capability Class 1, using a performance-based approach.	EPWA considers that the priority order is needed because it recognises that facilities with firm availability provide a greater contribution to system reliability than those with lower availability. This approach reflects the intent of the RCM. If a long duration storage facility can satisfy the availability requirement of Capability Class 1 it will be assessed as a Capability Class 1 facility.
Enercloud	This may not feasibly cater for longer duration stress events. A greater focus not just on peak demand and ramping, but also on energy availability at all times is recommended, particularly for longer duration stress events	EPWA considers that the design of the new Capability Classes is specifically aimed at addressing long duration stress events i.e. the "duration gap" that is projected to emerge once baseload fossil fuel plant exits the WEM.
Perth Energy	Supports, in principle. Our hesitation relates to the 14-hour fuel obligation. Assuming that this remains unchanged then generators that cannot demonstrate that they meet this obligation can move from Capability Class 1 to Class 2.	

Stakeholder	Stakeholder Feedback	EPWA's Response
	Would these generators then only be required to be available within the Storage Obligation Duration window that is set for storage? It would be inequitable if generators were required to meet a higher obligation than storage systems. On the other hand, the gap in obligation between being available for four hours per day rather than continuously is substantial. If the 14-hour obligation is to be retained, then perhaps Capability Class 1 should have sub-categories.	In accordance with Review Outcome 10, Capability Class 2 facilities which consist solely of ESR components will continue to be assessed based on the linear derating method, which may have a different number of hours required. Proponents can request a five-year fixed availability duration requirement for an ESR facility. DSPs will continue to be assessed based on a 12-hour availability requirement. AEMO will forecast the availability duration gap based on the capacity of the existing and committed fleet, and will publish it in the ESOO, including forecasts for subsequent years. The WEM Rules will set metrics to identify if the duration gap is at risk of not being met in future years and require AEMO to monitor and publish these metrics. The Coordinator's reviews in WEM Rule 4.13B will include consideration of: • Availability duration gap metrics; and • Availability duration requirements for ESR and DSP facilities.
Shell Energy	Broadly, we are supportive however, we note that there may be inequity regarding obligations between classes. We have concern around the 14-hour fuel obligation and if this remains unchanged, a generator who cannot demonstrate they meet this obligation could move from class 1 to class 2. In these circumstances, would generators only be required to be available during the Storage Obligation Duration window set for storage and therefore inequitable if generators were required to meet a higher obligation than storage systems. Shell Energy requests clarification on this point if the 14-hour fuel obligation is retained.	
Synergy	Synergy supports the proposal for the capacity certification of hybrid facilities (intermittent + ESR) being further explored. The obligations and financial incentives for hybrid facilities need to align to the desired outcomes and also consider the preferred operational dispatch of the facility owners (i.e. will the ESR be "firming" the intermittent or will it provide peak energy and ESS). Synergy is of the view that the location of an ESR facility (i.e. co-located or stand-alone) should not be the determinant of the operational requirements for the ESR (e.g. does it "firm" an intermittent generator or does it provide energy and ESS) as there may be other drivers (such as network access, land availability, costs etc.) that influence the location	EPWA notes Synergy's considerations. The detailed design for assigning CRC to hybrid facilities will be developed and consulted on during Stage 3 of the RCM Review.

<table>
<tr><th>Stakeholder</th><th>Stakeholder Feedback</th><th>EPWA’s Response</th></tr>
<tr><td></td><td>decision of an ESR, and the facility owner should be able to choose what obligations apply.</td><td></td></tr>
<tr><td colspan="3">Consultation Questions
(13)(c): Do stakeholders support retaining the 14-hour fuel requirement, with its practical implementation to be considered in stage 2 of the review, and the all-hours availability requirement for Capability Class 1?</td></tr>
<tr><td colspan="3">The following stakeholders indicated that they ‘support’ or generally support the proposal:
• AEMO; and
• ECP.</td></tr>
<tr><td>Alinta Energy</td><td>Alinta Energy does not support.
We consider that:
• Unlike for the flexible product, the paper lacks adequate analysis justifying why 14- hour operation is required.
• As noted by the paper, the current requirement is based on an estimate of how much time is required on re-supply for distillate fuel – which we suggest is no longer relevant.
• The paper states that further consideration is required to determine the appropriate duration requirement for class 2 facilities. However, this analysis should inform the appropriateness of the 14-hour requirement as the key question is the same: ‘how much energy for how long is continuously required to maintain reliability?’ We suggest this answer should only have one answer and therefore one requirement.
• Maintaining this requirement may be extremely expensive, if not infeasible, as the gas market tightens due to further reserve downgrades
• These cost increases may necessitate a significant increase in the BRCP, noting:
  ○ the current method does not compensate the significant cost of reserving fuel capacity; and</td><td>The 14-hour requirement stems from AEMO’s implementation of the current Availability Class definitions in clause 4.11.4 of the WEM Rules. The WEM Procedure requires participants to demonstrate firm fuel availability for peak trading intervals (8am-10pm) on all business days. This procedure was reviewed and updated in December 2022, and the requirement was reconfirmed.
EPWA has considered the submissions and remains concerned that relaxing the requirement to show evidence that generation facilities have sufficient fuel to operate during periods of system stress would risk reducing the level of reliability provided for by the WEM Rules, and that doing so would be counter to one of the key principles of the RCM Review.
Recent fuel supply issues illustrate the importance of fuel availability and recent changes as part of the Market Power Mitigation Strategy mean that participants now have certainty that the costs of long-term take-or-pay fuel contracts can be reflected in market submissions.</td></tr>
</table>

Stakeholder	Stakeholder Feedback	EPWA's Response
	◦ If the BRCP does not cover these costs, generators would need to be permitted to recover them in the RTM and the price cap would need to significantly increase, noting that we expect generators would not recover these costs otherwise based on average run times. • Having two different availability requirements with similar payments for either would create an uneven playing field and result in generators abandoning class 1. • Only a few facilities would be required to meet either gap, especially for the full duration. Once a gap is filled, other facilities offering less than either 14 hours or the class 2 duration would not be contributing less to reliability, all else being equal. Consequently, further penalties for not meeting either duration (or incentives for the opposite) would present unnecessary costs. For example, if duration were considered a product like reserve capacity and flexible capacity – a lower price would be offered to avoid the total cost of the product bought continuing to increase.	The fundamental reason for having three Capability Classes is to recognise that facilities with firm availability provide a greater contribution to system reliability than those with lower availability. Participants who wish to procure shorter duration fuel contracts can instead seek certification in Capability Class 2 and receive a prorated CRC accordingly, with fuel availability obligations in fewer hours than faced by facilities in Capability Class 1. This will enable the participants to reduce their fuel contract costs. However, EPWA acknowledges that the current WEM Procedure may be more restrictive than is warranted to ensure fuel availability during times of system stress. The current WEM Procedure requires demonstrating fuel availability during the midday trough, when it is increasingly likely that the majority of the facilities will be dispatched down or off. In future, it will be more appropriate for the WEM Procedure to focus on the availability gap – the period over and after the peak demand– rather than periods in the middle of the day. EPWA considers that the WEM Rules could provide additional guidance on the implementation of the provisions in clause 4.11.4(a)ii such that AEMO should consider the time of day in which certification in Capability Class 1 requires firm fuel contracts, particularly as the overnight duration gap extends (see section 2.4.2). Offer obligations, testing requirements, and refund incentives will remain in place.
Perth Energy	Perth Energy does not support retaining this obligation. There are already two strong incentives for generators to ensure that they have access to sufficient fuel: • Having an adequate fuel supply is an integral part of ensuring that the plant can fulfil this primary revenue generating role; and • substantial refunds, and potential loss of capacity credits, that will be incurred through failure to meet capacity obligations.	See above response

Stakeholder	Stakeholder Feedback	EPWA's Response
	Perth Energy notes that it is coal fired plant operators, who are fully compliant with the 14-hour rule with long term contracts and substantial stockpile facilities, that are currently struggling to maintain fuel supply. There is also the practical issue of just what this clause actually means. AEMO appears to be interpreting it to mean that a generator has contracted fuel supply sufficient to run at maximum output for 14 hours each and every day. Further, that contract needs to be in place to cover the period up to three years in advance. This is totally impractical for a gas peaking plant, that may only be dispatched for a few hours a month to meet extreme supply-demand stress situations. It also ignores the realities of gas contracting in the current market. Perth Energy does not support retaining this obligation. However, if it is decided that this obligation is to be retained, Perth Energy suggests that this should not be an obligation to secure certification but should be demonstrated once the plant is in operation, perhaps at the same time that capacity testing is undertaken.	
AEC	The AEC does not support retaining the 14-hour fuel requirement. The AEC suggests that the 14-hour fuel requirement is not retained and instead replaced with a fuel requirement aligned with the initial intent of 4-5 hours a day.	See above.
Change Energy	Change Energy does not necessarily support retaining the 14-hour fuel requirement.	
Collgar	It is unclear that retaining the 14-hour fuel requirement is appropriate, further consideration of the availability duration for Capability Class 1 is needed to ensure that is not too onerous and/or exceeds what can be reasonable achieved by lower carbon technologies	
Shell Energy	Shell Energy encourages EPWA to consider the 14-hour fuel requirement given the current level of large and small scale intermittent generation on the SWIS, it is highly unlikely that a Scheduled	

Stakeholder	Stakeholder Feedback	EPWA’s Response
	Generator will be required for 14 consecutive hours to maintain reliability. Therefore, we are of the view that the current fuel requirement is excessive and this should be addressed through the RCM review to ensure that generators do not over-procure fuel and transport capacity at a significant cost to the market. We suggest that the 14-hour fuel requirement is not retained and instead replaced with a fuel requirement aligned with the initial intent of 4-5 hours a day.	
Synergy	Synergy strongly advocates that the 14-hour fuel obligation and its implementation is further assessed in stage 2 to ensure that the obligations and duration requirements placed on facilities in Capability Class 1 are reasonable. In addition, the revenues for Capability Class 1 need to be appropriate to encourage efficient investment in facilities that can provide firm, longer duration capacity, which will be increasingly important for reliability requirements in the WEM.	
Tesla	If no new parameters are planned, Tesla does not support the maintenance of a 14-hour availability requirement to qualify as firm, unrestricted capacity (with penalties for non-compliance). Additional analysis on system stress event duration is required to justify just an onerous threshold. For example, we recommend progressing a shorter requirement (e.g. 4 to 6 hours aligned with peak stress duration) with additional incentives for longer duration as it is deemed necessary. This is consistent with system stress analysis from the UK and US, also aligns with the ERA’s findings from its Effectiveness Review.	

Stakeholder	Stakeholder Feedback	EPWA's Response
Conceptual Design Proposal 14: AEMO will determine an availability duration requirement for new Capability Class 2 facilities, based on the capacity of the existing and committed fleet, and publish it in the ESOO, including forecasts for subsequent years. Capability Class 2 facilities will receive CRC equal to their maximum instantaneous output pro-rated by the number of hours they can sustain this output divided by the availability duration requirement. Proponents can request a five-year fixed availability duration requirement for a Class 2 facility but this request will only be accepted if the facility is needed to meet the reserve capacity target. **Consultation Questions** **(14)(a):** Do stakeholders support the proposal for AEMO to calculate the availability duration requirement for each capacity cycle?		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • ECP; • Synergy. • Alinta Energy; • Perth Energy; • Change Energy; • Shell Energy; and		
AEMO	While AEMO supports this design proposal, we note that significant further work is required to ensure that we can confidently determine an availability duration in the context of a system that is comprised of majority intermittent and storage facilities. Therefore, an availability duration will need to consider more than the overnight load and storage capability. AEMO suggests that guidance (informed by further modelling) is provided.	The detailed design will be developed and consulted on in Stage 3 of the RCM Review.
Alinta Energy	Support reviewing the appropriate availability duration but recommend: • If implemented, this duration requirement should replace the current fuel requirement (per the response to 13.4).	See responses above.
Change Energy	Support with concerns raised regarding proposed changes to clause 4.5.9(a)(ii).	See response to concerns raised by Change Energy above.
Collgar	Understands the policy intent however, this potential policy change creates investment uncertainty given different technologies are best	EPWA acknowledges the concern over a mismatch between the time/technical parameters that affect revenue and the

Stakeholder	Stakeholder Feedback	EPWA's Response
	placed to provide longer duration storage. Collgar recommends EPWA also considers other, market-based options.	expected life of an investment, particularly in relation to longer duration storage facilities. EPWA is examining this issue separately.
Perth Energy	Perth Energy supports the proposal that AEMO should set the duration requirement but that this should be in liaison with the ERA. Conceptual Design Proposal 10 suggests that storage will eventually become the lowest expected capital cost plant, so will be used by the ERA to set the BRCP.	EPWA has further considered the approach to setting the reference technology for the BRCP and has included a new proposal in Part 2 of this paper (see section 5.5).
Synergy	Synergy agrees that a separate Capability Class for lower duration firm capacity is required and that the duration requirement for this Capability Class should continue to be monitored by AEMO and amended as required. Synergy is of the view that further consideration is needed regarding how to best manage the changing duration to ensure that there continues to be a mix of durations that best match the requirements of the load shape. Ideally the SWIS would have a mix of duration ESRs that can be appropriately stacked to best match to the load shape.	See analysis of options in section 2.4.2.
Consultation Questions **(14)(b):** Do stakeholders support prorating the CRC for Capability Class 2 facilities in proportion to the availability duration requirement?		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • ECP; Perth Energy; and • Shell Energy.		
Alinta Energy	Further consideration of whether the duration target, once identified, would be better met outside the RCM, for example via an AEMO contract. We suggest that if the duration target can be met by a small subset of facilities via contracts (potentially long-term), then imposing penalties, incentives or higher universal duration requirements may	See analysis of options provided in section 2.4.2.

Stakeholder	Stakeholder Feedback	EPWA's Response
	impose unnecessary costs and barriers to entry for other forms of reserve capacity. Consideration of alternatives to time-based RCOQs that match the duration requirement, noting that the current requirements on storage may result in energy and ESS capacity being routinely withheld unnecessarily. Our suggestions include: permission to offer the entire capacity and have it exhausted during the RCOQ window, or RCOQs only on days where AEMO anticipates a need.	
AEC	The AEC suggests EPWA consider an approach where a mix of Class 2 facilities with different availabilities are stacked to meet the duration gap. There could be a combination of 2-hour, 4-hour and 8-hour facilities, and each would receive capacity payments based on the duration requirement and continue to dispatch according to an availability requirement fixed for the long-term. If priced appropriately, this would provide revenue and investment certainty, and encourage the entry of long duration facilities.	
Synergy	Synergy is of the view that further consideration is needed regarding how to best manage the changing duration. Ideally the SWIS would have a mix of duration ESRs that can be appropriately stacked to best match to the load shape. Synergy suggests that the design and obligations of Capability Class 2 requires further assessment and refinement in stage 2.	
Collgar	Understands the policy intent however, this potential policy change creates investment uncertainty given different technologies are best placed to provide longer duration storage. Collgar recommends EPWA also considers other, market-based options.	EPWA acknowledges the concern over a mismatch between the time/technical parameters that affect revenue and the expected life of an investment, particularly in relation to longer duration storage facilities. EPWA is examining this issue separately.

Stakeholder	Stakeholder Feedback	EPWA's Response
Consultation Questions **(14)(c):** Do stakeholders support allowing proponents to request a 5-year fixed availability requirement?		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; and • ECP.		
AEC	While the AEC supports a fixed availability duration for Capability Class 2 facilities to address this problem, a 5-year fixed availability requirement will not create enough certainty to promote investment in these generation types. The AEC suggests EPWA consider an approach where a mix of Class 2 facilities with different availabilities are stacked to meet the duration gap. Regardless of the approach, the AEC is opposed to proponents being required to request the fixed availability period and there being conditions on when proponents will be able to receive a fixed availability period. Measures to address revenue insufficiency and the lack of investment certainty should be encouraged by policy makers wherever possible.	In accordance with Review Outcome 10, Capability Class 2 facilities which consist solely of ESR components will continue to be assessed based on the linear derating method, which may have a different number of hours required. Proponents can request a five-year fixed availability duration requirement for an ESR facility. DSPs will continue to be assessed based on a 12-hour availability requirement. AEMO will forecast the availability duration gap based on the capacity of the existing and committed fleet, and will publish it in the ESOO, including forecasts for subsequent years. The WEM Rules will set metrics to identify if the duration gap is at risk of not being met in future years and require AEMO to monitor and publish these metrics. The Coordinator's reviews in WEM Rule 4.13B will include consideration of: • Availability duration gap metrics • Availability duration requirements for ESR and DSP facilities EPWA acknowledges the concern over a mismatch between the time/technical parameters that affect revenue and the expected life of an investment, particularly in relation to longer
Collgar	A five-year 'grandfathering' arrangement will likely not address this uncertainty and this same five-year period has not been applied in calculating the BRCP. Collgar recommends EPWA also considers other, market-based options.	
Perth Energy	Class 2 facilities should be able to request a fixed availability requirement, but we do not believe that five years is sufficient.	
Shell Energy	Supportive of allowing proponents to request a fixed availability requirement, however considers that the duration is insufficient and request EPWA to consider a longer duration	

Stakeholder	Stakeholder Feedback	EPWA's Response
Change Energy	Change Energy does not support this proposal, any long term commitments made by AEMO should be consistent across Capability Classes.	duration storage facilities. EPWA is examining this issue separately.
Synergy	The proposal to provide a level of certainty to ESR facilities on the duration by effectively "locking in" the duration requirement for a five-year period appears appropriate. Synergy disagrees with the "lock-in" ability being tied to the capacity surplus position at the time of certification and suggest that all ESR's should be able to "lock-in" the duration requirement applicable at the time of certification. Synergy is of the view that further consideration is needed regarding how to best manage the changing duration.	EPWA considers that arrangements to fix the duration requirement should only be available to new facilities that are needed to meet the RCR. The primary purpose of the RCM is to ensure system reliability for the benefit of consumers. Allowing facilities that are not needed to fix the availability requirement would come at a cost for consumers without providing adequate benefit.

Conceptual Design Proposal 15:

CRC allocation will remain on an ICAP basis, with refunds payable for any forced outage.

The reserve margin in the first limb of the Planning Criterion will be set at the greater of the fleet-wide EFORd and the largest contingency expected at system peak, with AEMO assessing both each year.

Where, over a three-year period, a facility has an EFORd higher than 10%, AEMO will be required to reduce its CRC by the EFORd.

The method for calculating EFORd will also account for forced outages reported at times the relevant facility had not been called to run.

A facility whose CRC has been reduced under clause 4.11.1(h) will be excluded from the calculation of fleet outage rate for the purposes of setting the planning criterion reserve margin.

Consultation Questions

15(a): Do stakeholders support continuing to allocate CRC on an ICAP basis?

The following stakeholders indicated that they 'support' or generally support the proposal:

- AEMO;
- Alinta Energy;
- Change Energy;
- Perth Energy;
- Collgar;
- ECP;
- Shell Energy; and
- Synergy.

Consultation Questions

(15)(b): Do stakeholders support the conceptual design proposal for treatment of outages?

Stakeholder	Stakeholder Feedback	EPWA's Response
The following stakeholders indicated that they 'support' or generally support the proposal: • Change Energy; • Collgar; • ECP; and • Shell Energy.		
AEMO	AEMO recommends being provided with discretion (to be outlined in a WEM Procedure) in relation to the reduction in CRC for facilities with an EFORd higher than 10%, noting that in some cases outages may be a result of exceptional circumstances (e.g. a very unusual weather event), which would not reasonably be expected to present a risk to the capacity provider's ability to provide CRC into the future.	Under Review Outcome 14, AEMO will not be required to reduce CRC for a facility with an EFORd greater than 10% if it has evidence that the underlying reasons for the high outage rate have been resolved.
AEC	The AEC does not support this approach because: • It could disproportionately penalise a facility that had a forced outage in the past but has since permanently fixed the problem; • The forced outages could have occurred in periods outside system stress events and not impacted the ability to meet peak demand; • It disadvantages facilities that operate more frequently; The fault could have been resolved years ago but this change will mean that a facility's CRC will be reduced in the future. This will have a significant long-term impact for the revenue of the facility despite the problem being fixed and may lead to early retirements. AEMO should have some discretion, as is currently the case, in considering whether a facility's CRC should be adjusted where their forced outage rate exceeds the threshold.	
Alinta Energy	Alinta Energy is neutral. If implemented, we suggest AEMO retain some discretion and transitional measures may be required. While we recognise the intent, we suggest that the benefit of this proposal in terms of increasing generator availability may be limited noting that generators with higher outage rates tend to be those that run more often – i.e. mid-merit or baseload plant – and therefore	

Stakeholder	Stakeholder Feedback	EPWA's Response
	already have the highest incentives to be available (assuming no other external factors like coal supply restrictions). Reforms to outage quantities may also be required to avoid over-reporting which occurs as outages must be reported as the difference between available generation and maximum capacity. If implemented, a transitional approach to accounting for outages may need to be undertaken due to the differing interpretations of outage reporting by participants and the over-reporting issues identified above. This would be a similar approach to the Scheduled Generator availability reforms where the Refund Exempt Planned Outage Count set outages prior to 1 June 2016 to zero. Finally, some consideration may need to be given to the interaction with the NAQ regime.	
Perth Energy	We understand the motive behind the threat of losing capacity credits if forced outages exceed a certain target, but note that as a performance motivator, it is third in line behind the incentives of lost revenue and reserve capacity refunds. As such, while it is a weak driver of behaviour for an operational perspective, it is still perceived by investors and bankers as a significant investment risk. As such, it is actually a disincentive for the installation of adequate reserve capacity. The Paper states that the details of the capacity credit reduction process will be considered in Stage 2. As part of this review, we ask that EPWA notes the significant impact on plant maintenance caused by COVID restrictions preventing technical support staff coming to WA. The past two years are not a good indication of likely plant performance without these restrictions in place and suggest that the pre-COVID experience is more relevant.	While EPWA agrees that CRC allocation should be based on the expected future ability of a facility to provide capacity, it considers that it is necessary to strengthen the CRC derating requirements in clause 4.11.1(h). EPWA accepts that the historical outage rate may not represent expected future outage rate, and will include some discretion for AEMO to not apply the derating if it is satisfied that the underlying reason for the outage has been addressed.
Synergy	Synergy does not support the proposed changes to clause 4.11.1 to require AEMO to reduce the CRC for facilities with higher outage rates than the level prescribed within the clause. The certification process for capacity is forward looking and should therefore allow consideration of expected performance in the future. Synergy does not consider that	

<table>
<tr><th>Stakeholder</th><th>Stakeholder Feedback</th><th>EPWA’s Response</th></tr>
<tr><td></td><td>being prescriptive under this clause provides benefits to the market and may unintentionally lead to future over procurement of capacity.</td><td></td></tr>
<tr><td colspan="3">Conceptual Design Proposal 16:
To ensure independent estimates of intermittent generator output, AEMO will procure expert reports to derive estimates of performance on behalf of participants.
Consultation Question (16): Do stakeholders support requiring AEMO to procure expert reports on behalf of participants?</td></tr>
<tr><td colspan="3">The following stakeholders indicated that they ‘support’ or generally support the proposal:
• Change Energy; and
• ECP.</td></tr>
<tr><td>AEMO</td><td>AEMO agrees that procurement of consultants will provide for some independence in the process, although we note that some data and other inputs will continue to be required from the proponent, with some inevitable limitations on the quality assurance that can be undertaken by the consultant and AEMO.
We also note the following matters for further consideration and look forward to working with EPWA and industry in Stages 2 and 3 of the RCM Review to achieve an appropriate scheme design:
• any implications for the timeframes in determining Certified Reserve Capacity;
• procurement practices required to ensure AEMO meets industry expectations of value for money; and
• payment arrangements for the independent reports. Consistent with the Cost Allocation Review objective, AEMO supports a causer-pays approach.</td><td rowspan="2">EPWA has amended the proposed approach based on the feedback received. See Review Outcome 12.</td></tr>
<tr><td>Alinta Energy</td><td>Alinta Energy does not support the proposal.
• The data in the chart does not appear to reliably support that there are significant declines in the first 5 years of their operation.
• We suggest a key reason why the CRC of intermittent generators could decline ‘over the first five years of their operation’ is that</td></tr>
</table>

Stakeholder	Stakeholder Feedback	EPWA's Response
	under the current RLM, new generators have an advantage in that their output does not impact the timing of peak LSG intervals until they are operational. This advantage (and subsequent decline) would be more pronounced for larger generators, as their relatively larger output is incorporated and shifts peak LSG intervals to when they are less productive. This was identified by ERA's RLM report (p. 29). If the proposal is implemented despite these considerations, we strongly recommend a procedure be drafted to: • Permit proponents to interrogate and approve the quality of the data and the key assumptions of the report as well as the outcomes from the report prior to finalising. Reports are key to supporting investment decisions and without adequate access, investors face greater risk and uncertainty. • Ensure AEMO appropriately manages costs and potential conflicts of interest. • Manage any disputes.	
AEC	The AEC does not support AEMO procuring expert reports on behalf of participants	
Collgar	Collgar does not support AEMO procuring expert reports on behalf of Market Participants. While Collgar understands the policy intent, there are several practical considerations limiting the suitability of this approach. Collgar suggests that a more practical approach would be for AEMO to discuss any material deviations from the expert report and actual performance directly with the Market Participant. This would be more cost effective and directly targeted at the addressing the perceived problem.	
Perth Energy	Perth Energy does not support the proposal. The expert report is a critical part of the project development, approval and financing process. An investor needs to be fully confident in their	

Stakeholder	Stakeholder Feedback	EPWA's Response
	consultant which, in turn, requires careful assessment of the potential service providers. We question whether AEMO has the competency, or the underlying level of incentive, to undertake this work. It would also place AEMO in a difficult legal position should the expert's work subsequently be challenged as having led to an "incorrect" investment decision. Figure 24 in the Paper does indicate that the expert reports are not necessarily a good guide to future wind farm output. It is hard to say whether this is due to inadequate data or over optimism on the experts' part or just the complexity in estimating output in the face of climate change impacting weather and wind patterns. If it is the latter, then a consultant appointed by AEMO is no more likely to get an "accurate" result than anyone else.	
Shell Energy	Shell Energy does not support AEMO procuring expert reports on behalf of participants. • Investors require a high level of confidence in the consultants who are developing the expert reports. There would need to be a rigorous process for assessment and engagement of consultants. • If AEMO was to procure the expert reports, the cost of the procurement would not be equitable as AEMO do not have the same financial drivers as investors. • There is nothing to suggest that if AEMO were to procure expert reports, that these reports would be more 'accurate'. There is a risk that a participant may not meet the CRC application deadline if a consultant failed to prepare the expert report within the required timeframe. Is AEMO liable in this circumstance?	
Synergy	Synergy is of the view that the proposal for AEMO to procure expert reports on behalf of intermittent facilities is unnecessary and notes that there may be unintended complexities, including creating an unintended bias in the capacity certification process for intermittent generation. The variations in the CRC outcomes in the early years are	

Stakeholder	Stakeholder Feedback	EPWA's Response
	likely to be caused by factors other than the choice of experts, noting that the methodology itself is likely to be driving these outcomes.	
Conceptual Design Proposal 17: The methodology to assign CRC to facilities in each of the different Capability Classes will differ by class as follows: • Class 1: Expected output at projected 10% POE peak ambient temperature; • Class 2: Expected output at projected 10% POE peak ambient temperature, adjusted for required availability duration; and • Class 3: To be confirmed in stage two of the RCM review. **Consultation Questions** **(17)(a):** Do stakeholders support using a different methodology to assign CRC to facilities in each Capability Class.		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • Collgar; • ECP; • Perth Energy; and • Shell Energy.		
Change Energy	Change Energy considers the methodology to assign CRC to facilities should be considered as a whole. On this basis, we strongly recommend decisions on Class 1 and 2 methodologies should be delayed and considered holistically with Class 3 and the IRCR to ensure it works as a package.	EPWA has considered all methods for assigning CRC to facilities in the Capability Classes 1 to 3 in Stage 2 of the RCM Review together with the method for determining the IRCR. EPWA considers that all three methods work as a package.
Consultation Questions **(17)(b):** Do stakeholders support the proposed methodology to assign CRC to facilities in Capability Class 1?		
The following stakeholders indicated that they 'support' or generally support the proposal: • AEMO; • Collgar; • ECP; and • Perth Energy.		
Alinta Energy	Alinta Energy does not support the proposal. Alinta Energy does not support using 10% POE peak ambient temperature for classes 1 and 2 because:	In Stage 2 of the RCM Review EPWA has considered the proposed approach based on the feedback received in submissions.

Stakeholder	Stakeholder Feedback	EPWA's Response
	• The paper does not justify this requirement: it states that the reference temperature may no longer be appropriate (without presenting analysis or a problem statement) and that this will be considered in stage 2 of the review. Despite this, it proposes a 10% POE forecast regardless, prior to this consideration. • There may not be an issue for the 10% POE requirement would resolve. Per AEMO's ESOO peak demand is occurring increasingly later than the peak temperature (and peak underlying demand) due to rooftop PV (p. 41-43.) For example, the highest demand days during 2022 all occurred after temperature had peaked and had dropped below 40°C (see figure 12). EVs may continue this trend. • Data on plant capability at the 10% POE peak temperature forecast may be very limited, producing inconsistent and inaccurate CRC assignments. • Increasing the maximum ambient temperature unnecessarily would impose avoidable costs on customers by decreasing the level of CRC assigned, increasing the reserve capacity price and necessitating further investments.	Capability Class 1 capacity will be assigned CRC based on its expected maximum output at 41 degrees. See Review Outcome 9.
Synergy	Synergy seeks clarity as to the reasoning for the proposed change to the methodology for CRC to expected output "at projected 10% POE peak ambient temperature" rather than the current "at 41oC".	
AEC	Yes. However, further to the above response to 13(c), the AEC does not support retaining the 14-hour fuel requirement for Capability Class 1 facilities.	See responses to issues raised in response to Consultation Question (13)(c) above.
Shell Energy	Shell Energy is supportive of the proposed methodology however, we do not support retaining the 14-hour fuel requirement for Capability Class 1 facilities.	
Change Energy	Change Energy considers the methodology to assign CRC to facilities should be considered as a whole. On this basis, we strongly	See response to the issue raised by Change Energy above.

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<tr><th>Stakeholder</th><th>Stakeholder Feedback</th><th>EPWA's Response</th></tr>
<tr><td></td><td>recommend decisions on Class 1 and 2 methodologies should be delayed and considered holistically with Class 3 and the IRCR to ensure it works as a package.</td><td></td></tr>
<tr><td colspan="3">Consultation Questions
(17)(c): Do stakeholders support the proposed methodology to assign CRC to facilities in Capability Class 2?</td></tr>
<tr><td colspan="3">The following stakeholders indicated that they ‘support’ or generally support the proposal:
• AEMO;
• Collgar;
• ECP; and
• Shell Energy.</td></tr>
<tr><td>AEC</td><td>AEC considers that each product should receive a capacity price based on their reliability and value to the market. Additionally, further to the above response to 14(a)(b)(c), Class 2 facilities could be separated based on their availability duration and receive a different capacity price.</td><td>See analysis of options provided in section 2.4.2.</td></tr>
<tr><td>Change Energy</td><td>Change Energy considers the methodology to assign CRC to facilities should be considered as a whole. On this basis, we strongly recommend decisions on Class 1 and 2 methodologies should be delayed and considered holistically with Class 3 and the IRCR to ensure it works as a package.</td><td>See above.</td></tr>
<tr><td>Perth Energy</td><td>The term “required availability duration” needs to be defined. For a facility that has limited fuel availability it would be equitable for this period to be the same as for a storage system, currently four hours. However, this is a substantial reduction on the Class 1 obligation and may not be optimal for the power system.</td><td rowspan="2">See analysis of options in section 2.4.2.
In accordance with Review Outcome 10, Capability Class 2 facilities which consist solely of ESR components will continue to be assessed based on the linear derating method, which may have a different number of hours required. Proponents can request a five-year fixed availability duration requirement for an ESR facility.
DSPs will continue to be assessed based on a 12-hour availability requirement.</td></tr>
<tr><td>Shell Energy</td><td>Supportive of the proposed methodology for Capability Class 2 facilities, however, as detailed above at 14(a)(b) and (c), we suggest that CRC for Class 2 facilities be proportionate to the availability duration requirement.</td></tr>
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Stakeholder	Stakeholder Feedback	EPWA's Response
		AEMO will forecast the availability duration gap based on the capacity of the existing and committed fleet, and will publish it in the ESOO, including forecasts for subsequent years. The WEM Rules will set metrics to identify if the duration gap is at risk of not being met in future years and require AEMO to monitor and publish these metrics.
Tesla	More clarity is required on how availability of storage technologies will be assessed, given historic fuel requirements are no longer relevant as we transition to renewables and storage.	See above.
Consultation Questions **(17)(d):** Do stakeholders prefer one of the three identified methodologies for assigning CRC to facilities in Capability Class 3 and what are the reasons for the preference?		
Alinta Energy	Our preferred method is the un-amended hybrid. The delta method and amended hybrid method risk producing implausible and volatile results as their sample size can be as few as three observations over a 7-year sample period. We consider that the latter would also expose the total fleet value to diminishing returns from new entrants and undervalue generators that shift peak LSG periods from peak demand periods – key pitfalls identified in ERA's RLM report. Alinta Energy strongly recommends that the un-amended hybrid method should be included in the options modelled. (More extensive comments are in the submission)	EPWA has undertaken substantial additional analysis and has developed a method for assigning CRC to facilities in Capability Class 3 in consultation with the RCMRWG and the MAC. See Review Outcome 11 and section 2.4.3 of the Information Paper.
AEC	The AEC is concerned that the three identified methodologies in the Consultation Paper do not reflect the preferred approach of many participants. The Consultation Paper indicates that EPWA will be undertaking further modelling and quantitative analysis of the methods. The AEC strongly encourages EPWA to include the hybrid method (without EPWA amendments) in the modelling so that it can be compared with the three methods included in the Consultation Paper.	

Stakeholder	Stakeholder Feedback	EPWA's Response
Collgar	Collgar agrees that the current RLM does not appropriately assess performance in system stress periods and that its deficiencies will be accentuated. Collgar also agrees with the principles an allocation method ought to demonstrate. Collgar does not support EPWA's proposed amendments to the Hybrid method. In practice, there is a trade-off between the method that captures the few most peak/system stress events and ensuring that volatility over time is minimised to provide sufficient certainty to support investment. A method that uses too few intervals will not only be more volatile, but also places too much weighting on individual events and is therefore not a good reflection of facility performance in periods of system stress (sample size is too low for meaningful statistical analysis). The nature of the original Hybrid calculation method maintains CRC allocation to existing generators when new facilities enter (the size of the fleet CRC appropriately increases), marginally increasing as scheduled generation retires and intermittent facilities make a greater contribution to meeting system demand. In contrast, the Delta and most notably Hybrid-EPWA methods decrease the allocation to existing intermittent facilities as new facilities enter. This is not aligned with the purpose of the RCM, as it neither appropriately compensates facilities for their capacity nor supports investment in said capacity. Both are needed to ensure that capacity is developed and available when required. Collgar also emphasises the need to have a new method to allocate CRC to intermittent facilities in place as soon as possible, that should also be used to allocate NAQs.	
ECP	it is important to ensure the methodology for certifying and allocating capacity credits to intermittent generators which Energy Policy WA is developing reflects their contribution to system reliability and provides strong incentives to firm up their capacity.	

Stakeholder	Stakeholder Feedback	EPWA's Response
Perth Energy	Perth Energy's preference is for an arrangement that provides a consistent evaluation of CRC for Capability Class 3 facilities as this is more likely to facilitate investment through reducing risk. The hybrid approach suggested by Collgar appears to be the most suitable and we would like to see this investigated further. We also strongly favour protecting the CRC of existing facilities, to minimise investor risk, and do not support an approach where newer plant takes CRC from existing facilities	
Shell Energy	supportive of using a different methodology and consider that the current RLM does not appropriately assess performance and as we move through the energy transition, and more intermittent generators enter the market, the inadequacies will be more pronounced, and the current methodology will no longer be fit for purpose. Therefore, Shell Energy would like to see the alternative methodologies explored, and we welcome further modelling and quantitative analysis in consultation with the relevant working groups and Market Participants.	
Synergy	Synergy supports replacing the current RLM and agrees that the new methodology should seek to: • reflect the expected dispatch in system stress periods; • incentivise locational diversity for new projects; and • minimise year on year volatility in CRC values to provide investment certainty. the methodology should attempt to limit the impact of future facilities on the CRC for existing intermittent generation, noting that NAQ regime and the CRC methodology should work together to encourage intermittent generation to locate in network locations that provide the best value to the WEM. Synergy is of the view that large volatility in the CRC values is unlikely to be beneficial to the market.	

Stakeholder	Stakeholder Feedback	EPWA’s Response
	Synergy acknowledges that a balance is needed to ensure that the methodology provides valid estimates of future facility performance while also minimising CRC volatility, and notes that the use of average/median annual data in preference to a value determined using the whole period better achieves this balance. Synergy is of the view that the original “hybrid method” using annual ELCC numbers appears to better achieve the desired outcomes for the methodology. Synergy encourages EPWA and the RCMRWG to continue working on the CRC methodology for intermittent generation in stage 2 of the RCM Review.	

Appendix B. CRC Allocation for Facilities in Capability Class 3

Volatility in generation output is the primary driver of volatility in CRC allocations to intermittent generators under the new method outlined in review outcome 12. Figure 23 shows historical output of the fleet of intermittent generators in the highest demand intervals and the current IRCR intervals:[32]

- fleet output in high demand intervals varies significantly between years;
- fleet output varies significantly between high demand intervals;
- the year with best performance in the highest demand intervals is the year with lowest peak demand; and
- IRCR intervals are, in some cases, significantly different from the peak demand intervals.

Figure 23: Intermittent Generation Fleet Output in Peak Demand Intervals

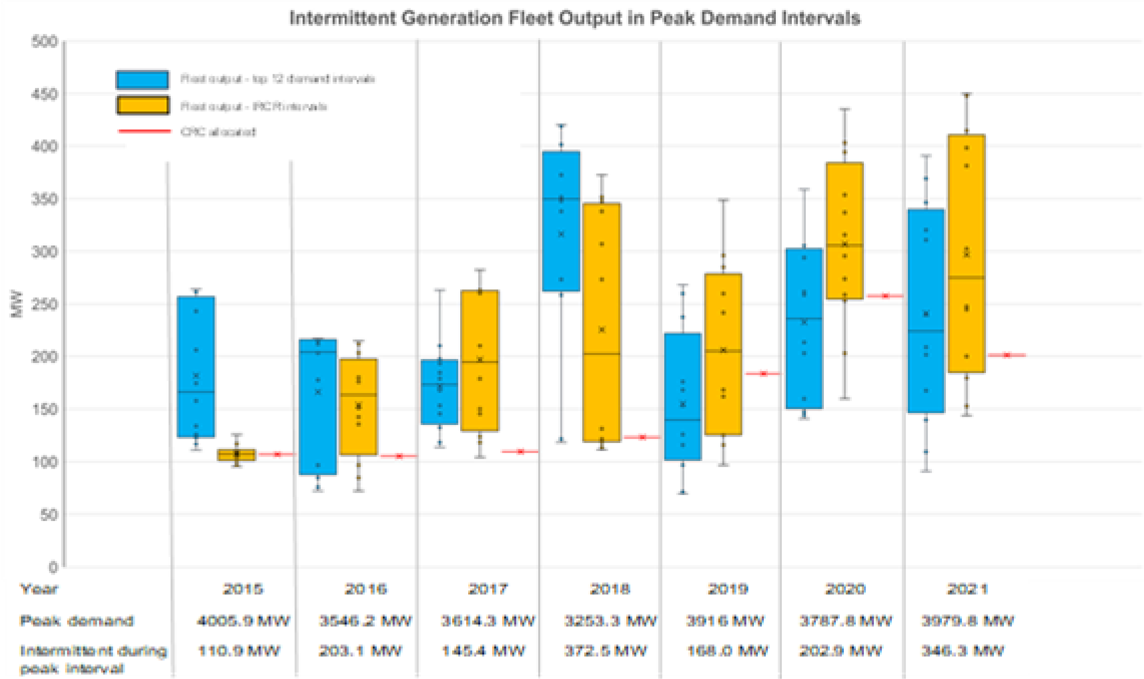

Table 17 shows an example of what indicative CRC results might have looked like for existing intermittent facilities in historical years if the new proposed method for setting IRCR intervals (see proposal B) had been in place.

32 Whiskers show maximum and minimum fleet performance in the relevant intervals, circles show other data points. Boxes show 25th and 75th percentile range, with a line across for the median. Crosses show the mean output.

Table 17: Indicative Facility CRC using the Proposed Allocation Method[33]

Facility	Nameplate capacity (MW)	2015-2019 (excluding 2018)[34]		2016-2020 (excluding 2018)[35]	
		Proposed IRCR Intervals (MW)	2021 CC (MW)	Proposed IRCR intervals (MW)	2022 CC (MW)
ALBANY_WF1	21.6	10.5	5.3	10.5	5.5
ALINTA_WWF	89.1	17.6	17.2	17.1	15.5
AMBRISOLAR_PV1	0.96	0.2	0.2	0.2	0.2
BADGINGARRA_WF1	130	27.5	26.6	25.1	26.2
BIOGAS01	2	0.2	1.2	0.2	0.8
BLAIRFOX_BEROSRD_WF1	9.3	0.0	0.0	0.0	0.0
BLAIRFOX_KARAKIN_WF1	5	0.3	0.5	0.2	0.5
BREMER_BAY_WF1	0.6	0.3	0.2	0.2	0.2
DCWL_DENMARK_WF1	1.44	0.7	0.4	0.6	0.4
EDWFMAN_WF1	80	10.4	16.2	10.1	14.7
GRASMERE_WF1	13.8	7.1	3.7	7.2	3.9
GREENOUGH_RIVER_PV1	40	4.1	7.4	3.5	6.4
HENDERSON_RENEWABLE_IG1	3	1.1	1.6	1.1	1.6
INVESTEC_COLLGAR_WF1	206	39.0	15.8	41.5	21.8
KALBARRI_WF1	1.6	0.2	0.3	0.2	0.2
MERSOLAR_PV1	100	25.4	16.3	22.4	13.7
MWF_MUMBIDA_WF1	55	12.1	7.0	12.1	7.0
NORTHAM_SF_PV1	9.8	1.5	1.8	1.3	1.6
RED_HILL	3.6	2.0	2.8	1.9	2.8
ROCKINGHAM	4	1.6	2.3	1.5	2.2
SKYFRM_MTBARKER_WF1	2	0.9	0.5	0.9	0.6
SOUTH_CARDUP	4.2	2.2	3.0	2.0	2.9
TAMALA_PARK	4.8	3.0	4.4	2.9	4.3
WARRADARGE_WF1	180	35.9	30.2	34.2	30.2
YANDIN_WF1	214.2	51.6	36.2	46.6	34.1

33 Fleet ELCC based on an EUE target of 0.0002%.

34 Fleet ELCC 255.61 MW.

35 Fleet ELCC 243.65 MW.

Appendix C. IRCR Interval Selection for Historic Years

C.1 Interval Selection for Previous Years – Peak IRCR

Section 3.2.3 included an example of the proposed IRCR selection method applied to the 2017 Capacity Year. This section compares the IRCR intervals selected by the method proposed under proposal B against the current method for the Capacity Years 2015-2021.

Table 18: 2015 IRCR intervals – Current vs Proposed

Date	Time	SOG (MW)	New Intervals	Current Intervals
8/02/2016	4:30 pm	3978.4	✓	✓
8/02/2016	5:00 pm	3990.3	✓	✓
8/02/2016	5:30 pm	3995.0	✓	✓
8/02/2016	6:00 pm	3942.3	✓	
8/02/2016	6:30 pm	3920.7	✓	
9/02/2016	4:30 pm	3889.4	✓	✓
9/02/2016	5:00 pm	3886.3	✓	✓
9/02/2016	5:30 pm	3860.6	✓	✓
10/02/2016	4:30 pm	3776.5		✓
10/02/2016	5:00 pm	3772.8		✓
10/02/2016	5:30 pm	3759.3		✓
14/03/2016	4:00 pm	3934.8	✓	
14/03/2016	4:30 pm	3990.0	✓	✓
14/03/2016	5:00 pm	3966.0	✓	✓
14/03/2016	5:30 pm	3967.3	✓	✓
14/03/2016	6:00 pm	3926.7	✓	
14/03/2016	6:30 pm	3948.4	✓	
14/03/2016	7:00 pm	3941.2	✓	

Table 19: 2016 IRCR Intervals – Current vs Proposed

Date	Time	SOG (MW)	New Intervals	Current Intervals
21/12/2016	3:30 pm	3474.5	✓	
21/12/2016	4:00 pm	3482.6	✓	
21/12/2016	4:30 pm	3496.9	✓	✓
21/12/2016	5:00 pm	3515.8	✓	✓
21/12/2016	5:30 pm	3503.5	✓	✓
21/12/2016	6:00 pm	3431.7	✓	
4/01/2017	4:00 pm	3337.4		✓
4/01/2017	4:30 pm	3345.2		✓
4/01/2017	5:00 pm	3339.2		✓
1/03/2017	4:00 pm	3431.3	✓	
1/03/2017	4:30 pm	3504.2	✓	✓
1/03/2017	5:00 pm	3512.4	✓	✓
1/03/2017	5:30 pm	3509.9	✓	✓
1/03/2017	6:00 pm	3459.7	✓	
1/03/2017	6:30 pm	3436.4	✓	
3/03/2017	4:00 pm	3315.2	✓	✓
3/03/2017	4:30 pm	3347.6	✓	✓
3/03/2017	5:00 pm	3329.4	✓	✓

Table 20: 2017 IRCR Intervals – Current vs Proposed

Date	Time	SOG (MW)	New Intervals	Current Intervals
15/02/2018	5:00 pm	3172.2		✓
15/02/2018	5:30 pm	3195.6		✓
15/02/2018	6:00 pm	3164.6		✓
12/03/2018	5:30 pm	3247.8	✓	✓
12/03/2018	6:00 pm	3251.5	✓	✓
12/03/2018	6:30 pm	3248.6	✓	✓
13/03/2018	3:30 pm	3380.7	✓	
13/03/2018	4:00 pm	3451.6	✓	
13/03/2018	4:30 pm	3536.1	✓	
13/03/2018	5:00 pm	3585.6	✓	✓
13/03/2018	5:30 pm	3609.5	✓	✓
13/03/2018	6:00 pm	3565.7	✓	✓
13/03/2018	6:30 pm	3561.2	✓	
13/03/2018	7:00 pm	3552.5	✓	
13/03/2018	7:30 pm	3496.0	✓	
13/03/2018	8:00 pm	3373.5	✓	
21/03/2018	4:30 pm	3343.6	✓	✓
21/03/2018	5:00 pm	3382.1	✓	✓
21/03/2018	5:30 pm	3360.2	✓	✓

Table 21: 2018 IRCR Intervals – Current vs Proposed

Date	Time	SOG (MW)	New Intervals	Current Intervals
20/01/2019	5:30 pm	3157.9	✓	✓
20/01/2019	6:00 pm	3159.7	✓	✓
20/01/2019	6:30 pm	3130.3	✓	✓
7/02/2019	4:30 pm	3163.1	✓	
7/02/2019	5:00 pm	3201.2	✓	
7/02/2019	5:30 pm	3255.6	✓	✓
7/02/2019	6:00 pm	3249.3	✓	✓
7/02/2019	6:30 pm	3217.0	✓	✓
7/02/2019	7:00 pm	3158.9	✓	
7/02/2019	7:30 pm	3183.9	✓	
8/02/2019	5:00 pm	3155.2	✓	✓
8/02/2019	5:30 pm	3192.8	✓	✓
8/02/2019	6:00 pm	3182.2	✓	✓
4/03/2019	5:00 pm	3157.3	✓	✓
4/03/2019	5:30 pm	3186.7	✓	✓
4/03/2019	6:00 pm	3168.1	✓	✓

Table 22: 2019 IRCR Intervals – Current vs Proposed

Date	Time	SOG (MW)	New Intervals	Current Intervals
12/12/2019	5:30 pm	3588.2	✓	✓
12/12/2019	6:00 pm	3571.0	✓	✓
12/12/2019	6:30 pm	3549.7	✓	✓
3/02/2020	5:30 pm	3554.5	✓	✓
3/02/2020	6:00 pm	3577.4	✓	✓
3/02/2020	6:30 pm	3596.6	✓	✓
4/02/2020	4:00 pm	3602.2	✓	
4/02/2020	4:30 pm	3719.2	✓	
4/02/2020	5:00 pm	3828.1	✓	
4/02/2020	5:30 pm	3918.8	✓	✓
4/02/2020	6:00 pm	3902.6	✓	✓
4/02/2020	6:30 pm	3901.9	✓	✓
4/02/2020	7:00 pm	3872.7	✓	
4/02/2020	7:30 pm	3873.6	✓	
4/02/2020	8:00 pm	3818.9	✓	
4/02/2020	8:30 pm	3701.3	✓	
14/02/2020	5:00 pm	3546.3		✓
14/02/2020	5:30 pm	3575.6		✓
14/02/2020	6:00 pm	3537.2		✓

Table 23: 2020 IRCR Intervals – Current vs Proposed

Date	Time	SOG (MW)	New Intervals	Current Intervals
23/12/2020	5:30 pm	3575.3	✓	✓
23/12/2020	6:00 pm	3608.1	✓	✓
23/12/2020	6:30 pm	3618.2	✓	✓
23/12/2020	7:00 pm	3558.8	✓	
24/12/2020	5:00 pm	3501.7	✓	✓
24/12/2020	5:30 pm	3546.2	✓	✓
24/12/2020	6:00 pm	3490.8	✓	✓
8/01/2021	4:30 pm	3652.7	✓	
8/01/2021	5:00 pm	3695.3	✓	
8/01/2021	5:30 pm	3778.8	✓	✓
8/01/2021	6:00 pm	3788.8	✓	✓
8/01/2021	6:30 pm	3731.0	✓	✓
8/01/2021	7:00 pm	3636.4	✓	
8/01/2021	7:30 pm	3595.6	✓	
8/01/2021	8:00 pm	3571.2	✓	
23/02/2021	5:00 pm	3473.4		✓
23/02/2021	5:30 pm	3536.4		✓
23/02/2021	6:00 pm	3501.0		✓

Table 24: 2021 IRCR Intervals – Current vs Proposed

Date	Time	SOG (MW)	New Intervals	Current Intervals
19/01/2022	5:30 pm	3950.8	✓	✓
19/01/2022	6:00 pm	3984.2	✓	✓
19/01/2022	6:30 pm	3976.3	✓	✓
21/01/2022	5:30 pm	3939.6	✓	✓
21/01/2022	6:00 pm	3952.6	✓	✓
21/01/2022	6:30 pm	3952.0	✓	✓
3/02/2022	6:00 pm	3958.9	✓	✓
3/02/2022	6:30 pm	3970.0	✓	✓
3/02/2022	7:00 pm	3906.0	✓	✓
14/02/2022	5:30 pm	3931.3	✓	
14/02/2022	6:00 pm	3940.8	✓	
14/02/2022	6:30 pm	3889.0	✓	
15/02/2022	5:30 pm	3949.8	✓	
15/02/2022	6:00 pm	3940.2	✓	
15/02/2022	6:30 pm	3890.8	✓	
16/02/2022	5:30 pm	3956.5	✓	✓
16/02/2022	6:00 pm	3971.6	✓	✓
16/02/2022	6:30 pm	3956.6	✓	✓

C.2 Interval Selection for Previous years – Flexible IRCR

This section shows the flexible IRCR intervals selected by using the method proposed in Proposal F for each of the Capacity Years 2015-2021.

The following must be noted when reading the tables:

- the interval with the highest ramp in each 4-hour period is shown with the total sent out MW highlighted in red font;
- The ramp rate (MW) is the difference between the total sent out between the first and the last interval of the 4-hour period; and
- The Trading Intervals in red font are high ramp periods experienced in the morning.

Table 25: 2015 Flexible IRCR Intervals – Proposed Method

Trading Interval	SOG (MW)	4 Hour Ramp Rate (MW)
2016-07-13 14:00:00	2169.0	
2016-07-13 14:30:00	2199.1	
2016-07-13 15:00:00	2258.0	
2016-07-13 15:30:00	2324.3	
2016-07-13 16:00:00	2423.6	
2016-07-13 16:30:00	2583.1	
2016-07-13 17:00:00	2816.2	
2016-07-13 17:30:00	3098.1	
2016-07-13 18:00:00	3272.6	1103.5
2016-07-24 14:30:00	1955.5	
2016-07-24 15:00:00	2022.1	
2016-07-24 15:30:00	2117.7	
2016-07-24 16:00:00	2256.8	
2016-07-24 16:30:00	2445.5	
2016-07-24 17:00:00	2681.4	
2016-07-24 17:30:00	2934.9	
2016-07-24 18:00:00	3081.2	
2016-07-24 18:30:00	3086.8	1131.3
2016-07-26 03:30:00	1657.0	
2016-07-26 04:00:00	1683.8	

Trading Interval	SOG (MW)	4 Hour Ramp Rate (MW)
2016-07-26 04:30:00	1725.3	
2016-07-26 05:00:00	1840.3	
2016-07-26 05:30:00	1990.5	
2016-07-26 06:00:00	2239.5	
2016-07-26 06:30:00	2485.3	
2016-07-26 07:00:00	2728.5	
2016-07-26 07:30:00	2816.6	1159.7
2016-08-02 03:30:00	1752.5	
2016-08-02 04:00:00	1770.7	
2016-08-02 04:30:00	1819.0	
2016-08-02 05:00:00	1929.7	
2016-08-02 05:30:00	2062.7	
2016-08-02 06:00:00	2319.3	
2016-08-02 06:30:00	2586.6	
2016-08-02 07:00:00	2833.7	
2016-08-02 07:30:00	2903.2	1150.7

Table 26: 2016 Flexible IRCR Intervals – Proposed Method

Trading Interval	SOG (MW)	4 Hour Ramp Rate (MW)
2017-07-09 14:00:00	1772.1	
2017-07-09 14:30:00	1846.3	
2017-07-09 15:00:00	1941.8	
2017-07-09 15:30:00	2044.2	
2017-07-09 16:00:00	2192.0	
2017-07-09 16:30:00	2350.9	
2017-07-09 17:00:00	2545.7	
2017-07-09 17:30:00	2784.3	
2017-07-09 18:00:00	2865.4	1093.3
2017-08-02 14:30:00	2196.1	
2017-08-02 15:00:00	2233.6	
2017-08-02 15:30:00	2323.4	
2017-08-02 16:00:00	2448.7	
2017-08-02 16:30:00	2611.0	
2017-08-02 17:00:00	2814.7	
2017-08-02 17:30:00	3082.7	
2017-08-02 18:00:00	3288.0	
2017-08-02 18:30:00	3329.4	1133.4
2017-08-03 03:30:00	1892.2	
2017-08-03 04:00:00	1914.0	
2017-08-03 04:30:00	1960.0	
2017-08-03 05:00:00	2069.4	
2017-08-03 05:30:00	2199.9	
2017-08-03 06:00:00	2432.3	
2017-08-03 06:30:00	2645.5	
2017-08-03 07:00:00	2871.4	
2017-08-03 07:30:00	2980.5	1088.4

Trading Interval	SOG (MW)	4 Hour Ramp Rate (MW)
2017-08-10 14:30:00	2094.7	
2017-08-10 15:00:00	2124.2	
2017-08-10 15:30:00	2199.1	
2017-08-10 16:00:00	2309.5	
2017-08-10 16:30:00	2430.2	
2017-08-10 17:00:00	2601.7	
2017-08-10 17:30:00	2858.3	
2017-08-10 18:00:00	3098.7	
2017-08-10 18:30:00	3168.7	1074.0

Table 27: 2017 Flexible IRCR Intervals – Proposed Method

Trading Interval	SOG (MW)	4 Hour Ramp Rate (MW)
2018-07-08 14:00:00	1522.2	
2018-07-08 14:30:00	1574.6	
2018-07-08 15:00:00	1651.9	
2018-07-08 15:30:00	1757.3	
2018-07-08 16:00:00	1901.5	
2018-07-08 16:30:00	2070.3	
2018-07-08 17:00:00	2278.2	
2018-07-08 17:30:00	2525.5	
2018-07-08 18:00:00	2652.6	1130.4
2018-08-11 14:30:00	1675.4	
2018-08-11 15:00:00	1742.7	
2018-08-11 15:30:00	1850.5	
2018-08-11 16:00:00	1984.8	
2018-08-11 16:30:00	2149.7	
2018-08-11 17:00:00	2348.9	
2018-08-11 17:30:00	2609.0	
2018-08-11 18:00:00	2824.5	
2018-08-11 18:30:00	2876.0	1200.6
2018-08-12 14:30:00	1533.6	
2018-08-12 15:00:00	1616.1	
2018-08-12 15:30:00	1721.3	
2018-08-12 16:00:00	1858.4	
2018-08-12 16:30:00	2031.8	
2018-08-12 17:00:00	2236.2	
2018-08-12 17:30:00	2477.7	
2018-08-12 18:00:00	2694.9	
2018-08-12 18:30:00	2768.1	1234.6

Trading Interval	SOG (MW)	4 Hour Ramp Rate (MW)
2018-09-15 14:30:00	1388.0	
2018-09-15 15:00:00	1458.4	
2018-09-15 15:30:00	1550.5	
2018-09-15 16:00:00	1667.7	
2018-09-15 16:30:00	1821.0	
2018-09-15 17:00:00	2008.7	
2018-09-15 17:30:00	2200.9	
2018-09-15 18:00:00	2378.5	
2018-09-15 18:30:00	2513.1	1125.1

Table 28: 2018 Flexible IRCR Intervals – Proposed Method

Trading Interval	SOG (MW)	4 Hour Ramp Rate (MW)
2019-06-18 14:00:00	1936.1	
2019-06-18 14:30:00	1976.2	
2019-06-18 15:00:00	2048.8	
2019-06-18 15:30:00	2163.6	
2019-06-18 16:00:00	2312.6	
2019-06-18 16:30:00	2508.8	
2019-06-18 17:00:00	2739.2	
2019-06-18 17:30:00	3011.6	
2019-06-18 18:00:00	3116.7	1180.6
2019-06-19 14:00:00	1912.5	
2019-06-19 14:30:00	1970.7	
2019-06-19 15:00:00	2040.7	
2019-06-19 15:30:00	2159.2	
2019-06-19 16:00:00	2300.6	
2019-06-19 16:30:00	2515.1	
2019-06-19 17:00:00	2765.1	
2019-06-19 17:30:00	3020.9	
2019-06-19 18:00:00	3124.3	1211.8
2019-07-07 14:00:00	1480.6	
2019-07-07 14:30:00	1560.8	
2019-07-07 15:00:00	1669.0	
2019-07-07 15:30:00	1791.9	
2019-07-07 16:00:00	1948.5	
2019-07-07 16:30:00	2115.4	
2019-07-07 17:00:00	2341.1	
2019-07-07 17:30:00	2576.9	
2019-07-07 18:00:00	2679.5	1198.8
2019-07-14 14:00:00	1419.0	
2019-07-14 14:30:00	1487.8	
2019-07-14 15:00:00	1597.5	

Trading Interval	SOG (MW)	4 Hour Ramp Rate (MW)
2019-07-14 15:30:00	1712.4	
2019-07-14 16:00:00	1878.3	
2019-07-14 16:30:00	2070.3	
2019-07-14 17:00:00	2302.8	
2019-07-14 17:30:00	2556.0	
2019-07-14 18:00:00	2702.2	1283.2

Table 29: 2019 Flexible IRCR Intervals – Proposed Method

Trading Interval	SOG (MW)	4 Hour Ramp Rate (MW)
2020-07-10 14:00:00	1740.7	
2020-07-10 14:30:00	1801.2	
2020-07-10 15:00:00	1908.5	
2020-07-10 15:30:00	2041.2	
2020-07-10 16:00:00	2202.3	
2020-07-10 16:30:00	2426.0	
2020-07-10 17:00:00	2660.7	
2020-07-10 17:30:00	2913.3	
2020-07-10 18:00:00	3040.0	1299.3
2020-07-11 14:00:00	1471.0	
2020-07-11 14:30:00	1535.1	
2020-07-11 15:00:00	1627.6	
2020-07-11 15:30:00	1771.2	
2020-07-11 16:00:00	1967.7	
2020-07-11 16:30:00	2210.7	
2020-07-11 17:00:00	2468.5	
2020-07-11 17:30:00	2705.4	
2020-07-11 18:00:00	2819.9	1348.9
2020-07-12 14:00:00	1351.1	
2020-07-12 14:30:00	1436.6	
2020-07-12 15:00:00	1541.6	
2020-07-12 15:30:00	1680.6	
2020-07-12 16:00:00	1857.4	
2020-07-12 16:30:00	2095.0	
2020-07-12 17:00:00	2335.3	
2020-07-12 17:30:00	2571.1	
2020-07-12 18:00:00	2696.3	1345.2

Trading Interval	SOG (MW)	4 Hour Ramp Rate (MW)
2020-08-30 14:30:00	1207.6	
2020-08-30 15:00:00	1315.0	
2020-08-30 15:30:00	1436.1	
2020-08-30 16:00:00	1631.2	
2020-08-30 16:30:00	1831.1	
2020-08-30 17:00:00	2026.8	
2020-08-30 17:30:00	2232.3	
2020-08-30 18:00:00	2415.2	
2020-08-30 18:30:00	2500.6	1293.0

Table 30: 2020 Flexible IRCR Intervals – Proposed Method

Trading Interval	SOG (MW)	4 Hour Ramp Rate (MW)
2021-06-24 14:00:00	1881.2	
2021-06-24 14:30:00	1950.0	
2021-06-24 15:00:00	2065.2	
2021-06-24 15:30:00	2236.7	
2021-06-24 16:00:00	2426.7	
2021-06-24 16:30:00	2683.1	
2021-06-24 17:00:00	2985.6	
2021-06-24 17:30:00	3268.2	
2021-06-24 18:00:00	3391.4	1510.2
2021-06-26 14:00:00	1473.4	
2021-06-26 14:30:00	1571.0	
2021-06-26 15:00:00	1708.5	
2021-06-26 15:30:00	1875.2	
2021-06-26 16:00:00	2097.1	
2021-06-26 16:30:00	2351.8	
2021-06-26 17:00:00	2626.3	
2021-06-26 17:30:00	2879.7	
2021-06-26 18:00:00	2977.7	1504.4
2021-09-04 14:30:00	1154.9	
2021-09-04 15:00:00	1248.4	
2021-09-04 15:30:00	1416.8	
2021-09-04 16:00:00	1602.9	
2021-09-04 16:30:00	1815.3	
2021-09-04 17:00:00	2081.1	
2021-09-04 17:30:00	2335.9	
2021-09-04 18:00:00	2533.5	
2021-09-04 18:30:00	2649.2	1494.3

Trading Interval	SOG (MW)	4 Hour Ramp Rate (MW)
2021-09-12 14:30:00	1046.4	
2021-09-12 15:00:00	1168.3	
2021-09-12 15:30:00	1329.4	
2021-09-12 16:00:00	1502.9	
2021-09-12 16:30:00	1742.8	
2021-09-12 17:00:00	1990.5	
2021-09-12 17:30:00	2243.8	
2021-09-12 18:00:00	2448.8	
2021-09-12 18:30:00	2571.8	1525.4

Table 31: 2021 Flexible IRCR Intervals – Proposed Method

Trading Interval	SOG (MW)	4 Hour Ramp Rate (MW)
2022-07-03 14:00:00	1288.6	
2022-07-03 14:30:00	1384.9	
2022-07-03 15:00:00	1514.8	
2022-07-03 15:30:00	1712.8	
2022-07-03 16:00:00	1948.2	
2022-07-03 16:30:00	2244.7	
2022-07-03 17:00:00	2525.0	
2022-07-03 17:30:00	2749.7	
2022-07-03 18:00:00	2875.2	1586.6
2022-08-07 14:00:00	1310.7	
2022-08-07 14:30:00	1412.3	
2022-08-07 15:00:00	1582.6	
2022-08-07 15:30:00	1799.6	
2022-08-07 16:00:00	1991.5	
2022-08-07 16:30:00	2225.8	
2022-08-07 17:00:00	2460.3	
2022-08-07 17:30:00	2705.1	
2022-08-07 18:00:00	2850.5	1539.8
2022-08-22 14:30:00	1420.8	
2022-08-22 15:00:00	1539.8	
2022-08-22 15:30:00	1700.8	
2022-08-22 16:00:00	1921.1	
2022-08-22 16:30:00	2178.2	
2022-08-22 17:00:00	2460.1	
2022-08-22 17:30:00	2762.3	
2022-08-22 18:00:00	2986.0	
2022-08-22 18:30:00	3080.6	1659.9

Trading Interval	SOG (MW)	4 Hour Ramp Rate (MW)
2022-08-23 14:30:00	1618.6	
2022-08-23 15:00:00	1742.5	
2022-08-23 15:30:00	1866.1	
2022-08-23 16:00:00	2087.6	
2022-08-23 16:30:00	2319.9	
2022-08-23 17:00:00	2590.5	
2022-08-23 17:30:00	2889.0	
2022-08-23 18:00:00	3103.7	
2022-08-23 18:30:00	3165.5	1546.9

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