Draft Rule Change Report: Method used for the assignment of Certified Reserve Capacity to Intermittent Generators (RC_2019_03)

Standard Rule Change Process

20 April 2021

Contents

1. Rule Change Process and Timeline

On 17 December 2020, the Economic Regulation Authority (**ERA**) submitted a Rule Change Proposal titled 'Method used for the assignment of Certified Reserve Capacity to Intermittent Generators' (RC_2019_03).

Intermittent Generators are assigned Certified Reserve Capacity (**CRC**) based on the Relevant Level Methodology (**RLM**). This Rule Change Proposal seeks to replace the current RLM with a new method that was recommended by the ERA following its 'Review of the method used to assign capacity to intermittent generators 2018' (**RLM Review**).[1]

This proposal is being processed using the Standard Rule Change Process described in section 2.7 of the WEM Rules. The timeframe for the end of the first submission period and for publishing the Draft Rule Change Report were extended by the Rule Change Panel under clause 2.5.10 of the WEM Rules.

The key dates for progressing this Rule Change Proposal, as amended in the extension notices, are:

This Draft Rule Change Report is drafted on the basis that the reader has read all the related documents, including the Rule Change Proposal and the first period submissions. All documents related to this Rule Change Proposal can be found on the Rule Change Panel's website at [Rule Change: RC_2019_03 – Economic Regulation Authority Western Australia](https://www.erawa.com.au/rule-change-panel/rule-changes/rule-change-rc_2019_03).

1 https://www.erawa.com.au/electricity/wholesale-electricity-market/methodology-reviews/review-of-method-used-to-assign-capacity-to-intermittent-generators-2018.

2. The Rule Change Panel's Draft Decision

The Rule Change Panel's draft decision is to accept the Rule Change Proposal in a modified form, as outlined in sections 6.3 and 7 of this report.

2.1 Reason for the Rule Change Panel's Draft Decision

The Rule Change Panel has made its draft decision on the basis that the Amending Rules, as amended following the first submission period:

- will replace the current, inappropriate RLM with a method that:
  - is consistent with the Planning Criterion for the South West interconnected System (**SWIS**);
  - is based on an assessment of the effective load carrying capability (**ELCC**) of the fleet of Intermittent Generators, which is a well-recognised and commonly used approach in other jurisdictions that is generally supported by Market Participants;[2]
  - assesses the capacity value of Intermittent Generators on a fleet basis, which allows the effects of their interactions to be taken into account;
  - reflects the performance of the fleet of Intermittent Generators during Trading Intervals of high system stress, and does not place undue emphasis on Trading Intervals that are less relevant to system reliability;
  - allocates the capacity value of the fleet of Intermittent Generators to individual Facilities (determining the Facilities' Relevant Levels) using a method that is consistent with the method used to determine the fleet's capacity value;
  - does not mute price signals from the Reserve Capacity Mechanism (**RCM**) to locate Intermittent Generators where they will have the greatest benefit for system reliability;
  - ensures that the interactive effects between a Facility and the fleet are credited to Facilities in a manner that captures the effects of their interactions on system reliability;
  - provides for more consistent treatment of new Facilities and existing Facilities;
  - accounts for historical and expected future increases in the level of behind-the-meter photovoltaic (**PV**) generation;
  - is suitable for the increasing levels of Intermittent Generation that are expected in the Wholesale Electricity Market (**WEM**);
  - provides a pragmatic approach to preventing the CRC of committed Facilities from being adversely affected by the determination of Relevant Levels for proposed Facilities and Facilities that are subject to applications for Early CRC or Conditional CRC;

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2 The Rule Change Panel notes that the Facilities or parts of Facilities that are assessed via the RLM are referred to as:

- Intermittent Generators or Candidate Facilities throughout sections 1 to 6 and Appendix A of this report; and
- Candidates in section 7 and Appendix C of this report.

The Rule Change Panel notes that in future the RLM is intended to also apply to some Electricity Storage Resources (**ESR**).

- is transparent and can be used by Market Participants to support their investment planning;

- will be consistent with the Minister's recent reforms to the WEM under the Energy Transformation Strategy (**ETS**), including changes to facility registration and the implementation of the Network Access Quantity (**NAQ**) framework;
- can be implemented by AEMO at a reasonable cost in time for the 2021 Reserve Capacity Cycle;
- will allow the WEM Rules to better achieve Wholesale Market Objectives (a), (b), (c) and (d); and
- are consistent with Wholesale Market Objective (e).

Additional detail outlining the analysis behind the Rule Change Panel's decision is provided in section 6 of this report.

2.2 Proposed Commencement

The Amending Rules are proposed to commence at **8:00 AM** on **6 August 2021**. The commencement date is subject to change in the Final Rule Change Report.

3. Call for Second Round Submissions

The Rule Change Panel invites interested stakeholders to make submissions on this Draft Rule Change Report.

The Rule Change Panel is seeking feedback on all aspects of the Draft Rule Change Report to assist the Rule Change Panel with its assessment of the proposal. However, the Rule Change Panel would like stakeholders to comment in particular on the following aspects of the Draft Rule Change Report:

- What is the latest acceptable time for the publication of CRC and Capacity Credit assignments, and why?
- Is the proposed 10 MW nameplate capacity threshold appropriate for grouping small Facilities for the allocation of the Fleet ELCC, as outlined in section 6.1.8 of this report, and if not, why and what alternative do you suggest?
- Is it appropriate to allow AEMO to include any small Facilities with a nameplate capacity above a selected threshold in the small Facility groups for the purpose of allocating the Fleet ELCC, if AEMO considers that the Facility may otherwise not be assessed appropriately due to rounding issues?
- Do stakeholders have any concerns about the proposed requirement for AEMO to publish the historical output for all Candidate Facilities, including relevant estimates from AEMO and the estimated output from independent expert reports for Trading Intervals before a Facility's full operational date, and if so, what are the concerns?

The submission period is 20 Business Days from the Draft Rule Change Report publication date. Submissions must be delivered to the RCP Secretariat by **5:00 PM** on **Wednesday 19 May 2021**. The Rule Change Panel notes that it does not intend to extend the second submission period because this would increase the risk that this Rule Change Proposal will not be processed in time to be implemented for application in the 2021 Reserve Capacity Cycle.

The Rule Change Panel prefers to receive submissions by email, using the submission form available at: https://www.erawa.com.au/rule-change-panel/make-a-rule-change-submission sent to support@rcpwa.com.au.

Submissions may also be sent to the Rule Change Panel by post, addressed to:

Rule Change Panel
Attn: Executive Officer
C/o Economic Regulation Authority
PO Box 8469
PERTH BC WA 6849

3.1 Further Consultation

The Rule Change Panel plans to convene a Market Advisory Committee (**MAC**) workshop on or near Wednesday 5 May 2021 to review this Draft Rule Change Report and the draft Amending Rules with stakeholders. RCP Support will contact stakeholders in the usual way to schedule this meeting.

The Rule Change Panel is also offering Market Participants the opportunity to meet individually with RCP Support to directly answer questions that Market Participants may have about the Draft Rule Change Report and the draft Amending Rules. These meetings can occur at any time during the second submission period. Market Participants should contact the Executive Officer, Mr Stephen Eliot at support@rcpwa.com.au if they would like to arrange such a meeting.

In addition, the Rule Change Panel intends to publicly release the RLM Model that it used to assess this proposal as an aid for Market Participants to assess the Rule Change Panel's draft decision. However, some of AEMO's data is confidential and some Market Participants may consider the input data to be confidential, so RCP Support has directly contacted AEMO and the relevant Market Participants to seek permission to release the input data, and will release the RLM Model and data if all of the relevant Market Participants agree to release the input data. The Rule Change Panel will advise stakeholders about release of the RLM Model through the RulesWatch newsletter.

4. Proposed Amendments

4.1 The Rule Change Proposal

The ERA seeks to replace the current RLM to reflect the recommendation of the ERA's RLM Review.

4.1.1 Issues with the Current RLM

The ERA considers that the current RLM has several shortcomings due to modelling errors in forecasting capacity values and inconsistency with the Planning Criterion of the SWIS.

In particular the ERA considers that:

- the modelling errors in the current RLM result in excessive errors when forecasting the capacity contribution of Intermittent Generators to reliability in the SWIS;
- the current RLM is not effective in achieving the Wholesale Market Objectives for the following reasons:
  - Wholesale Market Objective (a)[3] – it may lead to over procurement of capacity, which can increase the cost of electricity supply to consumers and lower the economic efficiency of the SWIS;[4]
  - Wholesale Market Objective (b)[5] – it is not transparent; it uses constant parameters in the calculation of the Relevant Level, and the purpose and calculation of these parameters are not defined in the WEM Rules, so Market Participants and new entrants to the SWIS cannot determine the value of these parameters;
  - Wholesale Market Objective (c)[6] – The current RLM can discriminate between facilities and/or technologies. For instance, it does not account for the capacity contribution of new or recently upgraded facilities when calculating the capacity contribution of existing facilities. This approach risks over-estimating or under-estimating the capacity value of existing technologies. Also, the current RLM does not correctly account for the differences in the availability of capacity of Intermittent Generators and how this influences their capacity value. This is particularly important with the uptake of renewable energy technologies in the SWIS.
  - Wholesale Market Objective (d)[7] – it may lead to an over-estimation of the capacity contribution of resources, which may result in under-procuring capacity, which can

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3 Wholesale Market Objective (a) is:

> to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system

4 The Rule Change Panel notes that undervaluing the capacity value of Facilities may lead to AEMO having to procure capacity from additional Facilities to meet the Reserve Capacity Requirement. If AEMO would not have otherwise procured the capacity of the additional Facilities, then this would be an over procurement.

5 Wholesale Market Objective (b) is:

> to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;

6 Wholesale Market Objective (c) is:

> to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

7 Wholesale Market Objective (d) is:

> to minimise the long-term cost of electricity supplied to customers from the South West interconnected system;

result in frequent use of high cost emergency reserves in the system or disconnection of customers, both of which increase the long-term cost of electricity supply to consumers.

- Increased penetration of Intermittent Generators in the system will exacerbate the forecasting inaccuracy of the current RLM.

In its final report of its RLM Review, the ERA stated that the current RLM has several shortcomings and does not provide a reasonable forecast of the capacity contribution of Intermittent Generators to the reliability in the SWIS. The ERA noted that:

- the current RLM does not correctly identify periods with the lowest level of capacity surplus, does not appropriately address the correlation between the capacity of different generators, and makes some other calculation errors;
- the simple formula upon which the current RLM was based can only calculate reasonable capacity values for the fleet of Intermittent Generators when there are very low levels of intermittent generation in the electricity system and this situation no longer applies in the SWIS, where the penetration of Intermittent Generators is increasing; and
- a RLM that does not result in an allocation of Capacity Credits to Intermittent Generators that reflects their contribution to reliability in the SWIS can increase the long-term cost of electricity to consumers and undermine the reliability objective of the WEM.

4.1.2 Overview of the proposed new RLM

This section provides a high-level overview of the ERA's proposed RLM.

4.1.2.1 General Concept

The ERA proposes to base the new RLM on the concept of effective load carrying capability. The ELCC of a Facility (or group of Facilities) represents the amount of load that can be added to a system if this Facility was added to the system, without increasing the system's loss of load expectation (**LOLE**). This means the ELCC is determined as the firm capacity that could replace the assessed Intermittent Generators, without changing the system's LOLE.

The ERA proposes to:

- determine an ELCC for the whole fleet of Intermittent Generators;[8]
- allocate the fleet's ELCC between different groups of Intermittent Generators (based on the Facilities' technology); and
- determine the Relevant Level of the individual Intermittent Generators by allocating the groups' ELCCs between the relevant Facilities based on their relative performance during selected Trading Intervals.

4.1.2.2 Terminology

The Rule Change Panel defines the following terms for the explanation of the ERA's proposed RLM:

- **Candidate Facility** – any Facility (or part of a Facility) for which the CRC for a Reserve Capacity Cycle is assessed using the RLM.

[8] The Rule Change Panel notes that the RLM may be applied to Facilities or parts of Facilities but uses the term Intermittent Generators in this section to increase the readability.

- **Capacity Outage Probability Table (COPT)** – a table that shows, for each whole MW value from 0 MW to the total CRC of the expected facility fleet, excluding Candidate Facilities and Electric Storage Resources (**ESR**), the probability of the SWIS experiencing a total quantity of Forced Outage greater than or equal to that MW value. The proposed COPT is based on the historical Forced Outage rates of all Scheduled Generators and the assumption that Demand Side Programmes (**DSPs**) are always available.
- **Fleet** – the fleet of all Candidate Facilities.
- **LOLE** – Loss of Load Expectation, which is the sum of the LOLPs (based on the COPT) for each Trading Interval in the relevant period.
- **LOLP** – Loss of Load Probability for a given Trading Interval based on:
  - the Scaled Demand;
  - the assumption that ESR reduces the Scaled Demand by the energy reflecting their CRC during Trading Intervals that are Electric Storage Resource Obligation Intervals; and
  - the COPT.
- **Reference Period** – the 7-year period ending at 8:00 AM on 1 April of Year 1 of the Reserve Capacity Cycle for which the RLM is applied.
- **Scaled Demand** – the system demand for each 12-month period of the Reference Period determined by:
  (1) adjusting the observed demand for distributed energy resources (**DER**) uptake; and
  (2) for each 12-month period, scaling the adjusted observed demand for each Trading Interval using a scaling function so that:
    - the maximum of the Scaled Demand values equals AEMO's estimate of the 1-in-10 year peak demand for the Capacity Year for which the RLM is undertaken; and
    - the sum of the Scaled Demand values divided by two (to convert from MW to MWh) for all Trading Intervals in the 12-month period equals AEMO's estimate of expected energy consumption for the Capacity Year for which the RLM is undertaken.
- **Technology Group** – any of the Technology Groups that AEMO must assign the individual Candidate Facilities to, with the relevant Technology Groups being the:
  - Biogas Technology Group;
  - Solar Technology Group; and
  - Wind Technology Group.

4.1.2.3 Determination of the ELCC for a Group of Facilities for a Period

Under the ERA's proposed RLM, an ELCC is determined for any group of Facilities (i.e. any Technology Group or the Fleet) for various periods (i.e. the whole Reference Period or any of the 12-month periods within the Reference Period).[9] The ERA proposes to determine the respective ELCC, as follows:

(1) determine the LOLE for the Scaled Demand;[10]

(2) increase or decrease the Scaled Demand by adding or subtracting demand until the LOLE is equal to or approximate to 8 Trading Intervals in 10 years (the result is the **Amended Scaled Demand**);[11]

(3) reduce the Amended Scaled Demand resulting from step (2) by the generation of the group of Facilities for which the ELCC is calculated (the result is the **Net Demand**);

(4) increase the Net Demand resulting from step (3) in 1 MW increments until the LOLE equals 8 Trading Intervals in 10 years; and

(5) the MW quantity by which the Net Demand was increased under step (4) determines the ELCC of the relevant group of Facilities.

4.1.2.4 ELCC of the Fleet

The ERA proposes to determine the ELCC for the Fleet that is then allocated between the Technology Groups (**Selected ELCC of the Fleet**) for a Reserve Capacity Cycle as the smaller value of:

- the median of the annual ELCCs of the Fleet for each 12-month period in the Reference Period; and
- the ELCC of the Fleet for the whole Reference Period.

4.1.2.5 Facility Group Interaction Effect

Usually the Selected ELCC of the Fleet differs from the sum of the ELCCs for each Technology Group. This difference is defined as the Facility Group Interaction Effect, which can be positive or negative.

The Facility Group Interaction Effect is calculated as the ELCC for the Fleet for the whole Reference Period less the sum of the ELCCs of all Technology Groups for the whole Reference Period.

The ERA proposes to allocate the Facility Group Interaction Effect between the Solar Technology Group and the Wind Technology Group in proportion to the ELCC of each of the Technology Groups for the whole Reference Period.

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9 The Rule Change Panel notes that, in its Final Report and its Rule Change Proposal, the ERA refers to Relevant Level and ELCC interchangeably. However, the Relevant Level is a defined term under the WEM Rules referring to the level assigned to a Facility on which basis the Facility is assigned CRC. In the remainder of this report any reference to the Relevant Level refers to the Relevant Level as defined under the WEM Rules.

10 The Scaled Demand is also adjusted for the contribution of ESR during the Electrical Storage Resource Obligation Intervals.

11 The Scaled Demand is adjusted for this calculation depending on the group of Facilities for which the Relevant Level is calculated (e.g. when determining the ELCC of the Fleet, the scaled Demand is reduced by the generation of all Candidate Facilities and for all groups of Facilities adjustment factors that amend the Scaled Demand).

4.1.2.6 Selected ELCC for each Technology Group

The ELCC that the ERA proposes to apply to each Technology Group to be allocated between the individual Facilities of the group (**Selected ELCC of the Technology Group**) for the relevant Reserve Capacity Cycle is:

- for the Biogas Technology Group, the ELCC of the Technology Group for the whole Reference Period (as per section 4.1.2.3);
- for the Solar Technology Group, the ELCC of the Technology Group for the whole Reference Period (as per section 4.1.2.3) plus its share of the Technology Group's Interaction Effect (as per section 4.1.2.5); and
- for the Wind Technology Group, the ELCC of the Technology Group for the whole Reference Period (as per section 4.1.2.3) plus its share of the Technology Group's Interaction Effect (as per section 4.1.2.5).

4.1.2.7 Relevant Level for Individual Candidate Facilities

The ERA proposes to determine the individual Candidate Facilities' Relevant Levels by allocating the Selected ELCCs of the Technology Groups between the Candidate Facilities in a Technology Group based on the individual Facilities' relative performance compared to the other Candidate Facilities in the Technology Group.

The relative performance for this allocation is based on the Candidate Facilities' average performance during:

- the 84 Trading Intervals that are determined by selecting, for each of the 7 years in the reference period, the 12 Trading Intervals with the highest Scaled Demand that occur on separate Trading Days; and
- the 84 Trading Intervals that are determined by selecting, for each of the 7 years in the reference period, the 12 Trading Intervals with the highest load for scheduled generation (**LSG**) (Scaled Demand minus the total of the output or estimated output of all Candidate Facilities) that occur on separate Trading Days.

4.2 The Rule Change Panel's Initial Assessment of the Proposal

The Rule Change Panel decided to progress this Rule Change Proposal on the basis of its preliminary assessment that the proposal raises a valid issue and may be consistent with the Wholesale Market Objectives.

5. Consultation

5.1 General Consultation

The ERA's Rule Change Proposal is based on the outcome of the RLM Review. As part of this review, the ERA published a draft report that included a draft of the proposed RLM and sought stakeholder feedback on that report. The ERA considered the stakeholder feedback received in preparing its final report for the RLM Review.

5.2 The Market Advisory Committee

5.2.1 MAC Consultation Before the Formal Submission of the Proposal

The ERA discussed its proposed RLM with the MAC prior to submitting its Rule Change Proposal to the Rule Change Panel. These discussions took place at six MAC meetings on 5 February 2019, 30 April 2019, 11 June 2019, 29 July 2019, 20 October 2020 and 17 November 2020.[12] Minutes for these MAC meetings are available on the Rule Change Panel website at https://www.erawa.com.au/rule-change-panel/market-advisory-committee.

The ERA presented the results of its RLM Review at the MAC meeting on 5 February 2019. MAC members and observers raised questions regarding:

- the ERA's proposed approach to allocate the fleet capacity value among individual Facilities using both peak demand and peak LSG rather than just using peak LSG Trading Intervals; and
- the impact of network constraints on the ERA's proposed RLM.

The ERA further discussed the RLM Review at the 30 April 2019 MAC meeting, and consulted with the MAC about its intention to develop a Rule Change Proposal to change the RLM. MAC members and observers raised questions regarding:

- whether the ERA's proposed methodology would adversely affect power system reliability by failing to ensure that sufficient capacity is available to meet a 1-in-10 year peak demand event;
- the implementation costs for the ERA's proposal;
- whether AEMO should use a similar probabilistic model to forecast Intermittent Generator output for PASA reserve margin calculations;
- whether there is a conflict between the ERA's proposed RLM and the rules for early and conditional certification of Reserve Capacity;
- the impact of network constraints on the ERA's proposed RLM; and
- the impact of changes to Scheduled Generators on the ERA's proposed RLM.

The ERA made a further presentation to the MAC on 11 June 2019 to update the MAC on the status of its development of the Rule Change Proposal.

The ERA submitted a Pre-Rule Change Proposal (**PRC**): Method used for the assignment of CRC to Intermittent Generators (RC_2019_03) to the Rule Change Panel for discussion at the 29 July 2019 MAC meeting. The ERA developed the PRC on the basis of its RLM Review and the previous MAC discussions of that review.

12 The ERA also provided an update on its RLM Review at the 13 June 2018 MAC meeting.

After the 29 July 2019 MAC meeting, RCP Support identified that, because the proposed RLM assesses the contribution of individual Intermittent Generators to the system based on the contribution of the Intermittent Generation fleet as a whole, there may be an interaction between the ERA's proposed RLM and the NAQ framework that the Energy Transformation Implementation Unit (**ETIU**) was planning to implement as part of the ETS.[13]

ETIU, the ERA, AEMO and RCP Support discussed this issue in December 2019 and the ERA decided to defer submitting RC_2019_03 while ETIU developed the NAQ framework and the related Amending Rules.

The ERA provided an update on its progress in developing RC_2019_03 at the 20 October 2020 MAC meeting. The ERA noted that:

- it saw no conflict between the proposed RLM and the proposed NAQ framework (based on the draft Amending Rules that ETIU had shared with the ERA) and was undertaking sensitivity analyses to assess the impact of the interaction between the RLM and the NAQ framework; and
- it was amending the PRC to account for:
  - the introduction of ESR; and
  - hybrid Facilities (Facilities comprising different technologies, such as wind and PV).

At the 20 October 2020 MAC meeting, RCP Support and AEMO reiterated several of their previously raised concerns with the PRC, including:

- the potential interaction between the ERA's proposed RLM and ETIU's proposed NAQ framework;
- that the ERA's proposed RLM may not be consistent with the Planning Criterion and may put system reliability at risk; and
- the treatment of ESR and hybrid Facilities.

At the 20 October 2020 MAC meeting, MAC members and observers questioned:

- whether they would be able to test the proposed RLM so that they can better understand the proposal and provide informed feedback;
- whether the proposed RLM would underestimate the ability of Intermittent Generators to contribute to system reliability, in comparison to conventional generators;
- the costs and timing to implement the proposal;
- whether a target level of LOLE should be specified, and if so, how; and
- whether it would be beneficial to require new generators to specify a minimum level of Capacity Credits that they would find acceptable and to automatically withdraw such facilities if the RLM assigned a CRC below this level.[14]

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13 The Amending Rules implementing the NAQ framework (to be first applied to the 2022 Reserve Capacity Cycle) were Gazetted on 24 December 2020 in Schedule C of the *Wholesale Electricity Market Amendment (Tranches 2 and 3 Amendments) Rules 2020* (**T2&3 Amending Rules**). The T2&3 Amending Rules are available at https://www.erawa.com.au/cproot/21670/2/Wholesale-Electricity-Market-Amendment-Tranches-2-and-3-Amendments-Rules-2020.pdf.

14 The Rule Change Panel notes that the Minister inserted clause 4.14.1D in the T2&3 Amending Rules that will require a Market Participant holding CRC for a Facility that is not committed to notify AEMO in writing of the Minimum Capacity Credits Quantity for the Facility for that Reserve Capacity Cycle. However, this notice is not required until after the certification process is complete, so it cannot be used to remove such an uncommitted facility from the RLM process.

The MAC also noted the need to determine whether the interaction between the proposed RLM and the NAQ framework was material and agreed that sensitivity analysis would likely be the best way to assess this issue.

The ERA submitted an updated PRC for discussion at the 17 November 2020 MAC meeting, including the following supporting documents:

- additional scenario analyses prepared by The Lantau Group (this document was later attached to the Rule Change Proposal);
- an informal summary prepared by RCP Support of the concerns it had raised at the 20 October 2020 MAC meeting (this document was later attached to the Rule Change Proposal);
- a document addressing the concerns raised by RCP Support and AEMO, and explaining some changes that the ERA had made to the draft Amending Rules to accommodate implementation of the NAQ framework (this document was later attached to the Rule Change Proposal). These changes included:
  - accounting for ESR;
  - explicitly accounting for hybrid Facilities; and
  - aligning the RLM with the Planning Criterion by scaling each 12-month historical system demand profile used in the RLM so that the peak demand for the 12-month period equals the forecast peak demand with 10% probability of exceedance, as published in the Electricity Statement of Opportunities (**ESOO**) for the future Capacity Year for which the CRC is being determined.

At the 17 November 2020 MAC meeting:

- AEMO and RCP Support raised concerns about the proposed scaling of the historical demand profiles and the proposal to assess different technology components of a hybrid facility separately for the purposes of the RLM.
- The MAC discussed the following key issues:
  - Mr Timothy Edwards (Market Customer representative) noted that, for smaller-sized facilities, the additional cost of an expert report for a 7-year period instead of a five-year period was likely to be around $1,000-$2,000, and was likely to be much the same for a wind/solar hybrid facility regardless of whether the wind and solar components were treated separately or as a combined unit. Mr Edwards did not expect the additional costs would be material for facilities with capacities exceeding 10 MW.
  - Mr Martin Maticka (AEMO representative) questioned the relationship between a 4 hours in 10 years LOLE and the Planning Criterion, and proposed to discuss the issue further with the ERA and RCP Support.
  - Several MAC members considered the Rule Change Proposal should be submitted as soon as possible and that the technical details should be prosecuted during the rule change process.

5.3 Submissions Received During the First Submission Period

The first submission period for this Rule Change Proposal was held between 18 December 2020 and 11 February 2021. The Rule Change Panel received submissions from AEMO, Alinta Energy, Collgar Wind Farm and Synergy. The Rule Change Panel also received a late submission on 18 February 2021 from the Australian Energy Council (**AEC**).

Although the Rule Change Panel has summarised the submissions in accordance with clause 2.7.7 of the WEM Rules, the Rule Change Panel has reviewed the submissions in their entirety and considered each matter raised by the Rule Participants in making its draft decision on this Rule Change Proposal.

5.3.1 General Feedback

AEMO raised concerns with the Rule Change Proposal. Alinta Energy, AEC and Synergy supported the Rule Change Proposal; and Alinta Energy and Synergy suggested some amendments to the proposed RLM. The issues raised and suggestions made in the submissions are discussed in the remainder of this section and in Appendix A of this report.

Collgar Wind Farm noted that it could not assess the impact of the Rule Change Proposal with the information available and was therefore not in a position to support the proposal. Collgar Wind Farm requested the release of the ERA's model and input data to Market Participants.

5.3.2 Consistency of the Proposed RLM with the Planning Criterion

AEMO raised concerns that the proposed RLM is not aligned with the Planning Criterion. AEMO considered that the proposed RLM may overvalue the capacity values of wind farms and may compromise system reliability.

AEMO raised concerns that the use of 7 years of historical data may overestimate the contribution of wind farms during the conditions of a 1-in-10 year peak demand event. AEMO considered that such an event would be primarily driven by high air temperature in the Perth metropolitan area. AEMO provided analysis of the average performance of wind farms at each degree of incremental air temperature above 38°C, measured at Perth Airport, based on historical data. AEMO considered that its analysis suggests that:

- wind farms located in the northern and eastern regions of the SWIS show a decrease in their average performance level as air temperature increases from 38 degrees Celsius to 44 degrees Celsius (measured at Perth Airport).
- wind farms located in the southern region of the SWIS do not show a consistent trend of reduction in their average performance level at temperatures greater than 38 degrees Celsius (measured at Perth Airport).

AEMO noted that the SWIS has seldom experienced a 1-in-10 year peak demand event. Therefore, historical wind farm output data may not sufficiently capture the potentially reduced available capacity of the wind farms during such an event.

AEMO raised concerns that the proposed scaling of the historical demand in each 12-month period of the 7-year reference period to the expected 1-in-10 year peak demand may overestimate the wind farms' capacity values. AEMO considered that the 1-in-10 year peak demand would be mainly driven by high air temperature. However, the proposed RLM does not adjust the historical output of wind farms to reflect the different weather conditions that would have led to the scaled demand and therefore may overestimate their contribution.

Alinta Energy indicated that it does not support any proposal to scale Intermittent Generators' output to reflect available capacity during 1-in-10 year peak demand intervals because this would require the RLM to incorporate highly fraught and arbitrary forecasts.[15]

AEMO recognised that any adjustment to the historical output of wind farms is complex and requires an investigation of all wind farms' performance-related parameters and limitations. AEMO considered that any adjustment must ensure that the adjusted output of the wind farms is statistically correlated with system demand and the output of other Intermittent Generators in the system. AEMO suggested that this could be considered as part of the next RLM review during which available meteorological models and power de-rating features could be investigated to explain the possible effect of the available capacity of wind farms during very high air temperature periods.

5.3.3 Determining the Fleet ELCC

The ERA proposes to determine the Selected ELCC for the Fleet for a Reserve Capacity Cycle as the smaller value of:

- the median of the ELCCs of the Fleet in each 12-month period in the Reference Period (**Median ELCC**); and
- the ELCC of the Fleet in the whole Reference Period (**Whole Period ELCC**).

AEMO raised concerns about using the Median ELCC to determine the Selected ELCC of the Fleet. AEMO considered that using the Median ELCC indicates that the capacity provided by the Fleet to meet the 1-in-10 year peak demand event is expected to be at least equal to the Fleet's Selected ELCC with a 50% probability. AEMO considered that this may not provide adequate certainty of the estimated Fleet's capacity value compared to the expected available capacity of Scheduled Facilities and DSP for the purpose of assigning CRC.

AEMO noted that clause 4.11.1(h) of the WEM Rules allows AEMO to decide not to assign any CRC or to assign a lesser quantity of CRC to a Scheduled Facility if its historical Forced Outage rate is greater than the Outage rate limit of 10%, as outlined in clause 4.11.1D. AEMO considered that this indicates that the capacity provided by a Scheduled Facility is expected to be at least equal to the Facility's CRC with a probability of 90%.

AEMO noted that the Relevant Demand of a DSP (which determines the maximum CRC AEMO may assign to a DSP) is capped at the tenth lowest value of the 200 metered consumption values of the DSP's Associated Loads identified for the 200 Calendar Hours with the highest Total Sent Out Generation. AEMO considered that this indicates that the capacity provided by a DSP is expected to be at least equal to the DSP's CRC with a probability of 95% over the period of 200 hours.

AEMO suggested that a practical approach to amending the Proposed RLM would be to use the average of the sixth and seventh lowest of the yearly Fleet ELCCs, rather than the Median ELCC to determine the Selected ELCC for the Fleet. This average ELCC is approximately at the tenth percentile of the 7 yearly Fleet ELCCs. AEMO considered the use of the average of the sixth and seventh lowest yearly Fleet ELCCs could improve certainty of

[15] Alinta indicated that AEMO and RCP Support proposed to scale Intermittent Generators' output to reflect available capacity during 1-in-10 year peak demand intervals. However, the Rule Change Panel notes that this is incorrect – the ERA has not proposed to scale Intermittent Generators' output to reflect available capacity during a 1-in-10 year event; and AEMO and RCP Support also did not make such a proposal, they only indicated that Intermittent Generators' output would need to be scaled if the demand was scaled in the manner proposed by the ERA.

the Fleet's expected capacity value during a 1-in-10 year peak demand event and may mitigate the risk of overestimating the capacity value of the Fleet due to the lack of performance data. AEMO considered that this would ensure that sufficient capacity will be available from the Fleet contributing towards meeting the Planning Criterion and thus avoiding significant costs to consumers due to loss of load events in the SWIS.

Alinta Energy and Synergy did not support the use of the lower of the Median ELCC and the Whole Period ELCC because of the approach's potential to underestimate the Fleet's capacity value.

Alinta Energy noted that part of the ERA's rationale for using the minimum of the Whole Period ELCC and the Median ELCC was that the Median ELCC alone may be susceptible to extremely large or small values due to the 'small' sample size of five years. Alinta Energy considered that:

- the Whole Period ELCC would be equally influenced by large and small values, and therefore adopting the Whole Period ELCC where it is lower than the Median ELCC risks extremely low values, skewing the results and underestimating the Fleet's capacity value;
- increasing the sample size from 5 to 7 years, as proposed under Step 1(b) would make the Median ELCC more resilient to outliers; and
- taking the minimum of the Median ELCC and Whole Period ELCC is inconsistent with several other jurisdictions.

Synergy also considered that the increase of the sample size from 5 to 7 years will make the Median ELCC more resilient to outliers.

Alinta Energy and Synergy recommended determining the Selected ELCC of the Fleet as the Median ELCC without considering the Whole Period ELCC.

5.3.4 Setting of the Target LOLE

Alinta Energy supported the proposal to estimate the Selected ELCC of the Fleet based on a target LOLE that aligns with the reliability standards in the WEM. However, Alinta Energy disagreed that the 4-hour Electric Storage Resource Obligation Duration (**ESROD**) indicates that the LOLE target for the WEM is 4 hours in 10 years. Alinta Energy considered that 4 hours had been selected as the ESROD because of the limited storage duration of ESRs. Alinta Energy also noted that other jurisdictions have much higher target LOLEs.

Alinta Energy considered that the 14-hour period of 'Peak Trading Intervals' used to determine the fuel requirement for Scheduled Generators is a more appropriate indicator of the WEM's LOLE target. Alinta Energy suggested that, unlike the 4-hour ESROD, the 14-hour fuel requirement was selected to maintain reliability by obliging generators to have enough fuel to remain available for the Peak Trading Intervals; and that it better aligns with the LOLE targets and reserve margins used in the other jurisdictions that it examined.

Synergy suggested that the appropriateness of the 4 hours in 10 year target LOLE should be reassessed at the next RLM review.

5.3.5 Treatment of Proposed Facilities

Synergy raised concerns about the approach to include proposed Facilities in the group of Candidate Facilities that make up the Fleet.

Synergy considered that including proposed Facilities in the Fleet increases the uncertainty of Capacity Credit allocation for committed Facilities and that it inequitably penalises committed and existing Facilities by allocating a lower CRC due to proposed Facilities that are not required to meet the Reserve Capacity Requirement because:

- proposed Facilities only receive Capacity Credits if the Reserve Capacity Target is not met with committed Facilities and can also withdraw their participation in the RCM before the assignment of Capacity Credits; and
- the withdrawal of Facilities from the certification process negatively impacts existing and committed Facilities by reducing the Capacity Credits assigned to them and affecting the NAQ allocation.

Synergy suggested to only run the RLM for existing and committed Facilities that have applied for Capacity Credits.

AEMO noted that the Rule Change Proposal attempts to apply the proposed RLM to assess Conditional Certified Reserve Capacity and Early Certified Reserve Capacity (**Early CRC**), but expressed concern that the proposed changes are not sufficiently clear to allow implementation.

5.3.6 Allocating the Fleet ELCC to Technology Groups

Alinta Energy raised concerns that determining the Selected ELCC for each Technology Group introduces complexity and potential issues. Alinta Energy considered that:

- the use of Technology Groups will increase the volatility of RLM results and increase the sensitivity of the RLM to withdrawals of Facilities from the RCM;
- the ERA's proposed calculation of the Interaction Effect may be incorrect because the Fleet ELCC may be based on a different reference period than the ELCCs of the different Technology Groups;
- the ERA's proposed allocation of the Interaction Effect to wind and solar Facilities may be incorrect because there may be other reasons for the difference between the Fleet capacity value and the sum of the Technology Group capacity values, such as:
    - correlations between Facilities other than wind and solar Facilities; and
    - the differences between how the capacity values are proposed to be calculated for the Fleet versus for the Technology Groups; and
- incorporating Facility Groups increases the complexity and reduces the transparency of the RLM.

Alinta Energy noted that this step was added after the ERA published its draft report for the RLM Review and recommended that the Rule Change Panel consider whether this step is necessary.

5.3.7 Timeframe for CRC Assessment

AEMO noted that the proposed RLM uses the CRC for Scheduled Facilities and DSPs as inputs. AEMO considered that this means that the RLM must be undertaken after the CRC assessment and assignment of CRC to all Scheduled Facilities and DSPs. Therefore, the processes which could previously be performed concurrently must now occur sequentially.

AEMO considered that the proposed RLM requires significantly more inputs and calculation components than the current RLM. As such, AEMO considered that it will require additional time to process the inputs, carry out the RLM calculation, and resolve any calculation issues that may arise while addressing any calculation queries that Market Participants may have as part of the process. AEMO estimated that the proposed RLM would add a minimum of 7 to 9 Business Days to the time required for AEMO to prepare the calculation inputs and complete the RLM calculation.

AEMO suggested amending the date in clause 4.1.11 of the WEM Rules by which AEMO must cease to accept lodgement of applications for CRC to a date that is at least 7 to 9 Business Days earlier than the current date. AEMO provided reasons for this suggestion in its submission.

5.3.8 Transparency of the RLM

Alinta Energy indicated that the proposed RLM will improve transparency because it will:

- remove use of the ill-defined K and U parameters in the current RLM;
- allow Market Participants and prospective investors to more easily predict the capacity values of their Facilities; and
- be more resilient to changes in the SWIS.

Synergy indicated that the method used to determine Scaled Demand under Appendix 9, Part B, Step 7, is unclear and suggested that transparency could be improved by specifying in a WEM Procedure the method by which AEMO estimates the behind-the-meter PV generation.

5.3.9 Transitional Arrangements

Synergy suggested that it was unclear whether the Rule Change Proposal was still contemplating transitional arrangements and indicated that it would not support the transitional arrangements that had been previously discussed.[16]

5.3.10 Submitters' Assessment of the Proposal against the Wholesale Market Objectives

The assessment by submitting parties as to whether the proposal would better achieve the Wholesale Market Objectives is provided in Table 1.

Table 1: Submitters' assessment against the Wholesale Market Objectives

Submitter	Wholesale Market Objective Assessment
AEMO	AEMO is concerned that the proposed RLM may overvalue the capacity contribution of the fleet of Intermittent Generators to the system reliability of the SWIS. This may: • Reduce the effectiveness of the Reserve Capacity Mechanism in ensuring the reliable supply of electricity in the SWIS. • Provide diminishing investment signals for entry of dispatchable capacity that would support the system reliability of the SWIS. Therefore, this may result in an inefficient entry of new capacity into the WEM.

16 The Rule Change Panel notes that the ERA did not include the transitional arrangements discussed at the MAC in the Rule Change Proposal.

Submitter	Wholesale Market Objective Assessment
	• Create discrimination in the market against the contribution of dispatchable capacity to system reliability. • Increase the risk of a capacity shortfall and occurrence of unserved energy, resulting in potential substantial costs to consumers. AEMO considers that the Amending Rules created under the Rule Change Proposal will not facilitate the achievement of the Wholesale Market Objectives (a), (b), (c), and (d).
AEC	The AEC supported the Rule Change Proposal but did not provide a specific assessment of the proposal against the Wholesale Market Objectives.
Alinta Energy	**Wholesale Market Objective (a)** Alinta Energy considers the proposed RLM will more accurately forecast the capacity value of Intermittent Generators in the SWIS. This will improve efficiency by: • avoiding under or over-procurement of capacity; and • ensuring that investors are not incorrectly disincentivised from investing in wind facilities. The Whole of System Plan predicts that investment in wind capacity is required for the SWIS to achieve least cost outcomes over the next 20 years.[17] This will also improve reliability by sending investors more precise signals about what capacity is required to ensure there is enough supply to meet demand in the SWIS. Alinta Energy indicated that its proposal to apply a LOLE target of 14 hours in 10 years will help the Rule Change Proposal better achieve this objective because a Facility's Relevant Level and the price signal ultimately sent to investors will be more consistent with the reliability standards in the WEM. By comparison, the 4-hour LOLE target is more likely to understate the level of capacity in the SWIS, and overstate the need for investment, which could lead to over-procurement. **Wholesale Market Objective (b)** Alinta Energy considers that the proposed method will improve competition among generators in the SWIS by removing the barrier to entry that the current method presents. ERA's analysis shows that the current method may overvalue existing generators and undervalue new generators because it assesses Facilities individually, without properly accounting the contribution of other Facilities. By assessing the capacity value of the fleet of Intermittent Generators simultaneously, the proposed RLM corrects this issue and levels the playing field for new generators, improving competition.

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Submitter	Wholesale Market Objective Assessment
	The proposed RLM will also encourage competition by allowing prospective investors to forecast the capacity revenue of potential investments more easily. **Wholesale Market Objective (c)** The ERA's analysis shows that the current method does not correctly identify the intervals where capacity is the most valuable to the system's reliability, and does not properly account the contribution of new Facilities when assessing the value of existing Facilities. The proposed method aims to correct these errors and thereby remove the resultant discrimination against certain technologies. The proposed method will avoid discrimination against intermittent generation technologies relative to Scheduled Generators by assessing the fleet's capacity value more accurately. Alinta Energy considers that its proposals to: • apply a LOLE target of 14 hours; and • determine the RL_Fleet as the median of the Annual_RL_Fleet values. will further improve the accuracy of the RLM. This would enhance the Rule Change Proposal's achievement of this objective. **Wholesale Market Objective (d)** By more accurately valuing wind and solar capacity, the proposed method avoids the risk that current method incorrectly disincentivises investment in these technologies, which are expected to be the most cost-effective sources of generation over the next two decades.[18] Alinta Energy considers that its proposals to: • apply a LOLE target of 14 hours; and • determine the RL_Fleet as the median of the Annual_RL_Fleet values. will further improve the accuracy of the RLM. This would enhance the Rule Change Proposal's achievement of this objective.
Collgar Wind Farm	Collgar Wind Farm indicated that it is not in a position to provide comment without evaluating ERA's proposed RLM.
Synergy	Synergy considers the Rule Change Proposal will better facilitate the achievement of the Wholesale Market Objectives (a), (b), (c) and (d) as follows: • **Economic efficiency**: The Rule Change Proposal promotes the economically efficient safe and reliable production and supply of electricity in the SWIS by more accurately accrediting Intermittent Generators based on their contribution to system adequacy. • **Encourage competition**: Correction of prevailing issues is likely to minimise the current distortion of investment signals and ensure

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Submitter	Wholesale Market Objective Assessment
	correct allocation of future NAQs, hence facilitating the entry of new competitors. • **Avoid discrimination**: The Rule Change Proposal does not present barriers to new technologies and, by being technology neutral, facilitates the avoidance of discrimination. • **Minimise the long-term cost of electricity**: The proposed changes seek to rectify inaccuracies in the RLM that may lead to over or under allocation of Capacity Credits to Intermittent Generators, thereby minimising costs in the long-term.

5.4 The Rule Change Panel's Response to Submissions Received During the First Submission Period

The Rule Change Panel's response to each of the specific issues raised in the first submission period is presented in Appendix A of this report. A more general discussion of the analysis undertaken by the Rule Change Panel on this Rule Change Proposal, which addresses the main issues raised in submissions and the Rule Change Panel's response to these issues, is available in sections 6.1 and 6.2 of this report.

5.5 Consultation after the First Submission Period

Between the close of the first submission period and the publication of this report, the Rule Change Panel has consulted closely with:

- AEMO to:
  - identify any issues relating to the implementation and operation of the proposed changes as early as possible; and
  - draw on AEMO's expertise about the RCM and system security.
- Energy Policy WA (**EPWA**) to ensure the proposed RLM is not in conflict with any of the Government's reforms.

5.6 Public Forums and Workshops

The Rule Change Panel did not hold a public forum or workshop for this Rule Change Proposal.

6. The Rule Change Panel's Draft Assessment

In preparing its Draft Rule Change Report, the Rule Change Panel must assess the Rule Change Proposal in light of clauses 2.4.2 and 2.4.3 of the WEM Rules.

Clause 2.4.2 of the WEM Rules states that the Rule Change Panel '*must not make Amending Rules unless it is satisfied that the WEM Rules, as proposed to be amended or replaced, are consistent with the Wholesale Market Objectives*'. Additionally, clause 2.4.3 of the WEM Rules states that, when deciding whether to make Amending Rules, the Rule Change Panel must have regard to:

- any applicable statement of policy principles the Minister has issued to the Rule Change Panel under clause 2.5.2 of the Rules;
- the practicality and cost of implementing the proposal;
- the views expressed in submissions and by the MAC; and
- any technical studies that the Rule Change Panel considers necessary to assist in assessing the Rule Change Proposal.

When making its draft decision, the Rule Change Panel has had regard to each of the matters identified in clauses 2.4.2 and 2.4.3 of the WEM Rules, as follows:

- the Rule Change Panel's assessment of the Rule Change Proposal against the Wholesale Market Objectives is available in section 6.4 of this report;
- the Rule Change Panel notes that there has not been any applicable statement of policy principles from the Minister in respect of this Rule Change Proposal;
- the Rule Change Panel's assessment of the practicality and cost of implementing the Rule Change Proposal is available in section 6.6 of this report;
- a summary of the views expressed in submissions and by the MAC is available in section 5 of this report. The Rule Change Panel's response to these views is available in section 5.4 and Appendix A of this report; and
- the Rule Change Panel does not believe a technical study in respect of this Rule Change Proposal is required and therefore has not commissioned one.

The Rule Change Panel's assessment is presented in the following sections.

6.1 Assessment of the Proposed Changes

6.1.1 Inappropriateness of the current RLM

The ERA considers that the current RLM is inappropriate and needs to be replaced. On page 6 of its Rule Change Proposal, the ERA states that:

> 'The ERA found that the current method had several shortcomings due to modelling errors in forecasting capacity values and inconsistency with the planning criterion of the SWIS. Modelling errors in the current relevant level method result in excessive errors when forecasting the capacity contribution of intermittent generators to reliability in the SWIS. The current method is not effective in achieving market objectives, as explained in section 4. Increased penetration of intermittent generators in the system will exacerbate the forecasting inaccuracy of the current RLM.

> Under the market rules, the ERA is also responsible for determining the value of two constant parameters that are used in the current RLM (parameters K and U). The ERA found that the application of these constant parameters was not conceptually correct and therefore finding values for these parameters was not possible. A detailed explanation of the shortcomings of the current method was presented in the ERA's Final Report.'

The Rule Change Panel has considered the ERA's Final Report on the RLM Review and for the reasons provided by the ERA agrees that the current RLM is inappropriate for measuring the contribution of Intermittent Generators to system reliability in the SWIS and should be replaced.

6.1.2 Interpretation of the Planning Criterion and the Reserve Margin

The Rule Change Panel notes that, during the pre-rule change process, there was disagreement between the ERA and RCP Support about the interpretation of the Planning Criterion.

As outlined on page 8 of Appendix 3 of the ERA's Rule Change Proposal, the ERA indicates that it understands the Planning Criterion to require there to be sufficient actual available capacity, and not CRC, to meet the specified level of forecast peak demand. The ERA argues that:

> 'Available capacity of any resource, including Intermittent Generators, at the time of one-in-10 year forecast peak demand is uncertain and can be smaller or larger than the CRC. Therefore, the CRC is not equal to available capacity, or necessarily expected available capacity, during a forecast one-in-10 year peak demand period.'

However, RCP Support understands that the Planning Criterion sets out how AEMO must determine the Reserve Capacity Requirement in accordance with clause 4.5.10(b) of the WEM Rules, and that the Reserve Capacity Requirement sets the minimum number of Capacity Credits that AEMO must procure. As such, RCP Support is of the view that the Planning Criterion (as set out in clause 4.5.9 of the WEM Rules) and clause 4.5.10(b) of the WEM Rules, when read in conjunction, require the aggregate amount of Capacity Credits to be sufficient to meet a 1-in-10 year forecast peak demand plus a reserve margin. This reserve margin is defined as the greater of 7.6% of peak demand (including transmission losses and allowing for Intermittent Loads) and the maximum capacity of the largest generating unit at 41degrees Celsius.

The Rule Change Panel has sought expert advice on this matter from the consultant that undertook the last review of the Planning Criterion (Market Reform), who supported RCP Support's interpretation of the Planning Criterion.

Therefore, the Rule Change Panel agrees with RCP Support's understanding of the Planning Criterion and has based its assessment in the remainder of this report on that understanding.

6.1.3 RLM Model and Data Input

To assess the Rule Change Proposal, the Rule Change Panel engaged The Lantau Group to build a model that reflects the proposed RLM and use the model to run several sensitivity analyses.

The model is based on the model that the ERA developed for its RLM Review, which The Lantau Group later amended on behalf of the ERA during the pre-rule change process. The ERA agreed to release the model to the Rule Change Panel for the assessment of the Rule Change Proposal.

For the Rule Change Panel's analysis, The Lantau Group amended the model to reflect the RLM proposed in the Rule Change Proposal (as outlined in section 4.1.2 of this report) except for the following aspects:

- the model does not include the scaling function that scales the historical demand of each year in the 7-year Reference Period so that:
  - the peak demand equals the estimated 1-in-10 year peak demand;
  - the total consumption equals the expected annual consumption; and
- modifications to the determination of the Forced Outage Rates for the COPT from what was proposed by the ERA, as outlined in section 6.1.9 of this report.

This model is referred to as the Base Model in the remainder of this report.

The scaling function has not been included in the Base Model because the Rule Change Panel considered that it is impossible for the Rule Change Panel and The Lantau Group to anticipate and apply the scaling function that AEMO would develop if the scaling function requirement was adopted.

The Lantau Group has also amended various aspects of the Base Model to assess the various aspects of the Rule Change Panel's draft decision, as explained throughout this section 6.1.

The input data used for the modelling of the different scenarios was provided by AEMO.

AEMO has identified issues with the Relevant Level values it calculated for the 2016 and subsequent Reserve Capacity Cycles (i.e. for the 2018/19 to 2022/23 Capacity Years) and is currently investigating the matter. AEMO has provided revised facility sent-out values to the Rule Change Panel for its modelling of Rule Change Proposal RC_2019_03. AEMO's preliminary analysis suggests that the overall financial impact of these issues on the WEM is minimal, ranging from -0.03% ($100,000) to 0.05% ($300,000) of the total Capacity Credit payments for each affected Capacity Year. AEMO has indicated that this issue does not impact the principles of Rule Change Proposal RC_2019_03, and that it will advise the affected Market Participants as soon as it has completed its end to end assessment of this matter.

The Candidate Facilities used for the model calculations comprise only Candidate Facilities for which a complete data set was available for a consistent configuration for the 7-year Reference Period (8:00 AM on 1 April 2013 to 8:00 AM on 1 April 2020). The performance data for the individual Candidate Facilities is based on:

- independent expert reports provided to AEMO for Trading Intervals before the full operational date of the Facility or its latest relevant upgrade; and
- the actual metered generation (substituted by AEMO's estimate where the Facility's output was reduced in a Trading Interval and AEMO is required to use an estimate) for Trading Intervals from the full operational date.

6.1.4 General Concept of the ERA's Proposed RLM

The ERA proposes to determine the Relevant Level for the individual Candidate Facilities by determining the ELCC of the Fleet of Candidate Facilities and then allocating this value between the individual Candidate Facilities based on the ELCC of different Technology Groups and the relative performance of the individual Candidate Facilities during specified Trading Intervals of high system stress.

This section 6.1.4 outlines the Rule Change Panel's assessment of the proposal to:

- determine a capacity value that is then allocated to the Candidate Facilities; and
- determine the capacity value of the Fleet based on the ELCC.

Assessing the Intermittent Generators as a Fleet

The Rule Change Panel agrees with the ERA's proposal to determine a capacity value for the Fleet that is to be allocated between the Candidate Facilities because:

- the benefit to system security from a fleet of Intermittent Generators with complementary characteristics can be greater than the sum of the benefits of the individual Intermittent Generators; and
- Intermittent Generators with similar operating characteristics can provide diminishing returns in terms of system reliability (e.g. where two Intermittent Generators using the same technology are placed in the same location, the first Intermittent Generator may provide a higher benefit to system reliability than the second).

No concerns were raised with the ERA's proposed approach by the MAC or in submissions.

Using ELCC measures to determine the Relevant Level

In its Final Report for the RLM Review, the ERA outlined the reasons for its decision to propose using a measure of ELCC to determine Relevant Levels. Among other reasons, the ERA considered that only a method based on numerical modelling (such as the proposed method) is likely to provide capacity values that best reflect the capacity contribution of Intermittent Generators to the reliability of the system.

As outlined in the ERA's Rule Change Proposal, the ELCC is widely used in other jurisdictions.

The Rule Change Panel notes that, contrary to common practice, the Planning Criterion for the SWIS does not specify a target LOLE. As outlined in section 6.1.2 of this report, the Rule Change Panel considers that the Planning Criterion and the assignment of CRC to Scheduled Generators based on their generation capability at 41 degrees Celsius indicates that CRC is assigned based on the capacity expected to be available during high demand events in the SWIS, which usually happen on days with high air temperatures.

Therefore, for the ELCC to be an appropriate method to determine the Relevant Levels in the SWIS, the ELCC for a period must adequately reflect the contribution of Intermittent Generators to system reliability during the Trading Intervals with the highest demand in that period.

The Rule Change Panel considers that it is only appropriate to use the ELCC to determine the Relevant Levels if the ELCC of a period is not substantially higher than the ELCC of the Trading Intervals with the highest system stress in that period.

Therefore, the Rule Change Panel decided to assess the appropriateness of using the ELCC for the RLM by comparing the Fleet ELCC for the whole Reference Period with the Fleet ELCCs of different subsets of Trading Intervals with high system stress in the whole Reference Period. However, applying a 4 hours in 10 years LOLE target, as proposed by the ERA, to reference periods of different lengths will result in different targets for each reference period (i.e. 5.6 Trading Intervals for the 7 year period and 0.01 Trading Intervals for the period containing the 200 Trading Intervals with the highest system demand). Therefore, to assess whether the ELCC adequately reflects the contribution of Intermittent Generators to system reliability during Trading Intervals with the highest demand in that period, the Rule Change Panel adjusted the Base Model to remove the 4 hours in 10 years LOLE target and therefore the initial scaling of the system demand to reach this target.

The Rule Change Panel calculated the following ELCCs for the Fleet using this adjusted Base Model:

- ELCC for the 7-year Reference Period;
- ELCC for the 200 Trading Intervals with the highest system demand in the 7-year Reference Period;
- ELCC for the 100 Trading Intervals with the highest system demand in the 7-year Reference Period;
- ELCC for the 50 Trading Intervals with the highest system demand in the 7-year Reference Period; and
- ELCC for the 25 Trading Intervals with the highest system demand in the 7-year Reference Period.

The results of these calculations are illustrated in figure 1.

Figure 1: Comparison of Fleet ELCC for the 7-year Reference Period and for the Trading Intervals with the highest system demand without setting an initial target LOLE

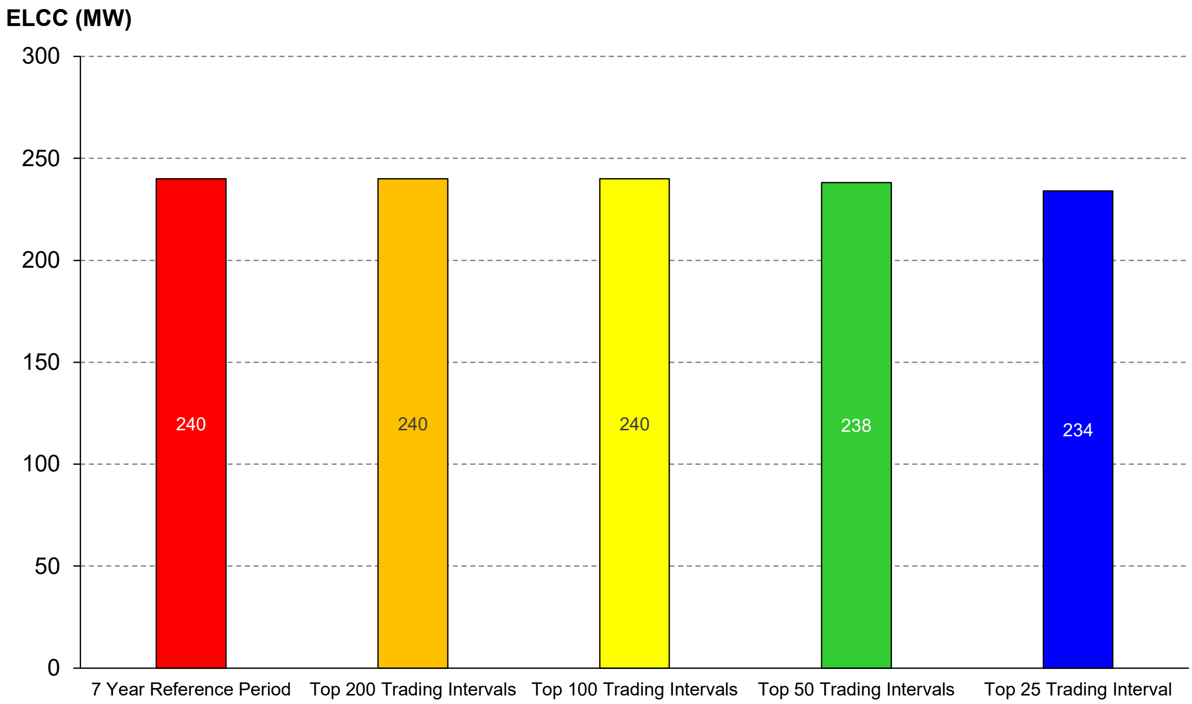

Figure 1 indicates that the ELCC of the 7-year Reference Period is driven by the Trading Intervals with the highest system stress (i.e. the highest system demand). The Rule Change Panel considers that this indicates that it is possible to use an ELCC measure to determine the Fleet's contribution to system reliability that is consistent with the Planning Criterion. However, the Rule Change Panel notes that this will rely heavily on choosing an appropriate target for system reliability, as outlined in section 6.1.6 of this report.

No concerns have been raised by the MAC or in submissions received in the first submission period about the use of ELCC in general. Market Participants have generally been supportive of the use of an ELCC-based method. In their second period submission, Alinta Energy and Synergy supported the use of an ELCC-based method.

The Rule Change Panel's draft decision is to adopt the use of ELCC to determine the capacity value of the Fleet, but to amend the ERA's proposal as outlined in the remainder of this section 6.1.

6.1.5 Choice of Input Data for System Demand and Performance of Candidate Facilities

The ERA proposes to determine the ELCC for the Fleet based on historical system demand and historical performance of the Candidate Facilities, and relying on expert reports for Trading Intervals before the full operation date of any Facility.

The ERA proposes to use the system demand[19] of the 7-year period ending on 1 April of Year 1 of the relevant Reserve Capacity Cycle for the RLM, adjusted by a scaling function that:

- accounts for the expected generation from DER, including behind-the meter PV generation; and
- scales the historical system demand to achieve the following:
    - the peak demand in each 12-month period of the Reference Period equals the estimated 1-in-10 year peak demand for the relevant Capacity Year; and
    - the total consumption in each 12-month period of the Reference Period equals the expected annual consumption for the relevant Capacity Year.

This section 6.1.5 outlines the Rule Change Panel's assessment of the proposal to:

- use historical data as the basis for the RLM;
- extend the current reference period for the RLM from five to 7 years;
- adjust the historical demand for the uptake in DER capacity; and
- scale the historical demand for each 12-month period so that the peak demand equals the 1-in-10 year peak demand forecast, and the total consumption is equal to the expected annual consumption.

Using Historical Data

The ERA proposes to use historical data for system demand and the performance of Intermittent Generators as the basis for determining the Relevant Levels. On page 22 of its Final Report for the RLM Review, the ERA acknowledges the following problems with the use of historical data for the assessment of the Candidate Facilities:

> 'As required by the planning criterion of the Market Rules, AEMO procures sufficient capacity to ensure the system can cover a 1-in-10 year forecast demand. However, observed demand in the SWIS has never been very close to one in 10-year peak demand forecast and extremely high demand periods have occurred very rarely. It is not

19 The proposal is to define system demand as metered sent-out generation plus DSP dispatch plus Interruptible Load dispatch plus load shedding. The Rule Change Panel notes that the ERA refers to this demand in its Rule Change Proposal as Observed Demand.

clear how intermittent generators would contribute to the supply of electricity when demand is as high as one in 10-year peak demand forecast.

Historical time-series data may not provide sufficient information about the output of intermittent resources when the loss of load is the greatest. This lack of relevant data can influence the accuracy of capacity value forecasting. This is particularly important because there is evidence that some intermittent resources have reduced output during extremely hot days when system demand is extremely high.

Assessing the forecasting accuracy of a method is also challenging. The forecasting accuracy of a capacity valuation method cannot be assessed unless the outcomes of the method are repeatedly compared to the actual contribution of intermittent generators. The comparison of the outcomes of the forecast method with the actual contribution of resources in a single year or for a few years cannot provide a reasonable indication of the accuracy of the method. The gap between model outcomes and actual data can simply be due to the variable nature of intermittent generation and its dependence on weather patterns.'

As outlined in section 5.3.2 of this report, AEMO raised concerns that the use of 7 years of historical data may overestimate the contribution of wind farms during the conditions of a 1-in-10 year peak demand event.

As outlined in section 5.3.2 of this report, Alinta Energy raised concerns that predicting peak demand conditions and predicting the performance of Intermittent Generators under these conditions would be 'highly fraught and arbitrary'. Alinta Energy considered that the data presented in the Rule Change Proposal shows that these conditions, and their impact on the output of Intermittent Generators, cannot be reliably predicted.

The Rule Change Panel agrees that there are issues with using historical data, as outlined by the ERA and AEMO. However, the Rule Change Panel agrees with Alinta Energy that simulated demand and performance of Intermittent Generators for expected peak demand conditions would be highly arbitrary. The Rule Change Panel considers that any simulation of system demand and the associated performance of Intermittent Generators would be extremely complex and introduce more uncertainty about the outcomes than the use of historical data. The Rule Change Panel has reached this conclusion for the following reasons:

- both system demand and the output of Intermittent Generators are influenced by many different drivers, the effect of which is difficult to simulate;
- the drivers for system demand and output of intermittent generation are overlapping but not the same; and
- some of the drivers for system demand and output of Intermittent Generators are correlated.

The Rule Change Panel's draft decision is to adopt the use of historical data for system demand and performance of Intermittent Generators but to amend the ERA's proposal for the use of system demand, as outlined in the remainder of this section 6.1.5.

Extending the Reference Period from 5 to 7 Years

The ERA proposes to increase the Reference Period for the RLM from 5 years to 7 years.

The Rule Change Panel considers that the length of the Reference Period has to strike a balance between:

- increasing the data set to try to capture a larger number of peak system demand events are captured, noting that such events are rare in the SWIS; and
- avoiding the effect of changes to the demand mix over time that may result in older data being less representative of the future system demand.

The Rule Change Panel acknowledges that any chosen length for the Reference Period is arbitrary. However, the Rule Change Panel considers that, as long as the historical data is adjusted for the increase in installed capacity of small scale PV (as outlined later in this section 6.1.5), 7 years is a reasonable length for the Reference Period and strikes a reasonable balance between the factors listed above. The Rule Change Panel acknowledges that any chosen length for the Reference Period is arbitrary.

The Rule Change Panel notes that an increase in the length of the Reference Period to 7 years means that Market Participants will have to provide independent expert reports for a longer period before the full operational date of the Facility or its latest upgrade. In addition, Market Participants will have to provide independent expert reports for such Facilities for more Reserve Capacity Cycles.

No concerns have been raised by the MAC or in submissions received in the first submission period about the proposed length of the Reference Period or about the provision of additional independent expert reports.

The Rule Change Panel's draft decision is to adopt a 7-year Reference Period.

Adjusting the Historical System Demand for DER

The ERA proposes to adjust system demand to reflect the expected contribution of DER in the relevant Capacity Year.

The Rule Change Panel has consulted with AEMO about the feasibility and practicality of the DER adjustment. AEMO has confirmed that its forecast of the 1-in-10 year peak demand and the expected annual consumption for the relevant Capacity Year account for the increased uptake of DER. The 2020 WEM ESOO indicates that the generation from small scale PV:

- is reducing the system peak demand; and
- is shifting the time of the daily peak system demand to later in the day.

AEMO notes in the 2020 WEM ESOO that it expects the strong growth of small scale PV capacity in the SWIS to continue.

The Rule Change Panel agrees with the ERA and AEMO that the continuous increase of installed capacity of small scale PV reduces the representativeness of historical system demand as a forecast of future system demand.

The Base Model accounts for the uptake of small-scale PV by adjusting the historical demand for the level of small scale PV installed in April 2020. To assess whether the continued increase of installed capacity of small-scale PV affects the ELCC of the Fleet, the Rule Change Panel adjusted the Base Model to remove the DER adjustment. To reduce the complexity of the modelling scenarios, the Rule Change Panel did not account for the estimated further increase of installed small scale PV that would occur up to the start of the relevant Capacity Year.

AEMO provided the Rule Change Panel with the following data for this assessment:

- solar capacity factor traces for each Trading Interval in the assessed Reference Period, sourced from SolCast;[20]
- the installed capacity of small scale PV larger than 100 kW for each calendar month in the assessed Reference Period (excluding solar farms with Capacity Credits), sourced from the Australian PV Institute; and
- the installed capacity of small scale PV smaller than 100 kW for each calendar month in the assessed Reference Period, sourced from the Clean Energy Regulator.

The Rule Change Panel calculated the ELCCs of the Fleet using the Base Model (which adjusts for DER) and the adjusted Base Model (which does not adjust for DER) as follows:

- ELCC for the whole 7-year Reference Period; and
- ELCC for each 12-month period in the Reference Period (from 8:00 AM of 1 April of one year to 8:00 AM on 1 April of the next year).

Figure 2: Comparison of ELCC for the 7-year Reference Period and for each 12-month period in the Reference Period, with and without adjustment for small scale PV

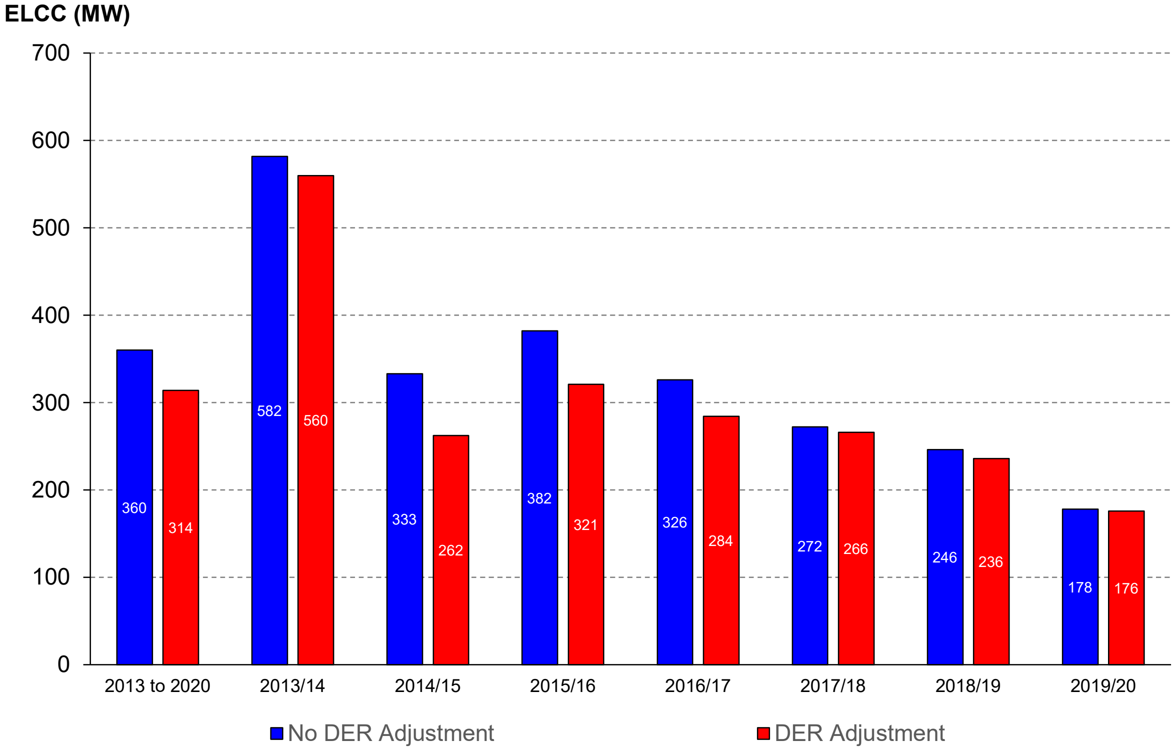

Figure 2 indicates that the Fleet ELCC for the 7-year Reference Period and for the earlier of the 12-month periods is affected by the increase of installed small scale PV capacity (with possible exception of 2013/14). The Rule Change Panel considers that Figure 2 indicates that it is important to account for the uptake in small scale PV in the ELCC calculations.

20 SolCast is a global provider solar irradiance data and other related data. AEMO uses this data for its forecast of the 1-in-10 year peak demand and the expected annual consumption of the Capacity Years in the Long Term PASA Horizon.

The Rule Change Panel notes that the ERA does not propose to limit the adjustment of historical system demand for the impact of DER to only consider small scale PV. The Rule Change Panel agrees with the ERA that the DER adjustment should ideally consider all forms of DER. However, the Rule Change Panel considers that:

- the adjustment for small scale PV is relatively well understood and practical to implement;
- the adjustment for small scale PV increases the likelihood that the system demand used to determine the ELCC will reflect the future system demand;
- the adjustment for other DER, such as storage or electric vehicles, is more complex and uncertain due to a lack of historical data in the SWIS; and
- the adjustment for other DER would reduce the practicability and increase the uncertainty of the DER adjustment.

No concerns were raised by the MAC or in submissions received in the first submission period about the proposed DER adjustment of the historical demand.

The Rule Change Panel's draft decision is to adopt the proposal to adjust historical demand for the uptake of small scale PV, but not for other DER. The Rule Change Panel recommends that the possibility of adjusting the historical demand for other DER should be assessed in the next review of the RLM.

Scaling Historical System Demand to Reflect the 1-in-10 Year Peak Demand Forecast

In Appendix 3 of its Rule Change Proposal, the ERA notes its concern that the observed historical demand in the SWIS over the 7-year modelling horizon had been lower than any of AEMO's relevant 1-in-10 year peak demand forecasts.

The ERA also stated the following on page 17 of the Rule Change Proposal:

> 'The relatively low level of observed demand in the SWIS could create a bias in the estimate of the capacity value of intermittent generators. This is because the capacity value estimated for the intermittent generators is determined by loss of load probability, which is dependent on system capacity margin in every trading interval over the historical years sampled. System margin is the difference between supply and demand. If observed demand is lower than that is expected to happen in a year with extremely high demand, the estimate of capacity value could be biased. This allowed for the capacity value of intermittent generators to be partly determined by their available capacity during periods of low supply capacity and relatively low demand.
>
> The ERA's expectation was that this possible bias would be small and at the time the ERA did not recommend using a scaled demand profile. This was to avoid any subjective scaling of the observed system demand and keep the method as simple as possible. The ERA also explained that it would review this aspect of the method in the next review of the RLM.
>
> At the MAC meeting on 20 October 2020, AEMO stated that the ERA did not address AEMO's concern about the ability of the proposed method to accurately forecast the capacity value of intermittent generators based on weather conditions during peak demand levels that are considered in the planning criterion.'

To address these concerns, the ERA proposed to scale the historical system demand as follows:

- scale the peak demand in each 12-month period of the Reference Period to equal the estimated 1-in-10 year peak demand for the relevant Capacity Year; and
- scale the total consumption in each 12-month period of the Reference Period to equal the expected annual consumption for the relevant Capacity Year.

As outlined in section 5.3.2 of this report, AEMO raised concerns that the proposed scaling may overestimate the capacity value of wind farms.

The Rule Change Panel agrees with AEMO's concerns about the scaling of the historical demand. As outlined in section 6.1.5 of this report, the Rule Change Panel considers that the system demand and the output of the Intermittent Generators are influenced by many of the same drivers, and weather in particular. Scaling the system demand to match a peak demand scenario implies that the conditions during the affected Trading Intervals would have been different to what they were (e.g. higher air temperature). Different underlying conditions for historical Trading Intervals would be quite likely to lead to a different output from Intermittent Generators. As outlined in section 6.1.5 of this report, the Rule Change Panel considers that it is not appropriate to adjust the historical output for Intermittent Generators to account for this effect. Therefore, the Rule Change Panel considers it inappropriate to scale the historical system demand, as proposed by the ERA.

The Rule Change Panel considers that the historical system demand should ideally be adjusted for the growth of underlying demand. However, the Rule Change Panel considers that it would be difficult for AEMO to predict the effect of the underlying demand growth on system demand in each Trading Interval because of the diverse factors that influence demand. The Rule Change Panel considers that further analysis is needed to assess the effect of the underlying demand growth, that it would be inappropriate to delay the processing this Rule Change Proposal to undertake such analysis, and that adjusting the historical system demand for the underlying demand growth would reduce the practicability and increase the uncertainty of the RLM.

The Rule Change Panel's draft decision is to reject the scaling of the historical demand to reflect the 1-in-10 year peak demand forecast. The Rule Change Panel recommends that the possibility of adjusting the historical demand for the growth of the underlying demand should be assessed in the next review of the RLM when more time is available for the required assessment.

6.1.6 Target LOLE

The ERA proposed to apply a target LOLE of 4 hours in 10 years to reflect the Planning Criterion. The ERA provides the following rationale for this proposal on pages 64 and 65 of its Rule Change Proposal:

> 'The planning criterion in the SWIS explicitly specifies an expected frequency limit of one loss of load event in 10 years, without any limitation on the duration or magnitude of such loss of load events. This frequency requirement can be translated to a LOLE measure by assuming an expected duration for the loss of load event. For example, if the expected loss of load event has a duration of four hours, the LOLE equivalent of one expected shortfall event in 10 years would be four hours in 10 years.
>
> The proposed method uses a half-hourly LOLE to measure the adequacy risk of the system. A half-hourly LOLE is a measure of the expected number of half-hours during a

particular period during which load is expected to exceed resources' capacity. Interpreting the one-in-ten criterion using this measure would allow for some specified cumulative hours of hourly LOLE every 10 years. This measure, among other measures of LOLE, uses more data but accounts for both frequency and duration, providing a more precise indication of the expected level of reliability. The hourly LOLE can be converted to a loss of load probability, which provides the probability that supply will be inadequate to serve demand over a particular period. Nevertheless, the half-hourly LOLE does not account for the magnitude of a shortfall.

Use of LOLE is consistent with the common practice in system adequacy analysis, which commonly uses LOLE or expected unserved energy as the measure of system adequacy. Among common interpretations of the one-in-ten year criterion the half-hourly LOLE provides the most precise indication of the expected level of reliability.

…

To determine the target level of LOLE consistent with the planning criterion the ERA considered the design of the planning criterion and other relevant clauses in the market rules, practice in other jurisdictions and results of sensitivity scenarios.

The [Pennsylvania-New Jersey-Maryland Interconnection (**PJM**)] in the United States considers a LOLE=24 hours in 10 years (or 2.4 hours per year) when estimating the ELCC of resources. The Great Britain electricity system uses a system adequacy target of LOLE=30 hours per 10 years (or 3 hours per year). It recently used this target level to estimate the equivalent firm capacity of storage resources. The National Grid's assessment of the duration of possible loss of load events showed that the bulk of the distribution of the duration of loss of load events were between 0.5 and four hours.

The electricity system in Ireland uses a system adequacy target of LOLE=80 hours per 10 year (or eight hours per year). France's electricity system targets LOLE=3 hours per year. The Netherlands' electricity system targets LOLE=4 hours per year.

EPWA's proposed changes to the market rules specify a requirement for electric storage resources to be eligible for reserve capacity certification. This requirement sets the 'electric storage resource obligation duration' to four hours. This represents the duration over which storage facilities receiving capacity credits must sustain their maximum discharge capacity.

AEMO determines the time window of this obligation period, which is based on AEMO's expectation of periods with the highest reliability stress. Under the proposed certification method for storage facilities – referred to as the linear derating method – a storage facility that can sustain its maximum discharge capability (in MW) during the four-hour obligation window would receive 100 per cent of its maximum discharge capability as its capacity value.

This implies that the expected duration of a typical loss of load event in the SWIS is four hours and Electric Storage Resources' capacity over the four-hour obligation period helps to avoid the occurrence of loss of load. This expectation of the duration of a typical loss of load event is consistent with the National Grid's assessment of possible loss of load durations for the Great Britain electricity system.

This expectation of duration of the loss of load event in the SWIS suggests using a target LOLE=4 hours per 10 years (or 0.4 hours per year) in the proposed RLM. In comparison with other electricity systems around the world, this is an extremely low level of LOLE.'

As outlined in section 5.3.4 of this report, in their first period submissions:

- Alinta Energy considered that the 4 hours ESROD is not based on the Planning Criterion but on the technical limitations of ESR. Alinta Energy considered that the 14 hours of Peak Trading Intervals in each Trading Day used to determine the fuel requirement for Scheduled Generators is a more appropriate indicator of the WEM's target LOLE.
- Synergy suggested that the target LOLE of 4 hours in 10 years should be reassessed in the next review of the RLM.

The Rule Change Panel disagrees with the ERA's interpretation that the Planning Criterion translates into one loss of load event per 10 years. The Rule Change Panel considers that the Planning Criterion does not specify a target LOLE at all.

As outlined in section 6.1.2 of this report, the Rule Change Panel considers that the Defined Scenario in the Planning Criterion (see section 4.5 of the WEM Rules) sets the amount of Capacity Credits AEMO must procure, based on its 1-in-10 year peak demand forecast and the Reserve Margin; but does not translate into a target LOLE.

The Rule Change Panel considers that the ERA's proposed target LOLE of 4 hours in 10 years and Alinta Energy's proposed target LOLE of 14 hours in 10 years is neither stated in nor implied by the Planning Criterion, and is therefore inconsistent with the Planning Criterion.

The Rule Change Panel notes that the ERA did not propose to use an initial target LOLE in its first Pre-Rule Change Proposal, and instead proposed to use the observed LOLE based on the fleet of non-Candidate Facilities and system demand. However, the ERA noted in its Rule Change Proposal that not using an initial target LOLE may undervalue the contribution of the Candidate Facilities because the observed LOLE in the SWIS is typically very low, partly due to excess Capacity.

The Rule Change Panel agrees with the ERA that the observed LOLE based on the fleet of non-Candidate Facilities may undervalue the contribution of the Candidate Facilities when the Capacity Credits of non-Candidate Facilities exceeds the Reserve Capacity Requirement. The Rule Change Panel further considers that this approach may overvalue the contribution of Candidate Facilities if the Capacity Credits from the fleet of non-Candidate Facilities would be less than the Reserve Capacity Requirement. This is because:

- the observed LOLE will be lower if more capacity from non-Candidate Facilities is accounted for in the COPT; and
- a lower LOLE may increase the impact of each Trading Interval with a higher LOLP in which the Fleet may not perform well.[21]

The Rule Change Panel notes that the penetration of Intermittent Generation was very low when the Planning Criterion was first designed and during each of the reviews of the Planning Criterion in 2006 and 2012. Therefore, the Planning Criterion is designed on the assumption that the Reserve Capacity Target will be met with most of the Capacity Credits

[21] This is because, if the Fleet does not perform well during any of the Trading Intervals with high LOLP, then the impact on the ELCC will be higher for lower observed LOLEs.

assigned to Scheduled Generators and only a few assigned to Intermittent Generators and DSPs.[22]

The Rule Change Panel considers that, while the Planning Criterion does not specify a target LOLE, the following can be implied:

(1) if AEMO was to procure the exact amount of Capacity Credits set by the Reserve Capacity Requirement from only Scheduled Generators, the resulting system reliability would be acceptable; and

(2) if AEMO was to instead procure the exact amount of Capacity Credits set by the Reserve Capacity Target with a proportion coming from Intermittent Generators, the resulting system reliability would not be acceptable because the resulting system reliability would be lower than that implied under (1).

Therefore, the Rule Change Panel considers that, instead of scaling the demand to a target LOLE, it is more appropriate to adjust the COPT so that the total number of Capacity Credits of all Facilities in the COPT equals the Reserve Capacity Requirement. The Rule Change Panel considers that, in such a scenario, the observed LOLE would reflect the LOLE implied by the Planning Criterion for any reference system demand.

The Rule Change Panel considers that the most transparent and non-arbitrary approach to creating such a COPT (**Amended COPT**) is as follows:

(1) identify all relevant non-Candidate Facilities for the COPT;

(2) determine the percentage by which the Capacity Credits of all Facilities in the COPT differ from the Reserve Capacity Requirement; and

(3) amend the capacity of each Facility in the COPT by the percentage determined under step (2).

The Rule Change Panel notes that this approach is only appropriate for as long as only a small share of capacity in the COPT is provided by DSPs and ESRs. Future RLM Reviews should consider penetration of DSPs and ESRs to assess if and when this approach for setting the COPT should be reconsidered.[23]

To assess how the ERA's proposed 4 hours in 10 years target LOLE compares to the observed LOLE, based on the current COPT and the Amended COPT, the Rule Change Panel adjusted the Base Model to remove the initial scaling of the system demand to reach the target LOLE of 4 hours in 10 years, and used the following COPTs:

- Adjusted Model 1: the original COPT; and
- Adjusted Model 2: the Adjusted COPT.

22 This is supported by Market Reform's final report on the 2008 review of the Planning Criterion, which states (page 44):

> 'Intermittent generation may also be a source of unreliability in a system depending on the level of penetration of wind/solar generation and their variability during peak. Based on limited entry of wind in the SWIS, it is currently not a significant issue. From the limited data available, intermittent/wind generation across all firms in the SWIS forms less than 50 MW on average compared to an average demand in excess of 2,000 MW during 2010/11. The variability of intermittent generation is significant with a standard deviation of 25 MW, but given its low level does not amount to a major contingency at present.'

23 The share of DSPs in the CRC was around 5% at the time of the last review of the Planning Criterion (2012) and was expected to increase to 8% in the next two years after the review.

The Rule Change Panel calculated the LOLE for the whole 7-year Reference Period and for each 12-month period in the Reference Period using Adjusted Model 1 and Adjusted Model 2, as shown in Table 2.

Table 2: Comparison of the ERA's proposed Target LOLE with the observed LOLE based on the original COPT and the Adjusted COPT[24]

Assessment Period and peak demand of the period	Base Model (4 hours in 10 years LOLE, original COPT)	Adjusted Model 1 (Observed LOLE, Original COPT)	Adjusted Model 2 (Observed LOLE, Adjusted COPT)
Whole Reference Period 3,948 MW peak demand	5.6	0.024329	0.172360
2013/14 3,601 MW peak demand	0.8	0.000186	0.001610
2014/15 3,634 MW peak demand	0.8	0.000200	0.001664
2015/16 3,948 MW peak demand	0.8	0.016713	0.120076
2016/17 3,447 MW peak demand	0.8	0.000026	0.000230
2017/18 3,581 MW peak demand	0.8	0.000081	0.000698
2018/19 3,256 MW peak demand	0.8	0.000001	0.000013
2019/20 3,913 MW peak demand	0.8	0.007122	0.048078

Table 2 shows that:

- the ERA's proposed target LOLE of 4 hours in 10 years is markedly higher than both observed LOLEs produced by the adjusted models;
- the difference between the ERA's proposed target LOLE of 4 hours in 10 years and the two observed LOLEs is the greatest for the whole 7-year Reference Period;
- both observed LOLEs differ across the different assessment periods; and
- the observed LOLEs are higher for assessment periods with higher peak demand.

The Rule Change Panel considers that this indicates that the ERA's proposed 4 hours in 10 years target LOLE is inconsistent with the Planning Criterion and is therefore inappropriate.

The Rule Change Panel considers that, to be consistent with the Planning Criterion, the LOLE used to determine the ELCC of the Fleet must differ depending on the system stress in the assessment period.

24 Columns 2 to 3 in Table 2 are measured in Trading Intervals.

To assess the effect of the different target LOLE's on the Fleet ELCC, the Rule Change Panel calculated the ELCC of the Fleet for the 7-year Reference Period and for each 12-month period in the reference period using the Base Model, Adjusted Model 1 and Adjusted Model 2. This assessment is shown in Figure 3.

Figure 3: Comparison of the Fleet ELCC for the ERA's proposed Target LOLE, the observed LOLE based on the original COPT, and the observed LOLE based on the Adjusted COPT

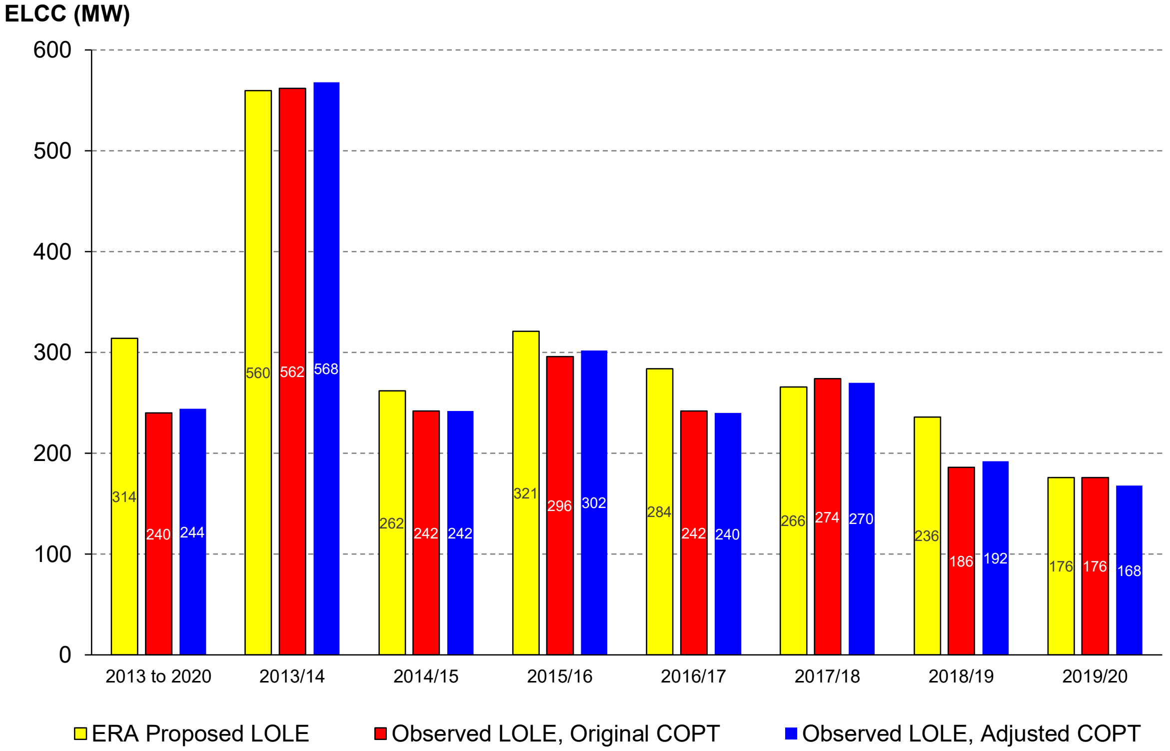

Figure 3 shows that:

- The Fleet ELCC for the whole 7-year Reference Period based on the observed LOLE (either using the original COPT or the Adjusted COPT) is markedly lower than the Fleet ELCC based on the ERA's proposed target LOLE. The Rule Change Panel believes that this is caused by the material difference between the target LOLE set by the ERA and the observed LOLEs.
- The Fleet ELCCs for the whole 7-year Reference Period and for the individual 12-month periods within the Reference Period are similar to the Fleet ELCCs based on the observed LOLE using either the original COPT or the Adjusted COPT.
- The Fleet ELCC for the individual 12-month periods within the Reference Period, based on the ERA's proposed target LOLE, is higher for 4 of the 12-month periods (2014/15, 2015/16, 2016/17, and 2018/19) and slightly lower or similar for 3 of the 12-month periods (2013/14, 2017/18, and 2019/20) than the Fleet ELCC based on the two observed LOLEs. The Rule Change Panel considers that this is likely because the COPT is not linear. Instead, several rows of the COPT will have the same Outage Probability because of the size of the Facilities in the COPT and the assumption that a Facility is either fully available or on a full Forced Outage.

The Rule Change Panel considers that this indicates that the 4 hours in 10 year target LOLE tends to overestimate the Fleets contribution to system reliability.

Therefore, the Rule Change Panel's draft decision is to reject the proposed 4 hours in 10 years target LOLE and to instead set the target LOLE as the observed LOLE based on the Adjusted COPT.

The Rule Change Panel notes that its proposed target LOLE results in a lower Fleet ELCC for the 7-year Reference Period[25] than the target LOLE proposed by the ERA. The Rule Change Panel has not calculated the Fleet ELCC based on Alinta Energy's proposed target LOLE, but considers it likely that the Rule Change Panel's proposed approach will also result in a lower Fleet ELCC for the 7-year Reference Period than the target LOLE proposed by Alinta Energy. Optimally, a review of the Planning Criterion would have been completed before the RLM Review was commenced and this Rule Change Proposal was submitted. A review of the Planning Criterion could have identified an appropriate target LOLE for the WEM. However, such a change would most likely also require additional changes to the RCM, and reviewing the Planning Criterion or implementing an explicit target LOLE is outside the scope of this Rule Change Proposal. Without a policy direction from Government regarding the appropriate target LOLE, the Rule Change Panel does not believe that there is any basis for it to choose a target LOLE different from what is supported by the current Planning Criterion.

6.1.7 Reference Period to set the Selected ELCC of the Fleet

The ERA proposes to determine the Selected ELCC of the Fleet for a Reserve Capacity Cycle as the lower value of:

- the Median ELCC; and
- the Whole Period ELCC.

As noted in section 5.3.3 of this report:

- AEMO raised concerns about the use of the Median ELCC and suggested to instead use the average of the 2 lowest 12-monthly ELCCs; and
- Alinta Energy and Synergy raised concerns about using the lower of the 2 values and suggested to instead use the Median ELCC.

The Rule Change Panel agrees with AEMO that using the Median ELCC may be inconsistent with the Planning Criterion. The Rule Change Panel considers that the ELCC of each period depends on the following factors:

- the observed LOLE in the period;
- which Trading Intervals are most relevant in determining the observed LOLE; and
- the performance of the Fleet during the Trading Intervals that are most relevant in determining the observed LOLE.

The Rule Change Panel considers that Trading Intervals with the highest LOLP are the most relevant in determining the Fleet's contribution to system reliability.

The Rule Change Panel notes that, based on the set up of the COPT (where the outage probabilities for the non-Candidate Facilities are the same for all Trading Intervals), the Trading Intervals with the highest LOLP are also the Trading Intervals with the highest

25 Noting that the Rule Change Panel proposes to use the seven-year Reference Period as the basis for the RLM, as outlined in section 6.1.7 of this report.

system demand. To assess the influence of the peak demand on the Fleet ELCC for the period, the Rule Change Panel compared:

- the Fleet ELCCs for the whole 7-year Reference Period and for each 12-month period in the Reference Period, based on the Alternative COPT using Amended Model 2 (described in section 6.1.6 of this report); and
- the DER adjusted peak system demand for the whole 7-year Reference Period and for each 12-month period in the Reference Period.

Figure 4 shows the results of this comparison.

Figure 4: Comparison of the Fleet ELCC and the DER adjusted peak system demand

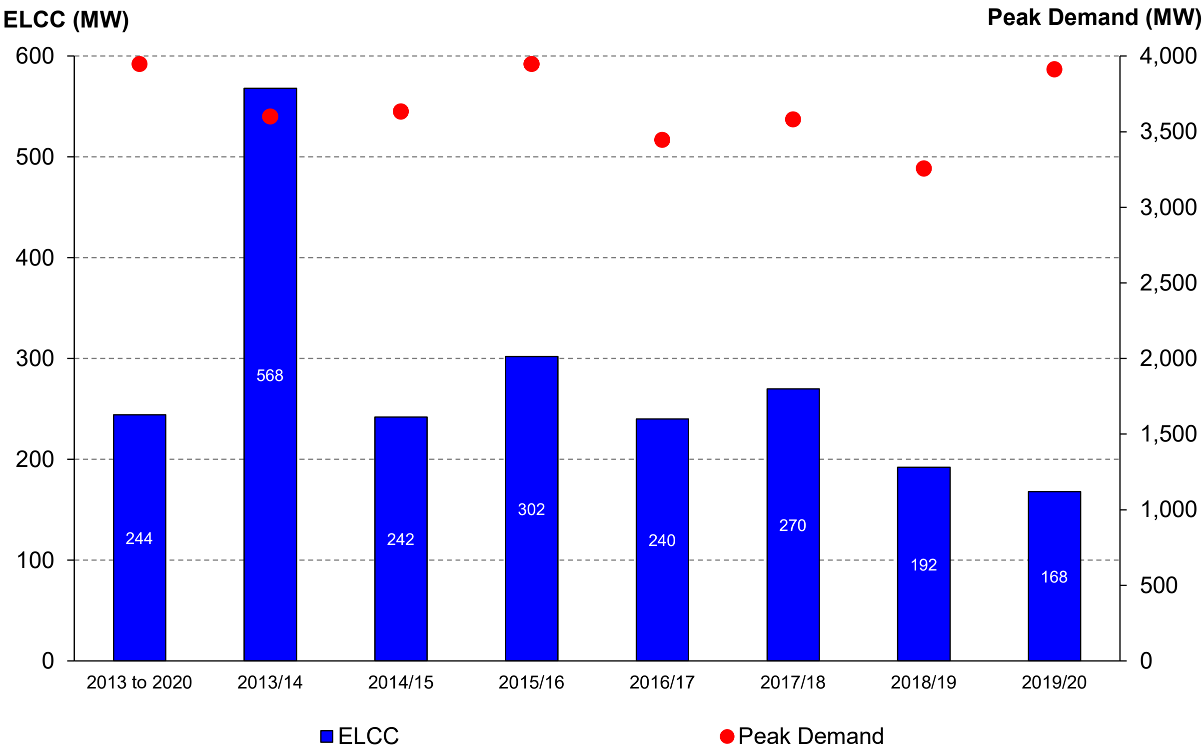

Figure 4 shows that, peak system demand and the Fleet ELCC do not appear to be related. For example:

- the 12-month period from 1 April 2018 to 31 March 2019 has the second lowest Fleet ELCC and the lowest peak system demand; but
- the 12-month period from 1 April 2019 to 31 March 2020 has the lowest Fleet ELCC and the second highest peak system demand.

As noted in section 6.1.6 of this report, the Rule Change Panel considers that the performance of the Fleet is more relevant for periods of high system stress than for periods of low system stress.

Therefore, the Rule Change Panel considers that it would be inappropriate to determine the Selected ELCC of the Fleet based on:

- the ERA's proposal to use the lower of the Fleet's Whole Period ELCC and the Fleet's Median ELCC;

- AEMO's suggestion to use the average of the two lowest 12-monthly ELCCs; or
- Alinta Energy's and Synergy's suggestion to use the Median ELCC.

This is because all of the above proposals are based on the arbitrary selection of a Fleet ELCC and may set the Selected ELCC of the Fleet based on the Fleet performance during Trading Intervals that are irrelevant for system reliability and because the Fleet's performance may be ignored during Trading Intervals that are relevant for system reliability.

The Rule Change Panel considers that the Whole Period ELCC best reflects the Fleet's performance because:

- this period will include all Trading Intervals that are most relevant for system reliability; and
- the performance of the Fleet during these relevant Trading Intervals will drive the Whole Period ELCC of the Fleet.

The Rule Change Panel's draft decision is to determine the Selected ELCC of the Fleet as its Whole Period ELCC. Where not stated otherwise, the Selected ELCC of the Fleet will be referred to as the Fleet ELCC in the remainder of this report.

6.1.8 Allocation of the Fleet ELCC to Individual Facilities

As outlined in section 4.1.2 of this report, the ERA proposes to allocate the Fleet ELCC:

- first between Technology Groups based on their Whole Period ELCCs; and then
- between the individual Candidate Facilities in the Technology Groups based on their relative average performance during the Trading Intervals with the highest system load and highest LSG from each of the 12-month periods in the Reference Period.

As noted in section 5.3.6 of this report, Alinta Energy raised concerns about the allocation of the Fleet ELCC to Technology Groups.

The Rule Change Panel acknowledges that the allocation of the Fleet ELCC between Technology Groups is used in other jurisdictions. However, the Rule Change Panel notes that this approach is based on the assumption that the performance of the Facilities in each Technology Group is positively correlated.

The performance of Intermittent Generators depends on the applied technology and the weather at the location of the Facility. Accordingly, it is likely that the performance of Facilities of the same technology in similar locations will be well correlated but that the performance of Facilities of differing technology or in different locations will not. For this reason, some other jurisdictions (such as PJM and the Midcontinent Independent System Operator (**MISO**) in the US) divide their fleet of intermittent generators into groups by both technology and region.

In its first period submission, AEMO indicated that the performance of wind farms in the south of the SWIS differs from the performance of wind farms in the north.

The Rule Change Panel notes that the wind farms in the SWIS are spread over very different locations and in different climates, with up to 1,000 km distance between them. The Rule Change Panel considers it inappropriate to assume that weather conditions, and in particular wind conditions, in these locations would be similar at every point in time including during Trading Intervals with high system stress.

Therefore, the Rule Change Panel considers that allocating the Fleet ELCC between Technology Groups before allocating it between the individual Candidate Facilities is inappropriate.

As outlined in sections 6.1.6 and 6.1.7 of this report, the Rule Change Panel considers that the performance of the Candidate Facilities during the Trading Intervals with the highest system stress is the most important factor for the Facilities' contribution to system reliability. The Rule Change Panel considers that:

- as outlined in section 6.1.5 of this report, extremely high demand periods have occurred very rarely in the SWIS; and
- as outlined in section 6.1.7 of this report, a period of high system stress does not occur in each of the 12-month periods in the Reference Period.

Therefore, the Rule Change Panel considers that the performance of the Candidate Facilities is irrelevant during most of the 168 Trading Intervals that the ERA proposes to consider for the allocation of the Fleet Relevant Level to the individual Candidate Facilities.

The Rule Change Panel notes that the PJM has applied to the Federal Energy Regulatory Commission (**FERC**) (US) to implement a method to allocate the fleet ELCC to the relevant individual facilities called the 'Delta Method'.[26] The Rule Change Panel understands that PJM is currently planning to apply the Delta Method from mid-2021.

The Delta Method allocates the fleet ELCC to the individual facilities (or to facility groups) based on their marginal ELCC, as follows:

- for each individual facility, calculate:
  - the First-In ELCC, which is the ELCC of the individual facility excluding the other facilities (i.e. as if the individual facility was the first facility used to meet system demand); and
  - the Last-In ELCC, which is the ELCC of the individual facility including the other facilities (i.e. as if the other facilities have already reduced demand);
- determine the Interactive Effect as the fleet ELCC less the sum of all facilities' Last-In ELCCs;
- determine the Delta for each facility as its First-In ELCC less its Last-In ELCC;
- for each facility, determine its Interaction Effect Share as the facility's Delta multiplied by the Interactive Effect and divided by the sum of all Deltas; and
- for each facility determine the ELCC as its Last-In ELCC plus its Interaction Effect Share.

The Rule Change Panel considers that neither the First-In ELCC nor the Last-In ELCC alone appropriately describes the capacity value of a Facility but that both values together characterise interactions within a Fleet of Facilities. If a Facility's Last-In ELCC exceeds its First-In ELCC, its contribution to system reliability is greater when considered in the context of the entire Fleet than on its own. On the other hand, if a Facility's Last-In ELCC is lower than its First-In ELCC, its contribution to resource adequacy is lower in the context of the entire portfolio than on its own.

[26] Information on this FERC process is available at https://www.pjm.com/directory/etariff/FercDockets/6010/20210301-er21-278-001.pdf.
A paper explaining the Delta Method by Energy + Environmental Economics (**E3**) is available on E3's website at https://www.ethree.com/elcc-resource-adequacy/.

Under the Delta Method, each resource's Last-In ELCC is adjusted either upward or downward according to the difference between its Last-In and First-In ELCCs, in a manner such that the sum of accredited ELCCs to all facilities equals the ELCC of the Fleet. This method will naturally result in an accredited ELCC for each resource in between its First-In ELCC and Last-In ELCC.

The Rule Change Panel considers that this approach ensures that the interactive effects between a Facility and the Fleet are credited to facilities in a manner that captures the effects of their interactions on resource adequacy.

To assess the effect of applying the Delta Method in the SWIS, the Rule Change Panel has further amended the Amended Model 2 (described in section 6.1.6 of this report) to replace the allocation of the Fleet Relevant Level proposed by the ERA with the Delta Method.

To account for modelling restrictions, this amended Model groups Facilities with a Nameplate Capacity below 10 MW into one of the following groups[27]:

- biogas, and
- small wind and solar farms.

The Relevant Levels for the individual Facilities in these groups are determined by allocating the respective group ELCC between the Facilities in the group based on the Facilities' relative performance in:

- the 50 Trading Intervals with the highest LOLP; and
- the 50 Trading Intervals with the highest LOLP excluding the contribution of all other Candidate Facilities from the system demand.

The Rule Change Panel calculated the Relevant Level for each Candidate Facility for the 7-year Reference Period, based on the Alternative COPT and allocating the Relevant Level as follows:

- using the allocation methodology proposed by the ERA; and
- using the Delta Method.

Figure 5 compares the results of these calculations for 2020 with the current RLM for 2020, Figure 6 makes the same comparison for biogas and small wind and solar Facilities, and Table 3 provides the data points shown in Figures 5 and 6.

[27] This is because the COPT in the model uses increments of 1 MW and not 0.1 MW.

Figure 5: Comparison of the Relevant Levels allocated to Candidate Facilities under the current RLM, the ERA's proposed allocation method and the Delta Method (large Facilities and groups of small Facilities)

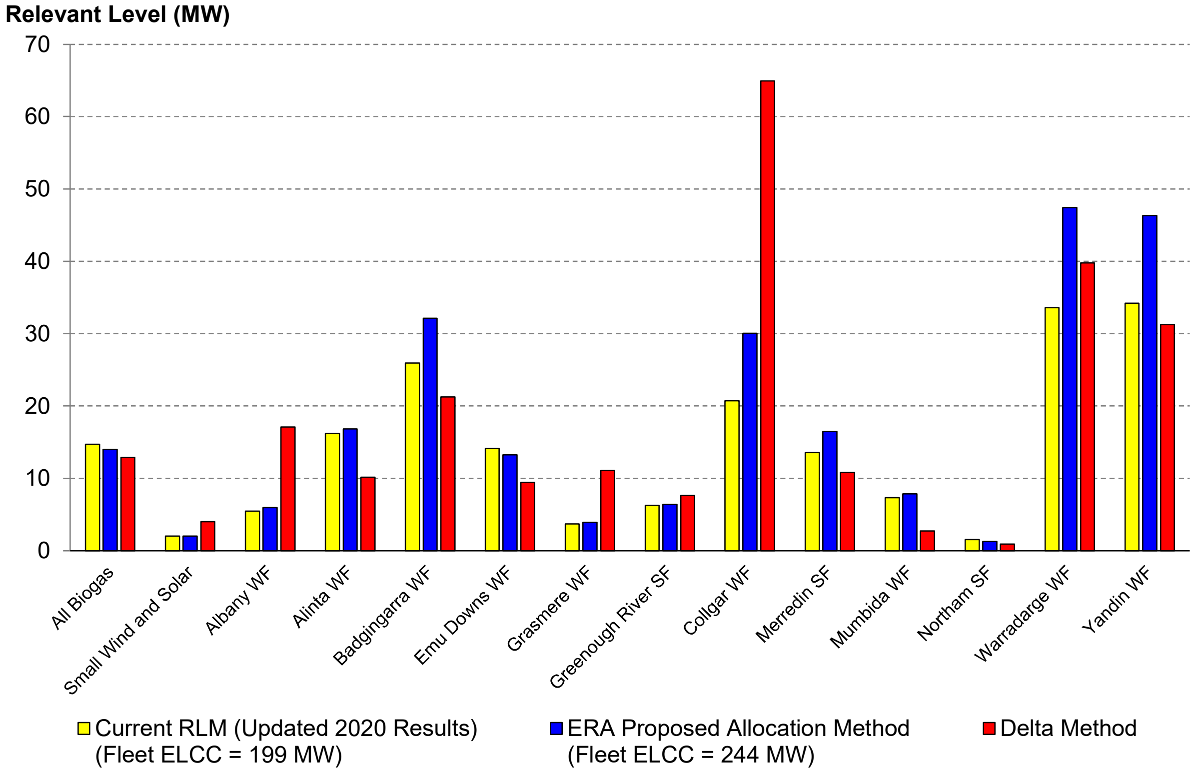

Figure 6: Comparison of the Relevant Levels allocated to Candidate Facilities under the current RLM, the ERA's proposed allocation method and the Delta Method (biogas and small wind and solar Facilities)

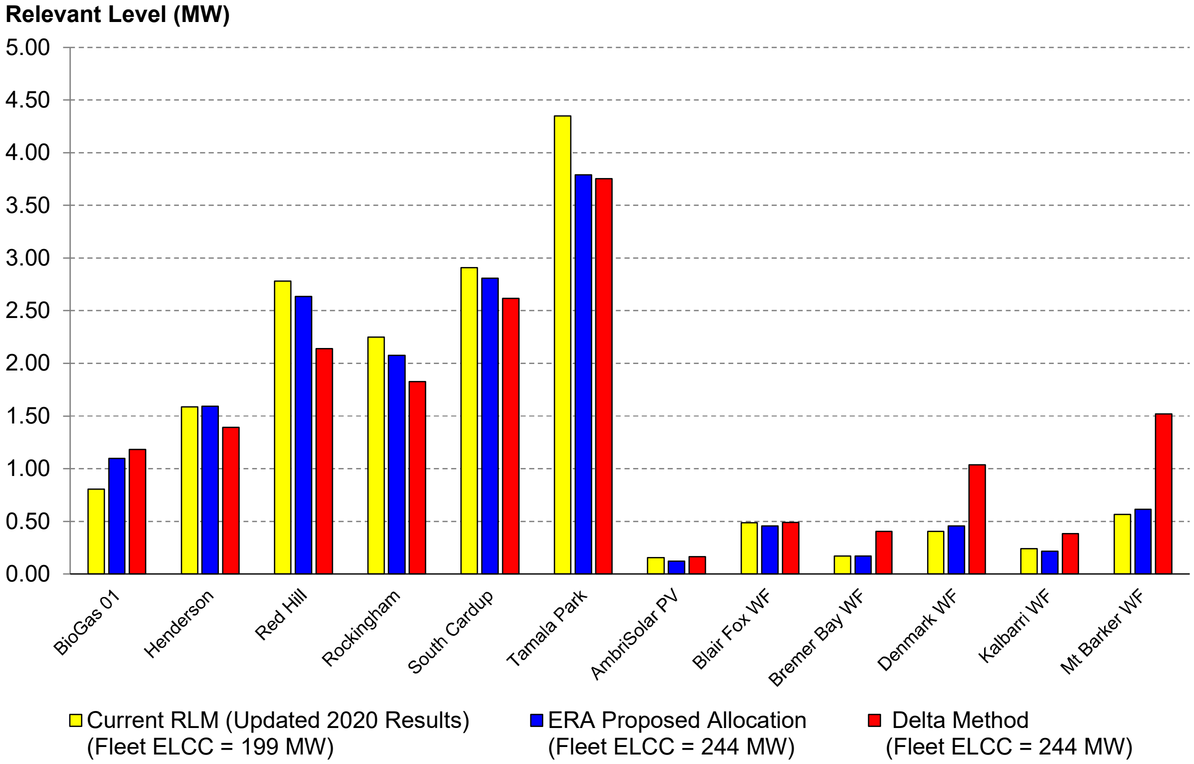

Table 3: Comparison of the Relevant Levels allocated to Candidate Facilities under the current RLM, the ERA's proposed allocation method and the Delta Method

Facility	Current RLM (MW)	ERA Proposed Allocation (MW)	Delta Method (MW)
All Biogas	14.69	14.00	12.90
• BioGas 01	0.81	1.10	1.18
• Henderson	1.59	1.59	1.39
• Red Hill	2.78	2.64	2.14
• Rockingham	2.25	2.08	1.83
• South Cardup	2.91	2.81	2.62
• Tamala Park	4.35	3.79	3.75
Small Wind and Solar	2.02	2.03	4.00
• AmbriSolar PV	0.16	0.12	0.16
• Blair Fox WF	0.49	0.46	0.49
• Bremer Bay WF	0.17	0.17	0.40
• Denmark WF	0.40	0.46	1.04
• Kalbarri WF	0.24	0.22	0.38
• Mt Barker WF	0.57	0.61	1.52
Albany WF	5.48	5.97	17.10
Alinta WF	16.19	16.85	10.20
Badgingarra WF	25.94	32.12	21.30
Emu Downs WF	14.15	13.25	9.40
Grasmere WF	3.69	3.93	11.10
Greenough River SF	6.28	6.40	7.60
Collgar WF	20.74	30.03	64.90
Merredin SF	13.54	16.49	10.80
Mumbida WF	7.30	7.86	2.70
Northam SF	1.55	1.30	0.90

Facility	Current RLM (MW)	ERA Proposed Allocation (MW)	Delta Method (MW)
Warradarge WF	33.61	47.43	39.80
Yandin WF	34.23	46.33	31.20

Figures 5 and 6, and Table 3 indicate that:

- the Delta Method, when compared with the ERA's proposed allocation:
  - allocates a higher ELCC to the wind farms in the south and east, and to the group of small wind and solar farms;
  - allocates a lower ELCC to the wind farms in the north, and to the group of biogas facilities;
  - allocates a higher ELCC to 1 of the 3 solar farms assessed individually and a lower ELCC to the other 2 solar farms; and
- the proposed Fleet ELCC, when allocated between Facilities under the Delta Method, results in some Candidate Facilities being assigned a higher Relevant Level than under the current RLM and other Facilities being assigned a lower Relevant Level than under the current method.

Figure 7 shows the First-In ELCC, Last-In ELCC and the resulting ELCC for each Candidate Facility or group of Facilities under the Delta Method.

Figure 7: First-In ELCC, Last-In ELCC and resulting ELCC for each Candidate Facility or group of Facilities under the Delta Method

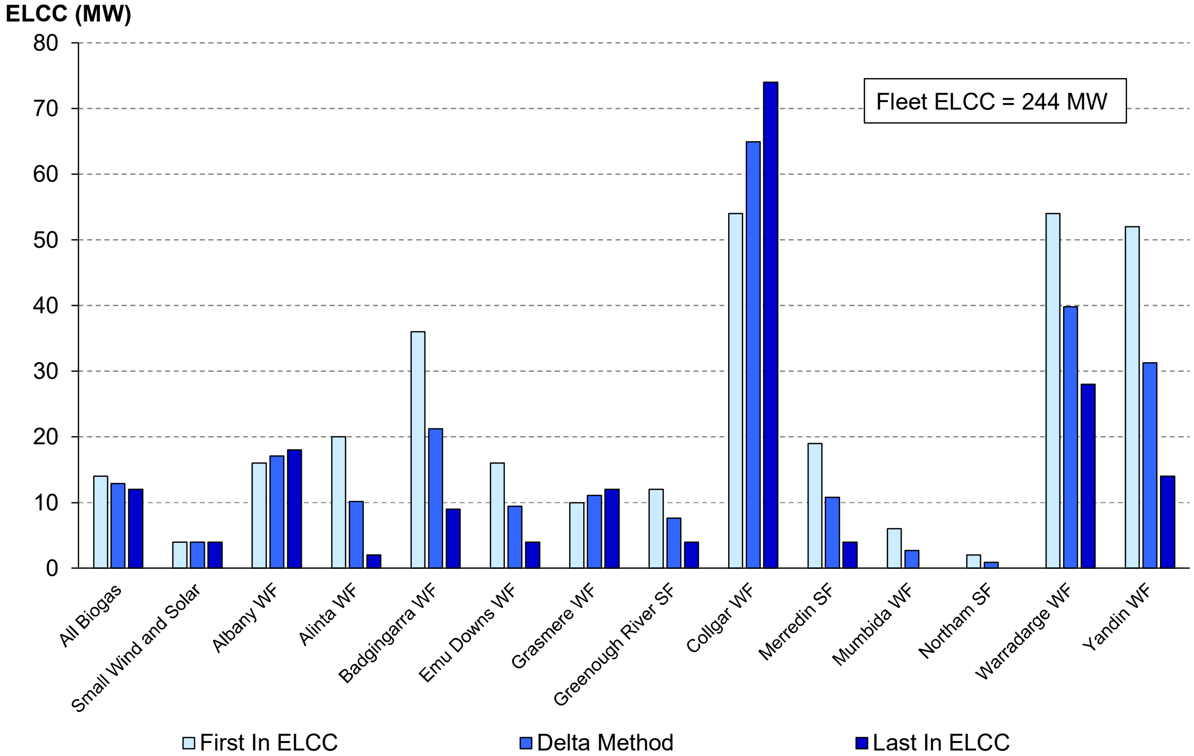

Figure 7 shows that wind farms in the north of the SWIS (where several wind farms are located) generally have a lower Last-In ELCC than First-In ELCC, while Collgar Wind Farm, which is the only wind farm in the east, and the wind farms in the south have a higher Last-In ELCC than First-IN ELCC.

The Rule Change Panel has undertaken further analysis of the Delta Method under different scenarios, as presented in section 6.2 of this report. As outlined in section 6.2, the Rule Change Panel considers that allocation of the RLM using the Delta Method reflects whether there is a need for more capacity of a certain type in a certain region (i.e. whether adding more capacity of a certain type in a certain region adds markedly to the Fleet ELCC or whether there is a saturation of that type of generation in that region). Therefore, allocation under the Delta Method will incentivise investments in capacity that complements the existing Fleet in terms of its ELCC.

As outlined in section 6.2 of this report, the Rule Change Panel considers that the ERA's proposed allocation based on Technology Groups and the performance of Candidate Facilities during the defined Trading Intervals gives too much weight to the performance during Trading Intervals that have no or little impact on the Fleet ELCC, while neglecting Trading Intervals that are driving the Fleet ELCC. As a result, the allocation under this approach does not send a signal that incentivises investments in capacity that complement the existing Fleet in terms of its ELCC.

The Rule Change Panel considers that it is inappropriate to allocate the Fleet ELCC based on the Facilities' performance during Trading Intervals that have little or no impact on the Fleet ELCC. The Rule Change Panel considers that it is important that the RLM incentivises investment in capacity that complements the existing Fleet regarding its ELCC and thus its contribution to system reliability.

The Rule Change Panel considers that the proposed increase in the granularity of the COPT from 1 MW to 0.1 MW, as discussed in section 6.1.9 of this report, would allow the assessment of the existing Intermittent Generators with a nameplate capacity below 10 MW. However, the Rule Change Panel acknowledges the possibility that a Candidate Facility with a nameplate capacity that cannot be assessed under the Delta Method may apply for certification in the future. The Rule Change Panel considers that the most practicable approach to address this issue is to assess small Facilities with a nameplate capacity below 10 MW as a group and to allocate the group ELCC based on their relative performance during selected Trading Intervals. The Rule Change Panel considers that the selected Trading Intervals should be the Trading Intervals that are most relevant for the Fleet ELCC.

Based on the observation of the change in the Fleet ELCC for different sets of high demand Trading Intervals, as outlined in section 6.1.4 of this report, the Rule Change Panel proposes to select the 50 Trading Intervals with the highest LOLP and the 50 Trading Intervals with the highest LOLP excluding the contribution of all other Candidate Facilities from the system demand.

The Rule Change Panel's draft decision is to adopt the Delta Method to allocate the Fleet Relevant Level between the individual Candidate Facilities and to:

- group Candidate Facilities with a nameplate capacity below 10 MW into the following groups, by technology:
    - biogas;
    - wind and solar farms and ESR; and

- allocate the ELCC of a Facility group between the Facilities in that group based on the Facilities' relative performance in the following Trading intervals:
    - the 50 Trading Intervals with the highest LOLP in the Reference Period; and
    - the 50 Trading Intervals with the highest LOLP in the Reference Period after excluding the contribution of all other Candidate Facilities from the system demand.

The Rule Change Panel asks stakeholders to provide feedback on:

- whether the proposed 10 MW threshold is appropriate; and
- whether it would be appropriate to allow AEMO to include any small Facilities with a nameplate capacity above the selected threshold in the small Facility groups if AEMO considers that the Facility may otherwise not be assessed appropriately due to rounding issues.

6.1.9 The Proposed COPT

The ERA proposes to account for the contribution of the non-Candidate Facilities to system reliability as follows:

- Scheduled Generators:
    - account for these Facilities in the COPT, based on the assumption that they are available with the same probability in each Trading Interval; and
    - assume that these Facilities will either be available as per their CRC or will suffer a full Forced Outage, with the probability of such an outage based on the average Forced Outage rate determined under clause 4.11.1(h) of the WEM Rules for the relevant Reserve Capacity Cycle and the two previous Reserve Capacity Cycles.[28]
- DSPs:
    - account for these Facilities in the COPT, based on the assumption that they are available with the same probability in each Trading Interval; and
    - assume that these Facilities will be available with a 100% probability, as per their CRC.
- ESR:
    - account for these Facilities by reducing the system demand in each Trading interval that is an Electric Storage Resource Obligation Interval; and
    - assume that these Facilities will either be available as per their CRC or will suffer a full Forced Outage applying an outage probability estimated by AEMO and letting a random number generator decide which Trading Intervals are affected by the Forced Outage.

The ERA proposes to determine the outage probability in the COPT from 0 MW to the sum of the CRCs of all Scheduled Generators and all DSPs in increments of 1 MW.

As outlined in issue 18 in Appendix A of this report, AEMO suggests that the WEM Rules should give it discretion to replace any of the three historical Forced Outage rates for a Scheduled Facility, where required.

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28 The Forced Outage rate of a Facility for a given Capacity Year determined under clause 4.11.1(h) of the WEM Rules is calculated as the Forced Outage Rate of the preceding 36 Trading Months.

Treatment of Scheduled Generators

The Rule Change Panel agrees with the following aspects of the ERA's proposed approach to account for Scheduled Generators' contribution to system reliability:

- accounting for Scheduled Generators in the COPT based on the assumption that they are available with the same probability in each Trading Interval; and
- assuming that a Scheduled Generator will either be available as per its CRC or suffer a full Forced Outage.

However, since the Forced Outage rate for a Facility for any Capacity Year is the average of the Facility's Forced Outages from the last three years, the ERA's proposal to determine the outage probability of a Scheduled Generator based on the average of the last three Forced Outage rates means that the outage probability will be based on the Facility's Forced Outages for the previous 5 years and will account for some years more often than for others. That is, it will account for:

- the Forced Outages from the previous year and from five years ago once;
- the Forced Outages two and four years ago twice; and
- the Forced Outages three years ago three times.

The Rule Change Panel considers that it is inappropriate to weigh the impact of Forced Outages from different historical years differently. The Rule Change Panel considers that the most appropriate Forced Outage rate would be the Forced Outage rate determined by AEMO for the current Reserve Capacity Cycle, because this rate is used to determine whether AEMO may reduce the Capacity Credits of a Facility for that Reserve Capacity Cycle, as per clause 4.11.1(h) of the WEM Rules.

The Rule Change Panel agrees with AEMO that it is appropriate to provide discretion to AEMO to adjust the outage probability of a Scheduled Generator for the COPT if AEMO considers that the Forced Outage rate for the relevant Capacity Year is not representative. However, the Rule Change Panel considers that implementing such a provision would require further consultation, including to determine under which conditions AEMO should have such discretion. The Rule Change Panel notes that, as shown in section 6.1.10 of this report, the impact of changes to the COPT from removing one or several Scheduled Generators is small. Therefore, the Rule Change Panel considers that implementing such a discretion should be assessed in the next RLM review.

Treatment of DSPs

The Rule Change Panel agrees with the following aspects of the ERA's proposed approach to account for DSPs' contribution to system reliability:

- accounting for DSPs in the COPT; and
- assuming that DSPs will have no Forced Outages.

However, the Rule Change Panel considers it is inappropriate to assume that DSPs are available in each Trading Interval. This is because the WEM Rules require DSPs to be available only between 8:00 AM and 8:00 PM on Business Days. The Rule Change Panel considers that it is credible that a Trading Interval with extreme system demand could fall and has fallen outside these periods.[29]

[29] For example, 3 Trading Intervals on 26 January 2012 (Australia Day) where amongst the 12 peak Trading Intervals used for the IRCR calculation in that year.

The Rule Change Panel acknowledges that the implementation of an individual COPT for each Trading Interval based on the availability requirements of the non-Candidate Facilities would increase the complexity of the RLM. The Rule Change Panel has consulted with AEMO and AEMO has confirmed that implementing multiple COPTs would increase the complexity of the methodology and would incur additional implementation costs. However, once the multiple COPTs are implemented in AEMO's system, AEMO does not expect there to be a material impact on the operation of the proposed RLM.

Treatment of ESRs

The Rule Change Panel agrees with the following aspects of the ERA's proposed approach to account for ESRs' contribution to system reliability:

- assuming that they will only be available during Trading Intervals that are Electric Storage Resource Obligation Intervals; and
- assuming that they will either be available as per their CRC or suffer a full Forced Outage.

However, the Rule Change Panel considers that it is inappropriate to apply the outage probability of ESRs randomly to the Electric Storage Resource Obligation Intervals in the Reference Period. The Rule Change Panel considers that the most practicable approach is to account for ESRs in the COPT, assuming the same outage probability for every Trading Interval that is an Electric Storage Resource Obligation Interval.

The Rule Change Panel considers that the capacity of ESR that are Non-Scheduled Facilities will be too small to be included in the COPT and should be addressed by reducing the assigned CRC from the system demand for Trading Intervals that are Electric Storage Resource Obligation Intervals.

Other COPT-Related Matters

The Rule Change Panel notes that the ERA's proposal to determine the outage probabilities in the COPT for 1 MW increments causes the requirement to group Candidate Facilities that have a nameplate capacity below 10 MW because their Relevant Level under the Rule Change Panel's proposed Delta Method is 0. The Rule Change Panel considers that this problem would be mitigated if the outage probabilities in the COPT were instead determined in 0.1 MW increments. The Rule Change Panel acknowledges that moving to 0.1 MW increments will increase the complexity of implementing the proposed RLM. However, the Rule Change Panel has consulted with AEMO, which has confirmed that the increased complexity would not materially affect the implementation and operation of the proposed RLM. The Rule Change Panel notes that, as outlined in section 6.1.8, it is possible that a Candidate Facility could register with a Nameplate Capacity that still requires grouping for the sake of the Delta Method.

Draft Decision Regarding COPTs

The Rule Change Panel's draft decision is to account for the contribution of the different types of non-Candidate Facilities to system reliability by:

- accounting for all non-Candidate Facilities in the COPT, except ESR that are Non-Scheduled Facilities;
- determining a separate COPT for each Trading Interval to account for the different availability requirements of the different types of non-Candidate Facilities;

- determining the outage probability from 0 MW to the sum of the CRC for all Facilities that have to be available in that Trading Interval in increments of 0.1 MW;
- making the following assumptions about the availability of Scheduled Generators:
  - they are available with the same probability in each Trading Interval;
  - they will either be available as per their CRC or suffer a full Forced Outage with the probability of such an outage based the Forced Outage rate determined under clause 4.11.1(h) of the WEM Rules for the relevant Reserve Capacity Cycle;
- making the following assumption about the availability of DSPs:
  - 100% probability that they will be available as per their CRC for Trading Intervals that fall between 8:00 AM and 8:00 PM on a Business Day; and
  - 0% probability that they will be available for Trading Intervals that don't fall between 8:00 AM and 8:00 PM on a Business Day;
- making the following assumption about the availability of ESR (that are Non-Scheduled Facilities):
  - they will either be available as per their CRC or suffer a full Forced Outage, with a probability estimated by AEMO in accordance with the WEM Procedure under clause 4.9.10 of the WEM Rules, for any Trading Interval in the Reference Period that would meet the criteria for an Electric Resource Obligation Interval published by AEMO for the Reserve Capacity Cycle under clause 4.11.3A(a); and
  - 0% probability that they will be available for any Trading Interval in the Reference Period that would not meet the criteria for an Electric Resource Obligation Interval published by AEMO for the Reserve Capacity Cycle under clause 4.11.3A(a); and
- accounting for ESR that are Non-Scheduled Facilities by reducing the assigned CRC from the system demand for Trading Intervals that are Electric Storage Resource Obligation Intervals.

Appendix B of this report provided a worked example of the formation of a COPT.

6.1.10 Uncertainty about the Expected Generation Fleet

The ERA's proposed RLM (and the amended RLM approved by the Rule Change Panel in this draft decision) requires the expected fleet of Intermittent and Scheduled Generators (**expected generator fleet**) as an input factor. The Rule Change Panel notes that the expected generator fleet may differ from the actual fleet that is eventually assigned Capacity Credits for the relevant Reserve Capacity Cycle for the following reasons:

- a Facility may receive fewer Capacity Credits than its CRC because its assigned NAQ is lower than its CRC;
- a Facility may not receive Capacity Credits because it does not receive any NAQ.
- a participant may decide not to apply for Capacity Credits for a Facility that received CRC (the Rule Change Panel considers that this risk would be highest for proposed new Facilities); and
- a participant may apply for fewer Capacity Credits for a Facility than the Facility's CRC.

The Rule Change Panel notes that:

- a change in the fleet of non-Candidate Facilities may affect the observed LOLE, which may affect the Relevant Level of the Fleet and of one or more Candidate Facilities; and
- a change in the Fleet is likely to affect the Relevant Level of the Fleet and the remaining Candidate Facilities.

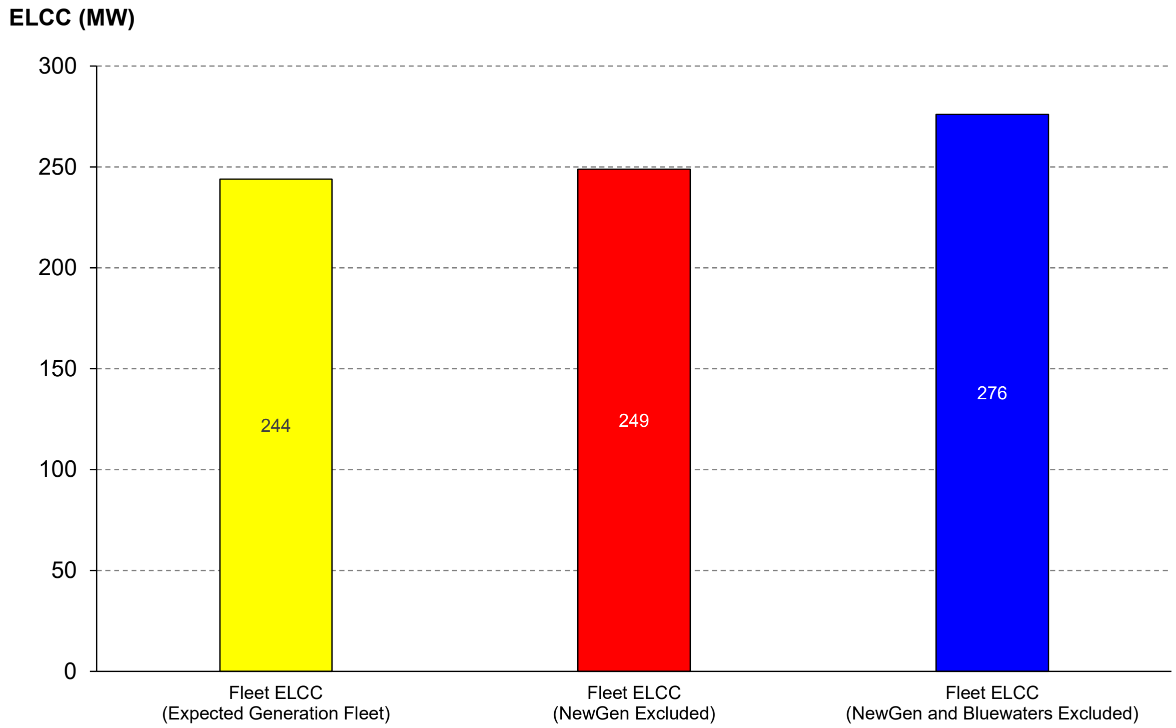
As outlined in section 5.3.5 of this report, Synergy raised concerns about the approach to include proposed Facilities as part of the Fleet.

To assess the impact of the expected fleet of non-Candidate Facilities being different from the actual fleet, the Rule Change Panel has calculated the Fleet RLM for the following scenarios using the Adjusted Model 2:

- **Scenario 1**: excluding Newgen Neerabup from the COPT;[30]
- **Scenario 2**: excluding Newgen Neerabup, Bluewaters 1 and Bluewaters 2 from the COPT;[30] and
- **Expected Generation Fleet Includes Battery**: including a Battery of 100 MW, to the COPT.[31]

The results of these calculations are summarised in Figures 8 and 9.

Figure 8: Comparison of the Fleet ELCCs for the expected generation fleet and for Scenarios 1 and 2



30 As a result the remaining Facilities in the COPT are scaled up, so the sum of all Capacity Credits accounted for in the COPT equals the Reserve Capacity Requirement. Note that this is an extreme scenario.

31 As a result the remaining Facilities in the COPT are scaled down, so the sum of all Capacity Credits accounted for in the COPT equals the Reserve Capacity Requirement.

Figure 9: Comparison of the Fleet ELCCs for the expected generation fleet with and without a battery

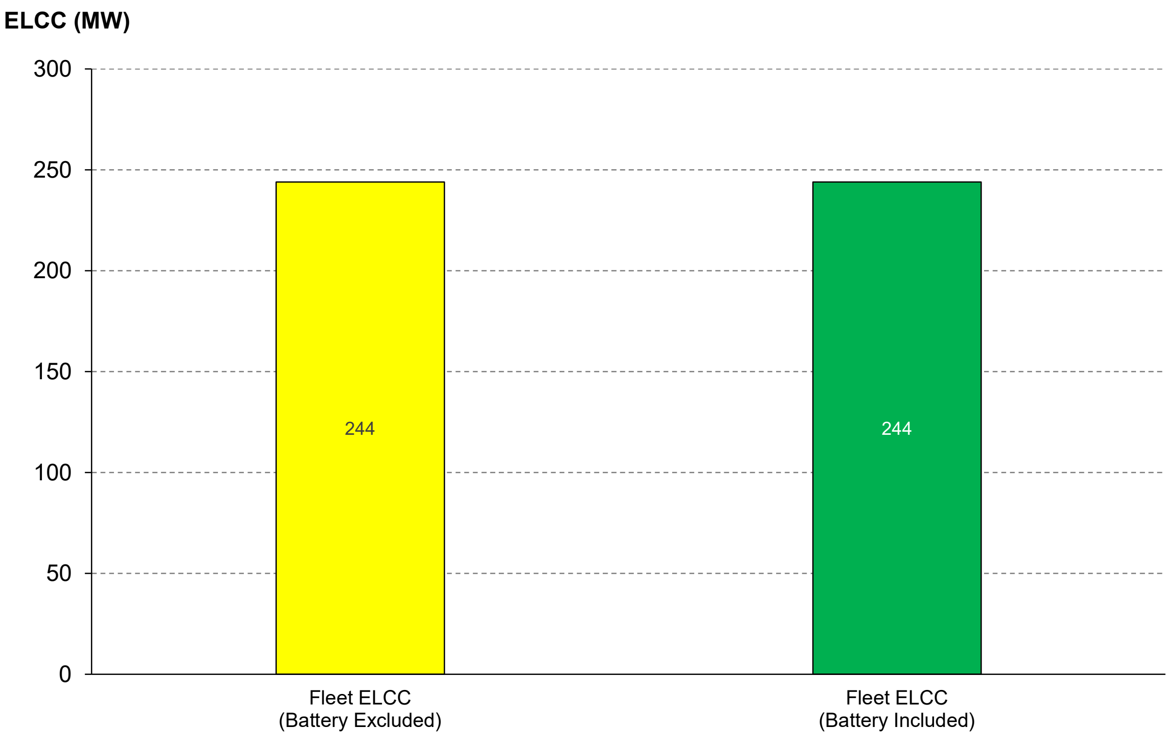


Figure 8 shows that changes to the fleet of non-Candidate Facilities may impact the Fleet ELCC but that changes relating to one Facility are likely to have little impact on the Fleet ELCC, and Figure 9 shows that the entry of a 100 MW battery into the SWIS is likely to have limited impact on the Fleet ELCC.

As observed in section 6.1.6 of this report, the Rule Change Panel notes that the proposed RLM has inherent volatility, caused by varying weather conditions from year to year. The impact of different weather conditions leaving and entering the Reference Period on Candidate Facilities is likely to be substantially bigger than the impact of changes to the fleet of Non-Candidate Facilities. However, the Panel considers that a simple way to mitigate this risk is to only include committed Facilities in the COPT.

To assess the impact of the expected Fleet of Candidate Facilities being different form the actual Fleet, the Rule Change Panel has calculated the Fleet RLM excluding different large wind farms from the Fleet, using the Adjusted Model 2. Specifically, the Rule Change Panel modelled the following scenarios:

- **Yandin Excluded Scenario**: excluding Yandin Wind Farm from the Candidate Facilities; and
- **Collgar Excluded Scenario**: excluding Collgar Wind Farm from the Fleet.

The results of these calculations are summarised in Figure 10.

Figure 10: Comparison of the Fleet Relevant Levels for the expected generation fleet compared with the Yandin Excluded Scenario and the Collgar Excluded Scenario

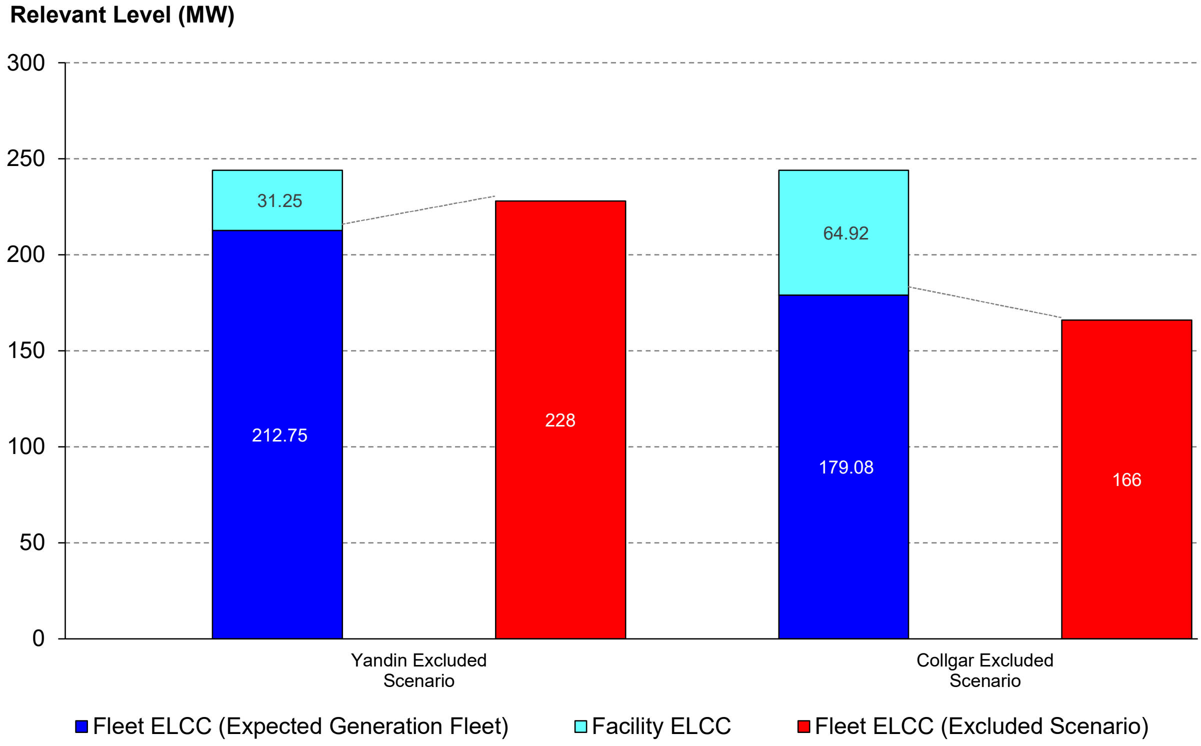


Figure 10 shows that the exclusion of a Candidate Facility from the Fleet can increase or decrease the Relevant Level of the remaining Candidate Facilities. As outlined in sections 6.1.8 and 6.2 of this report, the Rule Change Panel considers that the impact of adding or removing a Candidate Facility depends on whether it is located in a region that is saturated with other Facilities of the same type (such as wind farms in the north) or in a region that is not saturated with other Facilities of the same type (such as wind farms in the east).

Treatment of Proposed Candidate Facilities

The Rule Change Panel agrees with Synergy, that it is inappropriate to subject committed Candidate Facilities to the risk of being undervalued by the RLM because the RLM considers a proposed Candidate Facility that later does not form part of the actual Fleet. This risk will arise where exclusion of the proposed Facility increases the ELCC of the remaining Candidate Facilities (as in the Yandin Excluded Scenario).

The Rule Change Panel considers that it is also inappropriate to impose a risk on system reliability because the RLM considers a proposed Candidate Facility that later does not form part of the actual Fleet. This risk will arise where the exclusion of the proposed Facility decreases the ELCC of the remaining Candidate Facilities (as in the Collgar Excluded Scenario).

The Rule Change Panel notes that the WEM Rules require that proposed Candidate Facilities are assessed by the RLM and changing this requirement is outside the scope of this Rule Change Proposal.

The Rule Change Panel considers that the most appropriate approach to address these risks is to first determine the Relevant Level for the committed Candidate Facilities and then to consider proposed Candidate Facilities in a separate round of RLM calculations.

The Rule Change Panel's draft decision is to implement two separate rounds for the determination of the Relevant Levels of committed and proposed Facilities as follows:

- Determine the Relevant Levels of the committed Candidate Facilities first by excluding the proposed Facilities form the Fleet;
- Determine the Relevant Levels of the proposed Facilities as follows:
  - determine the ELCC of the Fleet (including committed and proposed Candidate Facilities) and allocate the difference between the Fleet ELCC with the proposed Facilities and the Fleet ELCC without the proposed Facilities to the fleet of proposed Facilities; and
  - allocate the ELCC of the fleet of proposed Facilities to the individual proposed Facilities based on the Delta Method, assuming the committed Facilities had already reduced the system demand for the First-In ELCCs and the Last-In ELCCs.

6.1.11 Treatment of Early and Conditional CRC

Early CRC

Section 4.28C allows Market Participants to apply for Early CRC for a Facility for a future Reserve Capacity Cycle, subject to various conditions.

The Rule Change Panel notes that clause 99.11 of the T2&3 Amending Rules will replace section 4.28C in its entirety. However, the Minister has not yet published a commencement date for clause 99.11, so the timing of the replacement relative to the progression of this Rule Change Proposal is uncertain. The Rule Change Panel notes that the Rule Change Proposal was submitted before the Gazettal of the T2&3 Amending Rules.

Under the WEM Rules that will be in force on 1 July 2021(assuming only confirmed commencements):

- Early CRC is restricted to new Facilities that are generating systems and deemed by AEMO to be committed;
- an application for Early CRC:
  - may be submitted to AEMO at any time before 1 January of Year 1 of the Reserve Capacity Cycle to which the application relates; and
  - must be processed by AEMO within 90 days of receiving the application;
- if AEMO assigns Early CRC to a Facility then:
  - the Market Participant must provide Reserve Capacity Security for the Facility within 30 Business Days;
  - once the Reserve Capacity Security is provided, AEMO must assign the Facility a quantity of Capacity Credits for the future Reserve Capacity Cycle equal to its Early CRC; and
  - the Market Participant is not required to make any further application for CRC or Capacity Credits in respect of that future Reserve Capacity Cycle.

Under the new section 4.28D specified in the T2&3 Amending Rules:

- Early CRC is restricted to new Facilities that are Energy Producing Systems (which includes generating systems and ESRs) and deemed by AEMO to be committed, where AEMO is satisfied that:
  - the construction of the Facility cannot be achieved within the Reserve Capacity Cycle for which Capacity Credits are being sought for the Facility; and
  - the Commissioning Tests for the Facility cannot be achieved before the commencement of the Capacity Year for which Capacity Credits are being sought for the Facility;
- an application for Early CRC:
  - may be submitted to AEMO at any time, but not earlier than two years before 1 January of Year 1 of the Reserve Capacity Cycle to which the application relates; and
  - must (if submitted before the deadline for responses to the Request for Expressions of Interest for a Reserve Capacity Cycle) be processed by AEMO at the time AEMO next processes applications for CRC in accordance with section 4.11; and
- if AEMO assigns Early CRC to a Facility then:
  - AEMO will assign an Indicative NAQ to the Facility (rather than Capacity Credits); and
  - the Market Participant is required to provide Reserve Capacity Security for the Facility within 30 Business Days of being notified of its Indicative NAQ.

EPWA has indicated to the Rule Change Panel that it is considering further changes to the WEM Rules to:

- allow Early CRC applications for upgrades of existing Facilities;
- restrict Early CRC applications for Intermittent Generating Systems to those that are Network Augmentation Funding Facilities; and
- clarify that, because the Market Participant is no longer automatically assigned Capacity Credits for any Early CRC assigned to its Facility, it must still submit an application for CRC in Year 1 of the relevant Reserve Capacity Cycle (and may receive a level of CRC that differs from its Early CRC).

The ERA proposes to restrict Early CRC for Facilities that would be certified using the RLM to Facilities that would not be part of a Facility Group with an interaction index of one, which would make wind and solar Intermittent Generating Systems ineligible for Early CRC. However, EPWA has indicated in discussions with RCP Support that this would be inconsistent with the Minister's intent to allow the Early CRC mechanism to be used for Network Augmentation Funding Facilities that are dependent on the completion of large-scale network augmentation processes, which may include wind and solar Intermittent Generating Systems.

Based on EPWA's advice, the Rule Change Panel does not consider it appropriate to prohibit applications for Early CRC for wind and solar Facilities. However, the Rule Change Panel agrees with the ERA that including such Facilities in the Relevant Level calculation for the current Reserve Capacity Cycle would be distortionary, because the Fleet ELCC and the Relevant Levels of other Candidate Facilities would be affected by the incorrect assumption that the Early CRC Facilities would be operating in the relevant Capacity Year.

The Rule Change Panel considers that the most practical and appropriate approach is to process applications for Early CRC in an additional, separate step of the RLM process, after the assessment of committed and proposed Facilities for the current Reserve Capacity Cycles. This will allow Relevant Levels to be calculated for Early CRC Facilities without affecting the Relevant Levels used for certification for the current Reserve Capacity Cycle.

Conditional CRC

The ERA also proposed that, if a Market Participant applies for Conditional CRC for a Facility (or part of a Facility) that is assessed under the RLM:

- AEMO must determine the Relevant Level for this Facility by applying the RLM based on the input data used for the most recent Reserve Capacity Cycle and the relevant performance data from the Facility; and
- in this application of the RLM, AEMO may have regard to its expectations about the resource mix and demand for the Capacity Year that the Conditional Reserve Capacity relates to.

As previously noted, the ERA submitted this Rule Change Proposal before the Gazettal of the T2&3 Amending Rules. The T2&3 Amending Rules include several changes to the Conditional CRC provisions in section 4.9 that commenced on 1 February 2021. The Minister's changes include the addition of new clause 4.9.7A, which requires AEMO to process an application for Conditional CRC at the time it next processes applications for CRC for a Reserve Capacity Cycle, in accordance with section 4.11.

AEMO noted in its first period submission the discrepancy between the ERA's proposed amendments and the new clause 4.9.7A.

The Rule Change Panel considers that the most practical and appropriate approach is to process applications for Conditional CRC in an additional separate step of the annual RLM process, after the assessment of Early CRC Candidate Facilities. This will allow Relevant Levels to be calculated for Conditional CRC Facilities without affecting the Relevant Levels used for certification for the current Reserve Capacity Cycle or the assignment of Early CRC.[32]

The ERA also proposed changes to clause 4.9.5 to make Conditional CRC conditional on whether AEMO's subsequent assessment of the CRC of the Facility in Year 1 of the future Reserve Capacity Cycle is equal to the Conditional CRC.

The Rule Change Panel considers that clause 4.9.5(c) already indicates that the requirement for AEMO to confirm previously assigned Conditional CRC without reassessment applies only to non-intermittent Facilities. Where an application for CRC is submitted for an Intermittent Generating System previously assigned Conditional CRC, the CRC for the current Reserve Capacity Cycle is to be recalculated using the RLM.

The Rule Change Panel does not consider there is any need to change the existing arrangements, but considers that arrangements for Conditional CRC Facilities that are certified using the Relevant Level Method should be made more explicit.

32 The Rule Change Panel considers that Early CRC applications should be considered before Conditional CRC applications because the implications of Early CRC (e.g. in terms of the subsequent assignment of Indicative NAQ) are more material than the implications of Conditional CRC (which is indicative only for Facilities that are certified using the RLM).

The Draft Decision

The Rule Change Panel's draft decision is to assess the different Facility groups as follows, and in the order listed:

(1) Committed Facilities applying for CRC for the current Reserve Capacity Cycle (**Committed Facilities**):

  (a) determine the Fleet ELCC for the fleet of Committed Facilities; and

  (b) allocate the Fleet ELCC between the relevant Facilities using the Delta Method.

(2) Proposed Facilities applying for CRC for the current Reserve Capacity Cycle (**Proposed Facilities**):

  (a) determine the fleet ELCC for all Committed Facilities assessed under step (1) and all Proposed Facilities;

  (b) determine the difference between the fleet values calculated under steps (1) and (2)(a); and

  (c) allocate the value determined under step (2)(b) between the Proposed Facilities using the Delta Method.

(3) Facilities applying for Early CRC:

  (a) determine the fleet ELCC for all Facilities assessed under steps (1) and (2) and for all Facilities applying for Early CRC;

  (b) determine the difference between the fleet values calculated under steps (2) and (3)(a); and

  (c) allocate the value determined under step (3)(b) between the Facilities applying for Early CRC using the Delta Method.

(4) Facilities applying for Conditional CRC:

  (a) determine the fleet ELCC for all Facilities assessed under steps (1), (2) and (3) and for all Facilities applying for Conditional CRC;

  (b) determine the difference between the fleet values calculated under steps (3) and (4)(a); and

  (c) allocate the value determined under step (4)(b) between the relevant Facilities applying for Conditional CRC using the Delta Method.

The Rule Change Panel acknowledges that this approach may undervalue or overvalue the contribution of Facilities that are assessed in steps (2) to (4). However, the Rule Change Panel considers that this is acceptable because any other approach may negatively affect system reliability.

As outlined in section 6.1.8 of this report, the Rule Change Panel proposes a different process for small Candidate Facilities, which may be too small to produce meaningful Relevant Levels under the standard process. Based on this approach, the Rule Change Panel proposes to assign Relevant Level for small Non-Scheduled proposed, Early CRC or Conditional CRC Facilities based on the calculation used to assign Relevant Levels to committed Non-Scheduled Facilities of a similar type. This approach is specified in section 7 of this report.

The Rule Change Panel does not consider there is any need to change the existing arrangements, but proposes some additional changes to clause 4.9.5 to make the arrangements for Conditional CRC Facilities that are certified using the Relevant Level Method more explicit.

6.1.12 Timeframe for the RLM

The ERA proposed no changes to the timeframes for the CRC assessment or for any other Reserve Capacity Cycle events.

As outlined in section 5.3.7 of this report, AEMO raised concerns that it would need at least 7 to 9 Business Days longer for the assessment of CRC using the new RLM.

The Rule Change Panel agrees with AEMO that the RLM proposed by the ERA (and the RLM as amended under the Rule Change Panel's draft decision) is more complex and will likely increase the time that AEMO needs for the CRC assessment.

The Rule Change Panel notes that the Minister for Energy has recently amended the Reserve Capacity Cycle timeframes as part of the ETS. Therefore, the Rule Change Panel has consulted with EPWA about the intent of the timeframes. EPWA noted that the current deadline for the close of applications for CRC was chosen to allow stakeholders sufficient time to consider the information published in the ESOO before the close of the application window.

The Rule Change Panel considers that it would be inappropriate to shorten the timeline established by the ETS under this Rule Change Proposal.

The Rule Change Panel will engage with AEMO during the second submission period to explore the following alternative solutions to provide AEMO with more time to process the RLM:

- moving the deadline for notifying applicants of their CRC assignments to a later date, and adjusting the timeframes for subsequent events, up to and including the publication of CRC and Capacity Credit assignments, accordingly;
- processing the new RLM in the given timeframe, which may require additional resourcing; and
- moving the date for the publication of the CRC and the related timeframes of the RCM to a later date.

The Rule Change Panel asks stakeholders to provide feedback on what they consider to be the latest acceptable time for the publication of CRC and Capacity Credit assignments, and the reason for their opinions.

6.1.13 Publication of Information Relevant to the RLM

The ERA proposes to require the publication of all input data that would enable stakeholders to determine the Relevant Levels for their Facilities.

In their first period submissions, Alinta Energy and Synergy supported the improved transparency of the ERA's proposed RLM.

The Rule Change Panel agrees with the ERA that stakeholders should ideally be able to estimate the future Relevant Levels of their Facilities. The Rule Change Panel considers that such transparency would best enable the locational investment signals of the proposed RLM in this draft decision.

The Rule Change Panel notes that, to make any assessment of a facility's Relevant Level under the proposed draft decision, stakeholders would require the following information:

- the COPTs used to determine the Relevant Levels;
- historical system demand, including the relevant information about DSP dispatch, Interruptible Load dispatch and involuntary load shedding;
- the estimated historical and future levels of behind-the-meter PV capacity that AEMO uses for the DER adjustment of the system demand;
- the historical information about solar irradiance that AEMO uses for the DER adjustment of the system demand profile; and
- the historical output (actual or based on independent expert reports) of all other Facilities assessed under the RLM.

The Rule Change Panel notes that historical output data is currently published for each Facility after its full operational date in the form of SCADA data. However, the Rule Change Panel acknowledges that some stakeholders may consider the following historical output for Facilities to be confidential:

- the historical output for a Facility before its full operational date provided through independent expert reports; and
- the output estimated by AEMO for Trading Intervals where a Facility's output has been reduced and AEMO is required to provide an estimate.

The Rule Change Panel considers that, since this data is historical, the benefit from the increased transparency that would be achieved by publishing this information would outweigh any perceived detriment from such a publication.

The Rule Change Panel notes that AEMO currently bases its assessment of the historical contribution of behind-the-meter PV on historical irradiance data that it purchases from SolCast. Therefore, the Rule Change Panel considers that it would not be appropriate to require this information to be published, and notes that stakeholders can purchase this information themselves.

The Rule Change Panel's draft decision is to require the publication of the data listed above, with the exception of the solar irradiance data. AEMO would also be required to publish a summary of key RLM process results for each Reserve Capacity Cycle.

The Rule Change Panel asks stakeholders whether they have any concerns with the publication of the outlined information, and if so, to provide any reasons for such concerns.

6.2 Implications of the Draft Decision

6.2.1 Use of the Proposed ELCC Measure

The ELCC is determined as the firm capacity that could replace the assessed Intermittent Generators, without changing the system's LOLE.[33]

The ELCC can be:

- Based on an initial specific target LOLE, in which case the input system demand is scaled (increased or decreased by flat load) until the observed LOLE equals the target

33 Firm capacity is a theoretical concept of capacity that is always available to the stated amount without being subject to outages or maintenance.

LOLE. As outlined in section 6.1.6 of this report, the Rule Change Panel considers that this approach is inappropriate for the WEM because it is not consistent with the Planning Criterion.

- Based on the observed LOLE, in which case the input system demand is not scaled to reach a specific target but instead the observed LOLE sets the target. The Rule Change Panel's draft decision is to adopt this approach and to amend the COPT so that the capacity from Non-Candidate facilities equals the Reserve Capacity Requirement.

Setting the target LOLE at the observed LOLE effectively means setting a different target LOLE for different Reference Periods based on the amount of Trading Intervals in the Reference Period with high system stress. With the current fleet of Non-Candidate Facilities in the WEM (mainly Scheduled Generators that must be available in every Trading Interval, except for Planned Outages) the times of highest system stress (without accounting for the Candidate Facilities) will most likely be the Trading Intervals with the highest system demand.[34]

The Rule Change Panel's draft decision is to assess the Candidate Facilities on a fleet basis. The Fleet ELCC for any given period will be driven by the performance of the Fleet during the Trading Intervals with the highest system stress (i.e. the highest LOLP). The Trading Intervals with the highest system stress that coincide with the worst performance of the Fleet will limit the Fleet ELCC.

Some of the key dynamics captured by the ELCC are:

- There are diminishing marginal returns to system reliability from a specific type of Facility. That is, continuing to add more of the same type of Facility to the same region in an electricity system will produce lower and lower increases in the system's ELCC. Installing multiple PV Facilities provides an intuitive illustration – continually adding PV in a region will eventually shift the periods of high system stress to Trading Intervals where PV is less effective, at which point adding more PV will have less impact on the system LOLE.
- Combining resources with complementary characteristics can lead to a total ELCC that is greater than the sum of its parts – this is referred to as the 'diversity benefit'. There are many combinations of resources that will produce such an effect – PV and ESRs provide an intuitive illustration – solar PV provides a source of energy for charging the ESRs and acts to sharpen the shape of the net peak demand, thereby reducing the length of the period during which ESR must discharge to reduce the peak.

6.2.2 Impact of the Proposed ELCC Measure

The dynamics of the ELCC mean that, if a new Candidate Facility is added to the Fleet:

- the Fleet ELCC:
    - will increase less if the new Facility's output is similar to the output of the Fleet (that is, if it does not perform well during Trading Intervals with high system stress during which the Fleet does not perform well); and

34 For ease of modelling, the model assumes that all Facilities in the COPT have to be available in all Trading Intervals. This does not reflect the Rule Change Panel's draft decision to implement multiple COPTs to account for the different availability obligations of the different non-Candidate Facilities.

- will increase more if the new Facility's output complements the output of the Fleet (that is, if it performs well during Trading Intervals with high system stress during which the Fleet does not perform well).

- the ELCC of an existing Candidate Facility:
  - could decrease if the new Facility's output is similar to the existing Facility's output; and
  - is likely to increase if the new Facility's output complements the existing Facility's output.

To assess the impact of adding different Candidate Facilities on the Fleet ELCC and on the ELCCs of the other Candidate Facilities, the Rule Change Panel has calculated the Fleet ELCC assuming the entrance of additional large wind farms, using the Adjusted Model 2. Specifically, the Rule Change Panel modelled the following scenarios:

- **Additional Eastern Wind Farm Scenario**: adding an additional wind farm in the eastern region, which was modelled as a Facility with the same historical output as Collgar Wind Farm (nameplate capacity 206 MW) in each Trading Interval of the Reference Period; and
- **Additional Northern Wind Farm Scenario**: adding an additional wind farm in the northern region, which was modelled as a Facility with the same historical output as Yandin Wind Farm (nameplate capacity 214 MW) in each Trading Interval of the Reference Period.

The results of these calculations are summarised in Figures 11 to 13.

Figure 11: Comparison of the Fleet ELCCs for the expected generation fleet, and the Additional Eastern Wind Farm and Additional Northern Wind Farm Scenarios

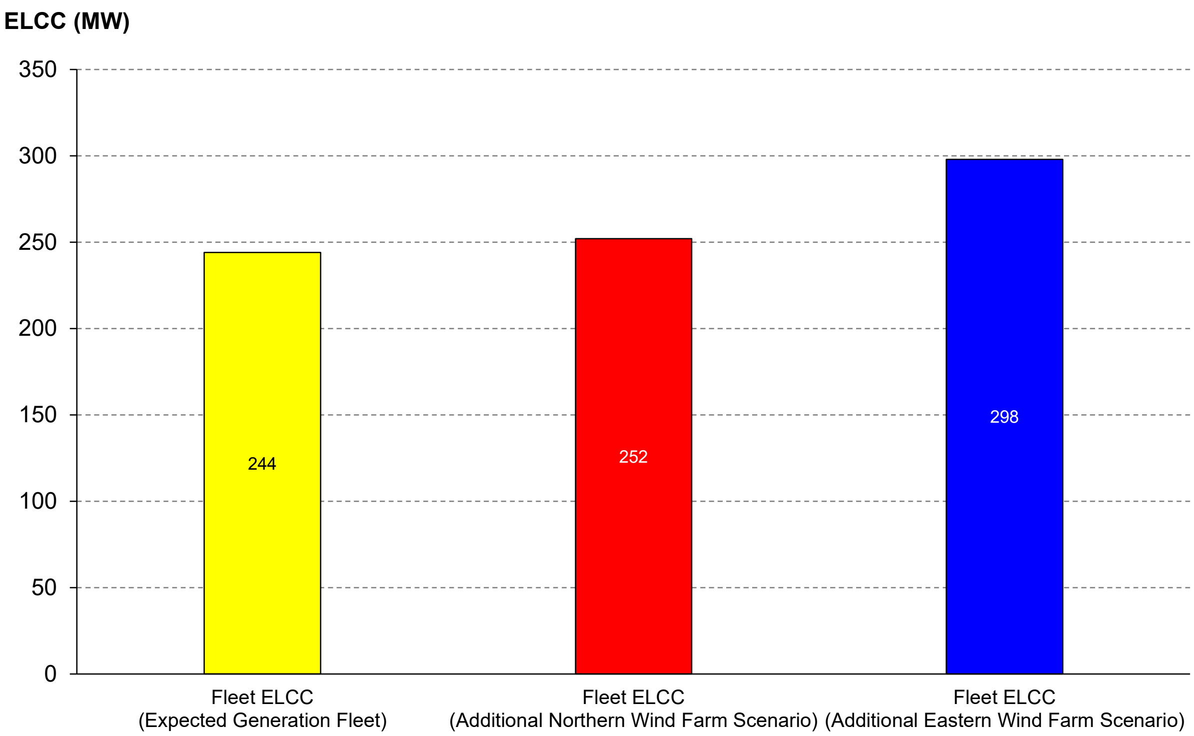
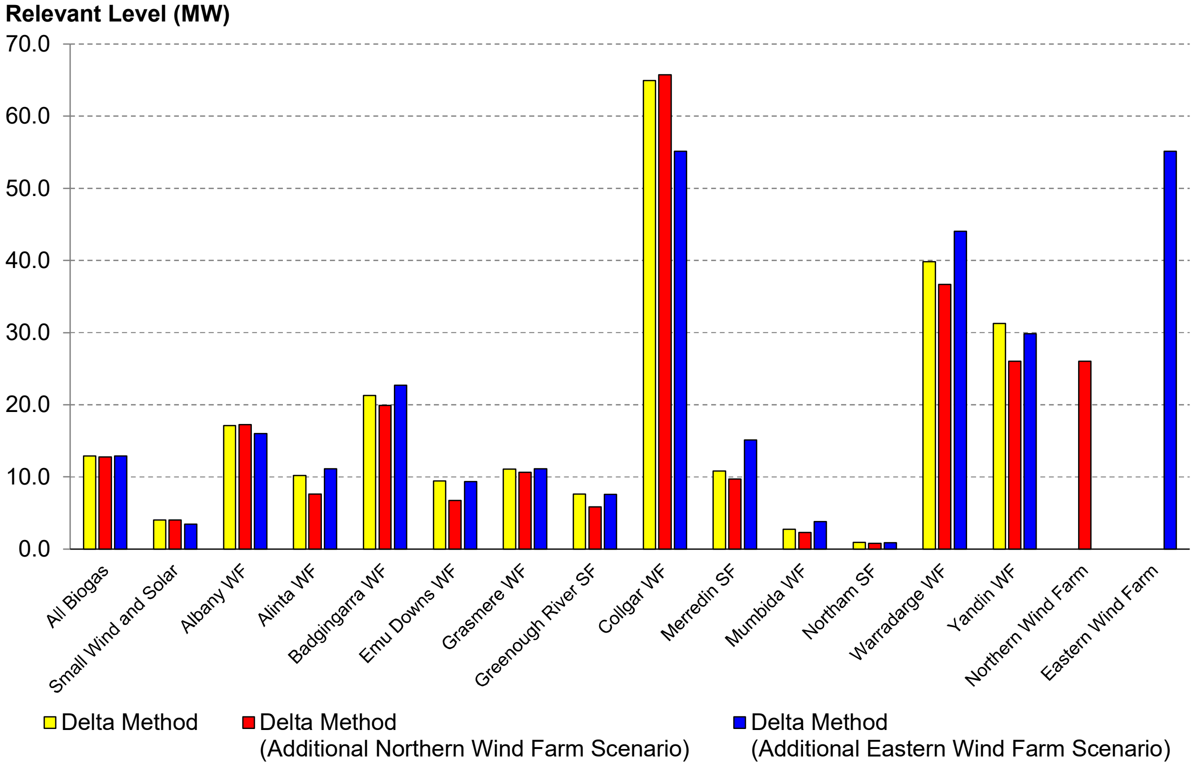


Figure 11 shows that the Fleet ELCC increases by 54 MW in the Additional Eastern Wind Farm Scenario and by 8 MW in the Additional Northern Wind Farm Scenario. The Rule Change Panel considers that this indicates that the output of an additional Facility in the east may complement the output of the Fleet better than the output an additional wind farm in the north because there appears to be saturation of wind farms in the north.[35] The Rule Change Panel notes that this observation is based on the observed Reference Period and may be different for a different Reference Period and would change over time as the mix of Candidate Facilities in the Fleet changes.

Figure 12: The Relevant Levels allocated to Candidate Facilities for the expected generation fleet, compared to the Additional Eastern Wind Farm and Additional Northern Wind Farm Scenarios (large Facilities and groups of small Facilities)



35 See Figure 6, which shows that wind farms in the north currently generally have a lower Last-In ELCC than First-In ELCC; whereas wind farms in the south and east generally have a higher Last-In ELCC than First-In ELCC. This indicates that the north may already be saturated with wind farms (i.e. adding wind farms in the north will currently not markedly add to the Fleet ELCC).

Figure 13: The Relevant Levels allocated to Candidate Facilities for the expected generation fleet, compared to the Additional Eastern Wind Farm and Additional Northern Wind Farm Scenarios (biogas and small wind and solar Facilities)

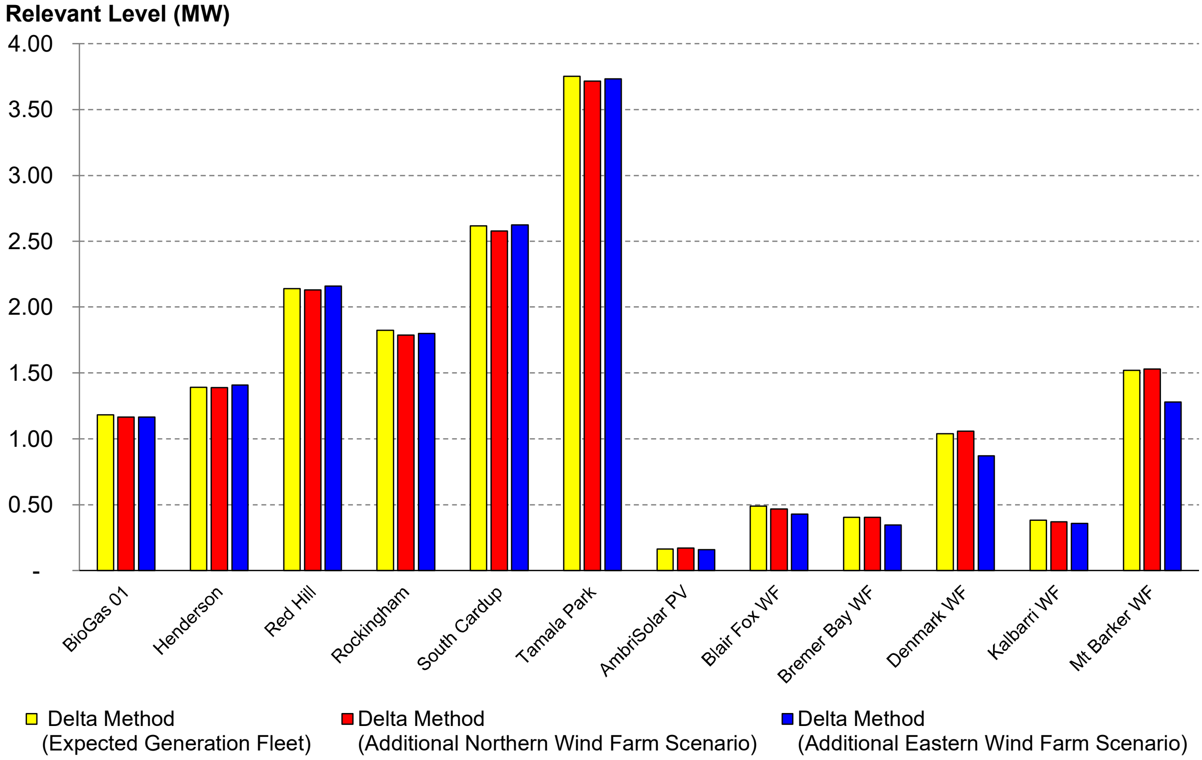


Figure 12 shows that:

- If a new wind farm resembling Collgar Wind Farm was added to the Fleet:
  - its Relevant Level would be 55 MW (compared to 206 MW nameplate capacity);
  - the Relevant Levels of most other Candidate Facilities would increase; and
  - the Relevant Level of Albany and Grasmere Wind Farms would decrease slightly.
- If a new wind farm resembling Yandin Wind Farm was added to the Fleet:
  - its Relevant Level would be 26 MW (compared to 214 MW nameplate capacity);
  - the Relevant Levels of most other Candidate Facilities would decrease slightly or stay the same; and
  - The Relevant Level of Badgingarra Wind Farm would increase slightly.

Figure 13 indicates that neither the addition of a wind farm resembling Collgar nor the addition of a wind farm resembling Yandin would markedly affect the allocation of the ELCC of the group of biogas Facilities or the group of small wind and solar farms.

6.2.3 Impact of the Approach to Allocate the Relevant Level

To consider the impact of the method used to allocate the Relevant Levels on the market, the Rule Change Panel has compared the allocation of the Relevant Levels under the Additional Eastern Wind Farm and Additional Northern Wind Farm Scenarios, using the ERA's proposed allocation method vs. the Delta Method using Adjusted Model 2. The results of this analysis is presented in Figures 14 and 15.

Figure 14: Comparison of the Relevant Levels allocated to Candidate Facilities under the Additional Eastern Wind Farm and Additional Northern Wind Farm Scenarios, using the ERA's proposed allocation methodology vs. the Delta Method (large Facilities and groups of small Facilities)

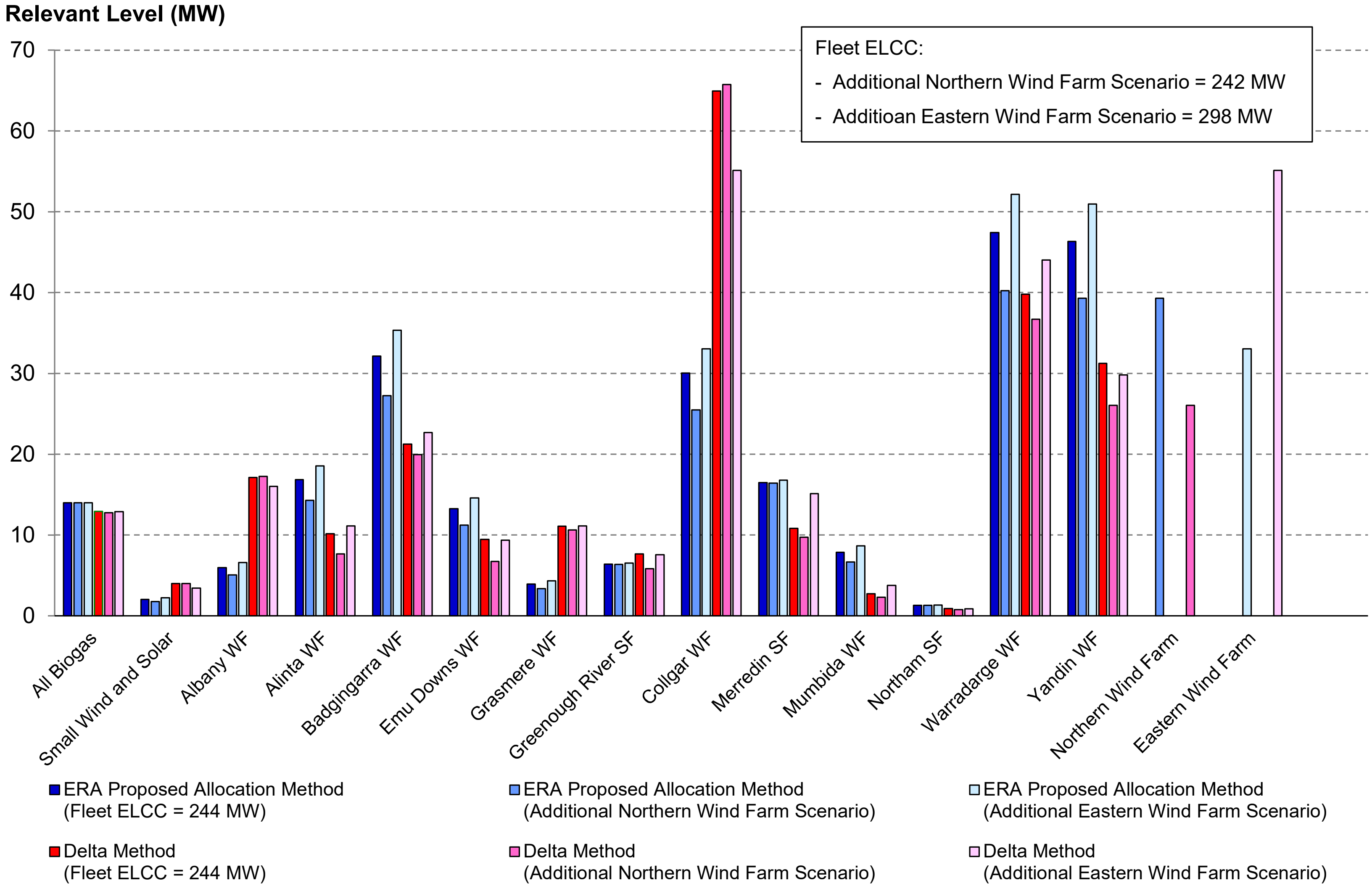
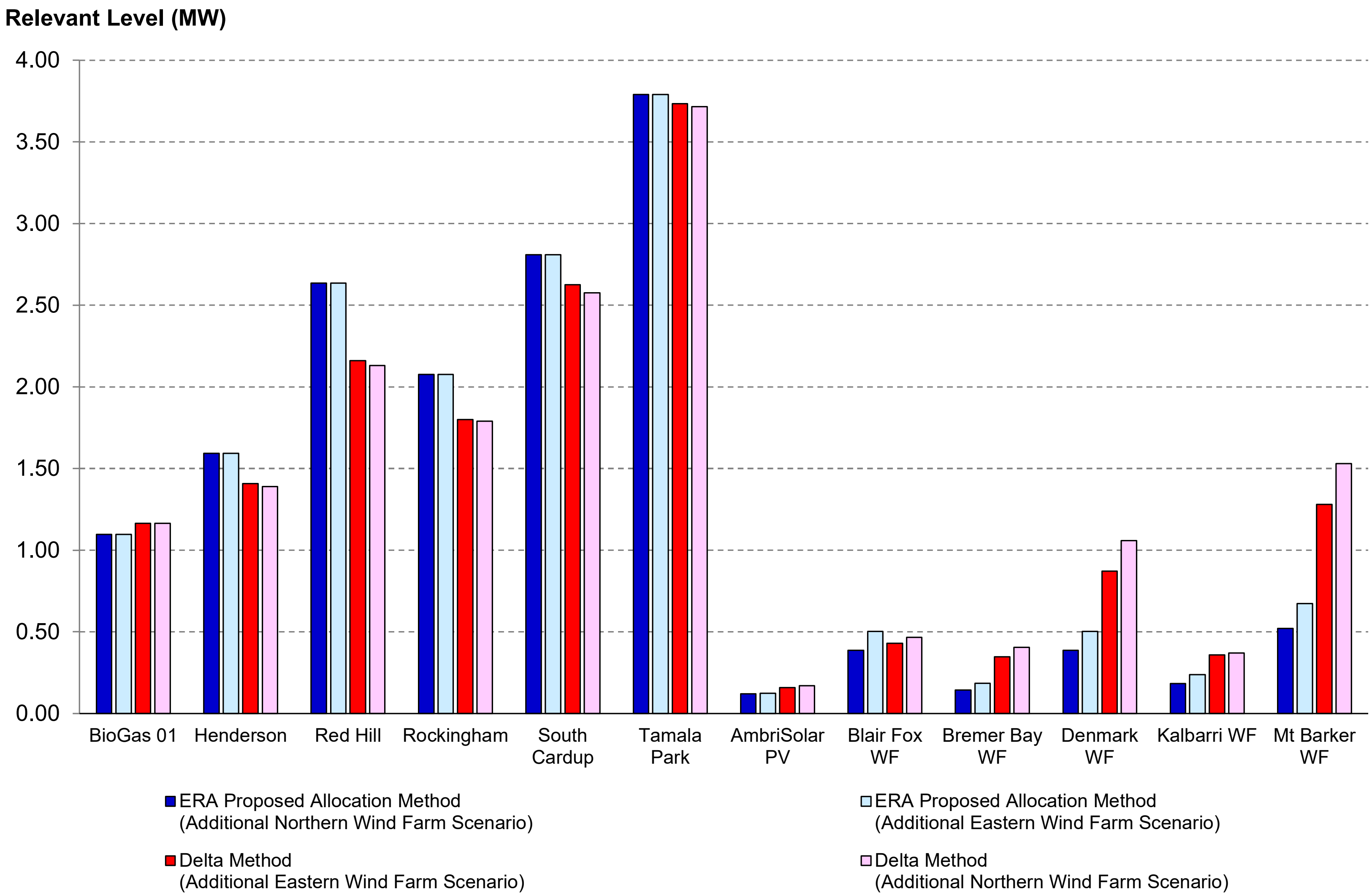


Figure 15: Comparison of the Relevant Levels allocated to individual Candidate Facilities under the Additional Eastern Wind Farm and Additional Northern Wind Farm Scenarios, using the ERA's proposed allocation methodology vs. the Delta Method (biogas and small wind and solar Facilities)



Figures 14 and 15 show that:

- If a new wind farm resembling Collgar Wind Farm was added to the Fleet:
    - its Relevant Level would be around 33 MW under the ERA's allocation method, which is 22 MW less than under the Delta Method;
    - the Relevant Levels of most other Candidate Facilities would increase or stay the same under the ERA's allocation method, compared to their Relevant Levels under the original Fleet; and
    - as outlined in section 6.2.1, under the Delta Method, the Relevant Level would increase for some Candidate Facilities and decrease for others, compared to their Relevant Levels under the original Fleet.
- If a new wind farm resembling Yandin Wind Farm was added to the Fleet:
    - its Relevant Level would be around 39 MW under the ERA's allocation method, which is 13 MW higher than under the Delta Method;
    - the Relevant Levels of all other Candidate Facilities would decrease or stay the same under the ERA's allocation method compared to their Relevant Levels under the original Fleet; and
    - as outlined in section 6.2.1, under the Delta Method, the Relevant Level would increase for some Candidate Facilities and decrease for others, compared to their Relevant Levels under the original Fleet.

The Rule Change Panel considers that this reflects its conclusion as outlined in section 6.1.8 of this report that the ERA's proposed method to allocate the Fleet Relevant Level between the Candidate Facilities may mute the signal to build additional Intermittent Generators that complement the existing Fleet.

6.3 Additional Changes to the Proposed Amending Rules

Following the first submission period, the Rule Change Panel has made some additional changes to the proposed Amending Rules to reflect the draft decision outlined in section 6.1 of this report. These additional changes are provided in detail in Appendix C of this report. The Rule Change Panel notes that, because the RLM proposed in the Draft Rule Change Report is substantively different from the RLM proposed in the Rule Change Proposal, the additional changes to Appendix 9 are not provided in mark-up and Appendix 9 is replaced in its entirety.

6.4 Wholesale Market Objectives

The Rule Change Panel considers that the WEM Rules, as a whole, if amended as proposed in section 7 of this report, will better achieve Wholesale Market Objectives (a), (b), (c) and (d); and are consistent with Wholesale Market Objective (e).

The Rule Change Panel's assessment is presented below.

Improved Estimation of the Capacity Value of the Fleet of Intermittent Generators

The current RLM contains several sources of error that can lead to under- or over-estimating the capacity value of the fleet of Intermittent Generators.

If the fleet's capacity value is over-estimated, then AEMO will assign too many Capacity Credits to Intermittent Generators. This can:

- create a risk to Power System Reliability, if the fleet fails to perform as expected during Trading Intervals with high system stress;
- inappropriately reduce the Reserve Capacity Price, which may discourage the efficient entry of new capacity (including capacity capable of providing other services to the market); and
- discriminate in favour of Intermittent Generators compared with non-Intermittent Facilities.

If the fleet's capacity value is under-estimated, then AEMO may assign too few Capacity Credits to Intermittent Generators. This can:

- inappropriately increase the Reserve Capacity Price;
- encourage the inefficient procurement of new capacity; and
- discriminate against Intermittent Generators compared with Non-Intermittent Facilities.

If it is sustained, the over- or under-estimation can also affect the long term cost of electricity, through the effects of inefficient investment decisions and the costs of capacity shortfalls and unserved energy.

The Rule Change Panel considers that the proposed RLM, as amended in this Draft Rule Change Report will better achieve Wholesale Market Objectives (a), (b), (c) and (d) by removing the errors that have been identified in the current RLM and therefore reducing the likelihood of over- or under-estimation of capacity value.

Improved Allocation of the Fleet's Capacity Value to Individual Intermittent Generators

The method of allocating the fleet value to individual facilities proposed in this Draft Rule Change Report will avoid discrimination against particular energy options and technologies by:

- more accurately identifying the Trading Intervals with high system stress, when the performance of Intermittent Generators is more critical;
- more accurately reflecting the contribution of individual Intermittent Generators to the Interaction Effect;
- not assuming that the performance of facilities of a common technology type is positively correlated; and
- treating new and existing facilities more consistently than the current RLM.

The RLM proposed in this Draft Rule Change Report also produces clearer price signals about the potential additions to the fleet that might best complement the existing fleet of Intermittent Generators. These clearer signals, combined with the increased transparency provided by the proposed RLM, should allow potential investors to make more informed investment decisions, which is likely to lead to increased competition and a more efficient and reliable facility mix in the WEM.

The Rule Change Panel considers that the proposed RLM, as amended in this Draft Rule Change Report will better achieve Wholesale Market Objectives (a), (b), (c) and (d) by providing clearer price signals for investment in Intermittent Generation.

Improved Responsiveness to Changes to the WEM

The WEM has experienced material changes since the implementation of the current RLM in 2012, and further changes are expected over the next few years. The RLM proposed in the Draft Rule Change Report will be able to respond to these changes by:

- accounting for the growth of small-scale PV by adjusting the system demand profile to account for historical and expected future increases in the level of small-scale PV penetration. This will remove a source of error from the determination of the Relevant Levels, and avoid discrimination by ensuring that facilities whose performance is sensitive to PV penetration levels are assessed appropriately;
- being flexible enough to handle new intermittent technology types and Facilities comprising multiple intermittent technologies without additional administrative burden or metering costs, which will avoid discrimination and encourage competition and innovation; and
- determining Relevant Levels in 4 successive rounds (committed Facility CRC, proposed Facility CRC, Early CRC and Conditional CRC), which will prevent inefficient and discriminatory distortions of the Relevant Levels and NAQs of committed Facilities because of the inclusion of proposed Facilities that do not subsequently receive Capacity Credits in the calculation of the ELCC for the fleet of committed Facilities.

The Rule Change Panel considers that the proposed RLM, as amended in this Draft Rule Change Report will better achieve Wholesale Market Objectives (a), (b), (c) and (d) by being more responsive to changes in the WEM.

6.5 Protected Provisions, Reviewable Decisions and Civil Penalties

This Rule Change Proposal does not amend any Protected Provisions, Reviewable Decisions, or civil penalty provisions; nor does the Rule Change Panel consider that any of the proposed new clauses should be civil penalty provisions.

6.6 Practicality and Cost of Implementation

6.6.1 Cost

AEMO has indicated that the implementation of the proposed RLM as outlined in this Draft Rule Change Report would cost around $470,000. The Rule Change Panel notes that AEMO's estimate is based on information about the main aspects of the draft decision and that AEMO did not receive the draft Amending Rules prior to publication of this report. The Rule Change Panel will engage with AEMO to provide a more thorough cost estimate during the second submission period. Note that AEMO's cost estimate may noticeably vary as aspects of the proposed amendments become clearer.

Collgar Wind Farm noted in its first period submission that implementing the proposed RLM will require development of an internal model to assist with forecasting and planning; and that supporting systems, training and documentation will need to be prepared to support the integration of the proposed changes into its internal business processes. Collgar estimated that the total cost of implementation could be in the range of $50,000 to $75,000.

6.6.2 Practicality

AEMO indicated that it would require approximately eight months for the implementation of the proposed RLM as outlined in this Draft Rule Change Report. The Rule Change Panel notes that AEMO's estimate is based on information about the main aspects of the draft decision and that AEMO did not receive the Draft Amending Rules before the publication of this report.

Collgar Wind Farm noted in its first period submission that implementing the proposed RLM will require development of an internal model to assist with forecasting and planning; and that supporting systems, training and documentation will need to be prepared to support the integration of the proposed changes into its internal business processes.

6.7 Proposed Commencement

The Amending Rules are proposed to commence at **8:00 AM** on **6 August 2021**. The commencement date is subject to change in the Final Rule Change Report.

7. Amending Rules

The Rule Change Panel proposes to implement the following Amending Rules (~~deleted text~~, added text, clauses that are included for context but not amended):

4.9. Process for Applying for Certification of Reserve Capacity

…

4.9.5. If AEMO assigns Certified Reserve Capacity to a Facility for a future Reserve Capacity Cycle under section 4.11 ("**Conditional Certified Reserve Capacity**"):

(a) the Conditional Certified Reserve Capacity is conditional upon the information included in the application for Certified Reserve Capacity remaining correct as at the date and time specified in clause 4.1.11 for that future Reserve Capacity Cycle;

(b) the Market Participant holding the Conditional Certified Reserve Capacity must, in accordance with clauses 4.9.1 and 4.9.3, re-lodge an application for Certified Reserve Capacity with AEMO between the date and time specified in clause 4.1.7 and the time specified in clause 4.1.11 for that future Reserve Capacity Cycle;

(c) if AEMO is satisfied that the application re-lodged in accordance with clause 4.9.5(b) is consistent with the information upon which the Conditional Certified Reserve Capacity was assigned and is correct, then AEMO must confirm:

i. the Certified Reserve Capacity;

ii. [Blank]; and

iii. the Reserve Capacity Security or DSM Reserve Capacity Security levels,

that were previously conditionally assigned, set or determined by AEMO, ~~subject to~~ except that the Certified Reserve Capacity for an Intermittent Generating System ~~being~~ must be redetermined and assigned in accordance with clause 4.11.2(b) for the current Reserve Capacity Cycle; and

(d) if the application re-lodged in accordance with clause 4.9.5(b) is found by AEMO to be inaccurate or is not consistent with the information upon which the Conditional Certified Reserve Capacity was assigned, then AEMO must process the application without regard for the Conditional Certified Reserve Capacity.

…

4.9.11. AEMO must document how it will determine the system demand profiles required under Step 4.2 of Appendix 9 in the WEM Procedure specified in clause 4.9.10.

...

4.10. Information Required for the Certification of Reserve Capacity

…

4.10.2. The types of Facilities eligible to use the method~~ology~~ described in clause 4.11.2(b), for the purpose of assigning Certified Reserve Capacity or Conditional Certified Reserve Capacity to the Facility are:

(a) components of Semi-Scheduled Facilities that are Intermittent Generating Systems;

(b) Non-Scheduled Facilities, except Non-Scheduled Facilities comprising only Electric Storage Resources that have not been in operation for the full ~~period of performance assessment identified in step 1(a) of the Relevant Level Methodology~~ RLM Reference Period for the current Reserve Capacity Cycle; and

(c) Non-Scheduled Facilities comprising only Electric Storage Resources that have been in operation for the full ~~period of performance assessment identified in step 1(a) of the Relevant Level Methodology~~ RLM Reference Period for the current Reserve Capacity Cycle.

4.10.3. An application for certification of Reserve Capacity for a Facility, or component of a Facility, that is to be assessed using the method~~ology~~ described in clause 4.11.2(b) for a Facility, or relevant component of a Facility, that:

(a) is yet to enter service;

(b) is to re-enter service after significant maintenance;

(c) is to re-enter service after having been upgraded; or

(d) has not operated with the configuration outlined in clause 4.10.1(dA) for the full ~~period of performance assessment identified in step 1(a) of the Relevant Level Methodology~~ RLM Reference Period for the current Reserve Capacity Cycle,

must include a report prepared by an expert accredited by AEMO in accordance with clause 4.11.6. AEMO will use the report to assign Certified Reserve Capacity for the Facility, or the relevant component of the Facility, that is to be assessed using the method~~ology~~ described in clause 4.11.2(b) and to determine the Required Level for that Facility in accordance with clause 4.11.3B(b).

4.10.3A. A report provided under clause 4.10.3 must include:

(a) for each Trading Interval during the ~~period identified in step 1(a) of the Relevant Level Methodology,~~ RLM Reference Period for the current Reserve Capacity Cycle a reasonable estimate of the expected energy that would have been sent out by the Facility or the component of the Facility assessed using the method~~ology~~ described in clause 4.11.2(b) had it been in operation. This estimate must factor in the effect of Planned Outages or Forced Outages on the sent out energy;

…

…

4.11. Setting Certified Reserve Capacity

4.11.1. Subject to clause 4.11.12, AEMO must apply the following principles in assigning a quantity of Certified Reserve Capacity to a Facility or relevant component of a Facility for the Reserve Capacity Cycle for which an application for Certified Reserve Capacity has been submitted in accordance with section 4.10:

(a) the Certified Reserve Capacity for a Scheduled Facility comprising only Non-intermittent Generating Systems for a Reserve Capacity Cycle must not exceed AEMO's reasonable expectation of the amount of capacity likely to be available, after netting off capacity required to serve Intermittent Loads, embedded loads and Parasitic Loads, for Peak Trading Intervals on Business Days from the Trading Day starting 1 October in Year 3 of the Reserve Capacity Cycle to the end of July in Year 4 of the Reserve Capacity Cycle, assuming an ambient temperature of ~~41oC~~ 41 degrees Celsius;

(b) for a Scheduled Facility comprising only Non-Intermittent Generating Systems, the Certified Reserve Capacity must not exceed the sum of the capacities specified in clauses 4.10.1(e)(ii) and 4.10.1(e)(iii);

(bA) where the Facility is an Energy Producing System, the Certified Reserve Capacity must not exceed the Declared Sent Out Capacity for the Facility notified to AEMO under clause 4.10.1(bA)(iii);

(bB) where two or more Facilities share a Declared Sent Out Capacity, the total quantity of Certified Reserve Capacity assigned to those Facilities must not exceed the Declared Sent Out Capacity;

(bC) for a Scheduled Facility containing an Electric Storage Resource or Semi-Scheduled Facility containing an Electric Storage Resource, the total quantity of Certified Reserve Capacity determined for the Electric Storage Resource must be determined by AEMO in accordance with clause 4.11.3;

(bD) for a Non-Scheduled Facility comprising only an Electric Storage Resource, including Small Aggregation of aggregated Electric Storage Resources, the total quantity of Certified Reserve Capacity must be:

i. determined in accordance with the Relevant Level Method~~ology~~ determined in accordance with clause 4.11.2; or

ii. if the Electric Storage Resource has not been in operation for the full ~~period of performance assessment identified in step 1(a) of the Relevant Level Methodology~~ RLM Reference Period for the current Reserve Capacity Cycle, determined in accordance with clause 4.11.3;

(bE) for a Non-Scheduled Facility, excluding Non-Scheduled Facilities under clause 4.11.1(bD)(ii), the total quantity of Certified Reserve Capacity assigned to the Facility must be determined in accordance with the Relevant Level Method~~ology~~, determined in accordance with clause 4.11.2;

…

…

4.11.2. Where an applicant submits an application for Certified Reserve Capacity, in accordance with clause 4.10, and AEMO is required to use the method~~ology~~ described in clause 4.11.2(b) to apply to an Intermittent Generating System or a Non-Scheduled Facility (excluding where clause 4.11.1(bD)(ii) applies), AEMO:

(a) [Blank];

(aA) [Blank]; and

(b) subject to clause 4.11.12, must assign a quantity of Certified Reserve Capacity to the relevant Facility or relevant component of a Facility for the Reserve Capacity Cycle equal to the Relevant Level as determined in accordance with the Relevant Level Method~~ology~~, but subject to clauses 4.11.1(bA), 4.11.1(bB), 4.11.1(c), 4.11.1(f) and 4.11.1(h).

…

4.11.3C. For each three year period, beginning with the period commencing on 1 January ~~2015~~ 2024, the Economic Regulation Authority must, by 1 April of the first year of that period, conduct a review of the Relevant Level Method~~ology~~. In conducting the review, the Economic Regulation Authority ~~must~~:

(a) must examine the effectiveness of the Relevant Level Method~~ology~~ in meeting the Wholesale Market Objectives; and

~~(b) determine the values of the parameters K and U in step 17 of the Relevant Level Methodology to be applied for each of the three Reserve Capacity Cycles commencing in the period,~~

(b) may examine any other matters that the Economic Regulation Authority considers to be relevant.

~~and the Economic Regulation Authority may examine any other matters that the Economic Regulation Authority considers to be relevant.~~

…

4.11.3E. At the conclusion of a review under clause 4.11.3C, the Economic Regulation Authority must publish a final report containing:

(a) details of the Economic Regulation Authority's review of the Relevant Level Method~~ology~~;

(b) a summary of the submissions received during the consultation period;

(c) the Economic Regulation Authority's response to any issues raised in those submissions; and

~~(d) the values of the parameters K and U determined under clause 4.11.3C; and~~

(~~e~~d) any recommended amendments to the Relevant Level Method~~ology~~ which the Economic Regulation Authority intends to progress as a Rule Change Proposal.

…

7.7. Dispatch Instructions

...

7.7.5A. AEMO must develop a WEM Procedure specifying:

(a) information that a Market Participant must provide to AEMO, for each of the Market Participant's Non-Scheduled Generators, and for each Trading Interval, for the purposes of:

i. the estimate referred to in clause 7.7.5A(b);

ii. the revised estimate referred to in clause 7.7.5A(c);

iii. ~~step 6~~ Step 2.5 of Appendix 9; or

iv. ~~step 6A~~ Step 2.6 of Appendix 9;

(b) for the purposes of clause 7.7.5B and the Relevant Level Method~~ology~~ – one or more methods that may be used to estimate the maximum quantity of sent out energy (in MWh) that a Non-Scheduled Generator would have generated in a Trading Interval had a Dispatch Instruction not been issued for that Facility and for that Trading Interval;

(c) for the purposes of the Relevant Level Method~~ology~~ only – the process for revising an estimate that was made strictly in accordance with one of the methods that, under clause 7.7.5A(b), must be specified in the WEM Procedure; and

(d) for the purposes of clause 7.13.1C(e) – one or more methods that may be used to estimate the decrease in the output (in MWh) of each of Synergy's Non-Scheduled Generators as a result of an instruction from AEMO to deviate from the Dispatch Plan or change their commitment or output in accordance with clause 7.6A.3(a).

...

10.5. Public Information

10.5.1. AEMO must set the class of confidentiality status for the following information under clause 10.2.1 as Public and AEMO must make each item of information available from or via the WEM Website after that item of information becomes available to AEMO:

…

(f) the following Reserve Capacity information (if applicable):

…

x. the ~~following~~ information ~~identified~~ for a Reserve Capacity Cycle ~~under~~ specified in Step 11 of the Relevant Level Method~~ology:~~;

~~1. the Existing Facility Load for Scheduled Generation for each Trading Interval in the five year period determined under Step 1(a) of Appendix 9; and~~

~~2. the 12 Trading Intervals occurring on separate Trading Days with the highest Existing Facility Load for Scheduled Generation for each 12 month period in the five year period; and~~

…

…

…

11. Glossary

…

~~**Existing Facility Load for Scheduled Generation**: Means the MWh quantity determined for a Trading Interval under step 7 of the Relevant Level Methodology.~~

…

~~**New Facility Load for Scheduled Generation**: Means, for a new or upgraded Facility that has applied to be assigned Certified Reserve Capacity under clause 4.11.2(b), the MWh quantity determined for a Trading Interval under step 11 of the Relevant Level Methodology for that Facility and the relevant Reserve Capacity Cycle.~~

…

Relevant Level: Means the MW quantity determined by AEMO in accordance with the Relevant Level Method~~ology~~.

Relevant Level Method~~ology~~: Means the method of determining the Relevant Level specified in Appendix 9.

…

RLM Reference Period: For a Reserve Capacity Cycle, the seven-year period ending at 8:00 AM on 1 April of Year 1 of that Reserve Capacity Cycle.

...

The Rule Change Panel also proposes to replace Appendix 9 with the following (no mark-up has been applied because all the text is proposed to be replaced):

Appendix 9: Relevant Level Determination

Part A: Introduction

Appendix 9 Overview
• Part A of this Appendix 9 sets out definitions and introductory material.
• Part B sets out the steps of the Relevant Level Method.
• Part C, D and E contain subroutines which are called upon by Part B and each other.

Interpretation and Definitions

A.1. This Appendix 9 presents the method for determining the Relevant Levels for Facilities or parts of Facilities ("**Candidates**") for which:

(a) Market Participants have applied for:

i. Certified Reserve Capacity for a given Reserve Capacity Cycle ("**Current Reserve Capacity Cycle**") under section 4.9;

ii. Conditional Certified Reserve Capacity for a future Reserve Capacity Cycle under section 4.9, where AEMO is required under clause 4.9.7A to process the application at the time it processes applications for Certified Reserve Capacity for the Current Reserve Capacity Cycle; or

iii. Early Certified Reserve Capacity for a Reserve Capacity Cycle under clause 4.28C.2, where AEMO is required to process the application at the time it processes applications for Certified Reserve Capacity for the Current Reserve Capacity Cycle;

(b) the Market Participants' applications include all required supporting information and are deemed by AEMO to be complete; and

(c) the Certified Reserve Capacity, Conditional Certified Reserve Capacity or Early Certified Reserve Capacity (as applicable) is required to be determined in accordance with clause 4.11.2(b).

A.2. In this Appendix 9:

(a) a reference to a step is to the process step so numbered in this Appendix 9;

(b) the steps in Parts B to E are to be carried out sequentially, unless stated otherwise;

(c) "**Reference Period**" is the RLM Reference Period for the Current Reserve Capacity Cycle;

(d) the full operation date of a Candidate for the Reserve Capacity Cycle ("**Full Operation Date**") is:

i. the date provided under clause 4.10.1(c)(iii)(7) or revised in accordance with clause 4.27.11A, where at the time the application is made the Facility, or part of the Facility (as applicable) is yet to enter service (excluding a part of a Facility that is an Electric Storage Resource for which Certified Reserve Capacity is not being assessed in accordance with the methodology in this Appendix 9); or

ii. the date most recently provided for a Reserve Capacity Cycle under clause 4.10.1(k) otherwise;

(e) a "**Committed Candidate**" is a Candidate which is the subject of an application for Certified Reserve Capacity for the Current Reserve Capacity Cycle and is deemed by AEMO to be committed;

(f) a "**Proposed Candidate**" is a Candidate which is the subject of an application for Certified Reserve Capacity for the Current Reserve Capacity Cycle and is deemed by AEMO to not be committed;

(g) an "**Early CRC Candidate**" is a Candidate which is the subject of an application for Early Certified Reserve Capacity for a future Reserve Capacity Cycle that AEMO is required, under clause 4.28C.7, to process at the time it processes applications for Certified Reserve Capacity for the Current Reserve Capacity Cycle;

(h) a "**Conditional CRC Candidate**" is a Candidate which is the subject of an application for Conditional Certified Reserve Capacity for a future Reserve Capacity Cycle that AEMO is required, under clause 4.9.7A, to process at the time it processes applications for Certified Reserve Capacity for the Current Reserve Capacity Cycle;

(i) "**Capacity Outage Probability Table**" has the meaning given in Step 3; and

(j) the "**Candidate Type**" of a Candidate is determined in accordance with Step 1.

A.3. AEMO must determine the Relevant Levels for the Candidates for the Current Reserve Capacity Cycle by following each of the steps set out in Part B, using the subroutines in Parts C, D and E as specified.

A.4. The explanatory notes which appear in boxes in this Appendix are intended as high-level guides for the reader. They do not fully describe the process, and do not use precise terminology. They are of no legal effect and are to be disregarded in interpreting this Appendix.

Part B: Process Steps

Part B Overview

This Part B sets out the Relevant Level Method's sequential steps.

The method undertakes an assessment of the **"Effective Load Carrying Capability"** (**"ELCC"**) of four fleets of Candidates, using historical-but-adjusted demand data from the 7-year **"Reference Period"**. The ELCC of a fleet of Candidates is a measure of the additional demand the system can cover after the addition of the fleet, while maintaining the same level of system reliability. The measure of system reliability used in this method is the **"Loss of Load Expectation"** over the Reference Period. The process for determining the ELCC of a candidate fleet is described in Part D.

The first assessment is for the fleet of Committed Candidates, followed in turn by the assessments for the fleets of Proposed Candidates, Early CRC Candidates and finally Conditional CRC Candidates; each time measuring the marginal contribution of the candidate fleet, after the contribution of the earlier fleets (plus the non-intermittent fleet) have been taken into account.

Each fleet ELCC is distributed between the member Candidates using the Delta Method. The Delta Method allocates the fleet ELCC between the Candidates in a manner that reflects the interactive effects between each Candidate and the rest of the fleet. The Delta Method is described in Part E.

The Relevant Level for a large Candidate is the value allocated by the Delta Method.

Small Candidates, which could be affected by rounding limitations, are processed differently. Small Committed Candidates are divided into groups and the Delta Method is used to assign a share of the fleet ELCC to each group. Then the Relevant Levels of the group members are determined by allocating the group values between the members according to their performance in a selection of Trading Intervals with high loss of load probabilities.

Relevant Levels are calculated for small Proposed Candidates, Early CRC Candidates and Conditional CRC Candidates on an individual basis using a calculation based on the one used for small Committed Candidates. This is because there may not be enough of these Candidates to form groups that can be processed using the Delta Method.

Step 1: Determine Candidate Types

Step 1 Overview

Most Candidates will participate in the process on their own. Small, Non-Scheduled Facilities will need to be grouped and processed together, to make sure they are not disadvantaged in the incremental processes below.

1.1. Determine the Candidate Type of each Candidate as follows:

(a) if the Candidate is (or is proposed to be) registered as a Non-Scheduled Facility, then the Candidate is a **"Small Candidate"** and:

i. classify all Small Candidates which comprise only a generating system fuelled by biogas, as having the Candidate Type "small biogas"; and

ii. classify all other Small Candidates as having the Candidate Type "small non-biogas"; and

(b) each other Candidate is a **"Standalone Candidate"** and is classified as having the Candidate Type "standalone".

Step 2: Determine Candidates' Historical Output

Step 2 Overview
The calculations in this process are to be done using Candidates' actual SWIS generation data from every Trading Interval in the Reference Period. Estimated values are used if a Candidate had not commenced operating for part or all of the Reference Period (Step 2.1).
Adjustments are made to the raw output data to correct for Trading Intervals where:
• a Facility was directed by AEMO to restrict its output under a Dispatch Instruction (Step 2.3);
• a Balancing Portfolio Facility was directed by AEMO to deviate from its Dispatch Plan (Step 2.4);
• a Facility was affected by a Consequential Outage (Step 2.5); or
• a Facility was constrained off under a Network Control Service Contract (Step 2.6).

2.1. For each Candidate, determine:

(a) for each Trading Interval (if any) in the Reference Period that falls after 8:00 AM on the Full Operation Date for the Candidate, the quantity of energy (in MWh) sent out by the Candidate using Meter Data Submissions, which, for a Candidate that is a Semi-Scheduled Facility containing an Electric Storage Resource, must exclude any generation or consumption measured by the Electric Storage Resource Metering required to be installed in accordance with clause 2.29.12; and

(b) for each Trading Interval (if any) in the Reference Period that falls before 8:00 AM on the Full Operation Date for the Candidate, an estimate of the quantity of energy (in MWh) that would have been sent out by the Candidate in the Trading Interval, if it had been in operation with the configuration proposed under clause 4.10.1(dA) in the relevant application for certification of Reserve Capacity. The estimates must reflect the estimates in the expert report provided for the Candidate under clause 4.10.3, unless AEMO reasonably considers the estimates in the expert report to be inaccurate.

2.2. For each Candidate, identify any Trading Intervals in the Reference Period that fall after 8:00 AM on the Full Operation Date for the Candidate where:

(a) the parent Facility, other than a Facility in the Balancing Portfolio, was directed to restrict its output under a Dispatch Instruction as provided in a schedule under clause 7.13.1(c); or

(b) the parent Facility, if in the Balancing Portfolio, was instructed by AEMO to deviate from its Dispatch Plan or change its commitment or output as provided in a schedule under clause 7.13.1C(d); or

(c) the parent Facility was affected by a Consequential Outage; or

(d) the parent Facility was directed to restrict its output under an Operating Instruction issued in accordance with a Network Control Service Contract, as provided in a schedule under clause 7.13.1(cC).

2.3. For each Candidate and Trading Interval identified in Step 2.2(a):

(a) identify the actual quantity as determined in Step 2.1(a) if:

i. AEMO has made a revised estimate of the maximum quantity in accordance with clause 7.7.5A(c) and the WEM Procedure specified in clause 7.7.5A; and

ii. the revised estimate of the maximum quantity is lower than the actual quantity as determined in Step 2.1(a);

(b) identify the actual quantity as determined in Step 2.1(a) if:

i. Step 2.3(a) does not apply; and

ii. the estimated maximum quantity determined by AEMO under clause 7.13.1(eF) is lower than the actual quantity as determined in Step 2.1(a); and

(c) if Steps 2.3(a) and 2.3(b) do not apply:

i. identify the revised estimate of the maximum quantity determined by AEMO in accordance with the WEM Procedure specified in clause 7.7.5A; or

ii. if there is no revised estimate, identify the estimate determined by AEMO under clause 7.13.1(eF).

2.4. For each Candidate and Trading Interval identified in Step 2.2(b) use:

(a) the estimate recorded by AEMO under clause 7.13.1C(e); and

(b) the quantity determined for the Candidate and Trading Interval in Step 2.1(a),

to estimate the quantity of energy (in MWh) that would have been sent out by the Candidate had it not complied with AEMO's instruction to change its commitment or output during the Trading Interval.

2.5. For each Candidate and Trading Interval identified in Step 2.2(c) use:

(a) the Unadjusted Consequential Outage Quantity for the Candidate for the Trading Interval;

(b) the quantity determined for the Candidate in Step 2.1(a); and

(c) the information recorded by AEMO under clause 7.13.1C(a),

to estimate the quantity of energy (in MWh) that would have been sent out by the Candidate had it not been affected by the Consequential Outage during the Trading Interval.

2.6. For each Candidate and Trading Interval identified in Step 2.2(d) use:

(a) the schedule of Operating Instructions determined by AEMO under clause 7.13.1(cC);

(b) the quantity determined for the Candidate and Trading Interval in Step 2.1(a); and

(c) the information recorded by AEMO under clause 7.13.1C(a),

to estimate the quantity of energy (in MWh) that would have been sent out by the Candidate had it not been subject to an Operating Instruction during the Trading Interval.

2.7. Determine the Historical Output for each Candidate for each Trading Interval in the Reference Period as:

(a) for Trading Intervals that fall after 8:00 AM on the Full Operation Date for the Candidate, the MWh quantity determined in Step 2.1(a), or estimated in Steps 2.3, 2.4, 2.5 or 2.6 as applicable, multiplied by 2 to convert to units of MW; and

(b) for Trading Intervals that fall before 8:00 AM on the Full Operation Date for the Candidate, the MWh quantity determined in step 2.1(b) for the Candidate and Trading Interval, multiplied by 2 to convert to units of MW.

Step 3: Determine the Capacity Outage Probability Tables

Step 3 Overview

Capacity outage probability tables (**"COPTs"**) are used to determine the probability that the combined available capacity of the non-intermittent fleet (including Demand Side Programmes and large Electric Storage Resources) (**"Non-Intermittent Facilities"**) will fall short of the system demand in a Trading Interval.

The tables are built by aggregating the reserve capacity of the expected non-intermittent fleet for the current Reserve Capacity Cycle, and applying the Forced Outage Rate determined by AEMO for each facility. This creates a look-up list showing the probability that the combined magnitude of Forced Outages of the non-intermittent fleet would exceed a particular MW level.

Although the Relevant Level Method uses historical system demand (measured as generation facilities' outputs), it uses that demand to assess outage probabilities for the non-intermittent fleet to which AEMO is proposing to assign Certified Reserve Capacity for the current Reserve Capacity Cycle, not the fleet which was in existence at that historical time.

Before building the COPTs, a **"Default Capacity Obligation Quantity"** or **"DCOQ"** is calculated for each Non-Intermittent Facility for each Trading Interval. The DCOQ, which measures the facility's obligation to contribute to meeting system demand, is set to the facility's expected Certified Reserve Capacity (scaled to reflect the Reserve Capacity Requirement for the current Reserve Capacity Cycle) for the Trading Intervals where the facility is meant to be available, and to zero for any other Trading Intervals (Steps 3.4 and 3.5).

There will be several COPTs, reflecting the fact that the availability of Non-Intermittent Facilities will be different at different times (Step 3.6). Non-Intermittent Generating Systems are expected to be available at all times, Demand Side Programmes between 8:00 AM and 8:00 PM on Business Days, and Electric Storage Resources for a 4-hour period each day to be determined by AEMO. This will initially produce four **"Trading Interval Groups"**, each with its own COPT:

- one for Trading Intervals where only Non-Intermittent Generating Systems are required to operate;

- one for Trading Intervals where Non-Intermittent Generating Systems and Electric Storage Resources are required to operate;
- one for Trading Intervals where Non-Intermittent Generating Systems and Demand Side Programmes are required to operate; and
- one for Trading Intervals where all three are required to operate – Non-Intermittent Generating Systems, Demand Side Programmes and Electricity Storage.

Each COPT is built iteratively, adding in one Non-Intermittent Facility at a time (the order in which facilities are added makes no difference), taking account of each facility's DCOQ and probability of experiencing a Forced Outage, to calculate the cumulative probability (P(X)) that the non-intermittent fleet would experience at least X MW of Forced Outages, for a series of values of X (Step 3.7).

For each Trading Interval Group, **"NIF_Max"** is the sum of the DCOQs of the Non-Intermittent Facilities which are required to be available in the associated Trading Intervals – this is the maximum theoretical available capacity if no Non-Intermittent Facility had an outage. The COPT for the Trading Interval Group lists each 0.1 MW increment of X from 0 to NIF_Max and gives the corresponding value of P(X).

The COPTs are used in Part C to determine loss of load probabilities.

3.1. Identify all:

(a) Non-Intermittent Generating Systems that are Facilities or components of Facilities that are registered (or proposed to be registered) as Scheduled Facilities or Semi-Scheduled Facilities;

(b) Demand Side Programmes; and

(c) Electric Storage Resources that are Facilities or components of Facilities that are registered (or proposed to be registered) as Scheduled Facilities or Semi-Scheduled Facilities,

that AEMO intends to assign Certified Reserve Capacity for the Current Reserve Capacity Cycle and deems to be committed ("**Non-Intermittent Facilities**").

3.2. Set the Forced Outage Rate for each Non-Intermittent Facility that is a Non-Intermittent Generating System or Electric Storage Resource identified in Step 3.1(a) or 3.1(c) as the Forced Outage rate, estimated using the WEM Procedure specified in clause 4.9.10 for the Current Reserve Capacity Cycle, or otherwise if not available, AEMO's expectation of the expected Forced Outage rate of the Facility determined under clause 4.11.1(h)(ii).

3.3. Set the Forced Outage Rate for each Non-Intermittent Facility that is a Demand Side Programme to zero.

3.4. Determine the Default Capacity Obligation Quantity Adjustment Factor as:

$$\text{DCOQ\_Adj} = \frac{\text{RCR}}{\sum_{f \in \text{NI Facilities}} \text{CRC}(f)}$$

where:

(a) RCR is the Reserve Capacity Requirement for the Current Reserve Capacity Cycle;

(b) f∈NI Facilities denotes all Non-Intermittent Facilities identified in Step 3.1; and

(c) CRC(f) is the quantity of Certified Reserve Capacity that AEMO intends to assign Non-Intermittent Facility f for the Current Reserve Capacity Cycle.

3.5. Determine the "**Default Capacity Obligation Quantity**" for each Non-Intermittent Facility f identified in Step 3.1 for each Trading Interval t in the Reference Period as follows:

(a) If:

i. Non-Intermittent Facility f is a Non-Intermittent Generating System;

ii. Non-Intermittent Facility f is an Electric Storage Resource and Trading Interval t meets the criteria for an Electric Storage Resource Obligation Interval published by AEMO for the Current Reserve Capacity Cycle under clause 4.11.3A(a); or

iii. Non-Intermittent Facility f is a Demand Side Programme and Trading Interval t falls between 8:00 AM and 8:00 PM on a Business Day, then:

DCOQ(f,t) = ROUND(CRC(f) x DCOQ_Adj)

where:

iv. the ROUND() function rounds a number to one decimal place;

v. CRC(f) is the quantity of Certified Reserve Capacity that AEMO intends to assign Non-Intermittent Facility f for the Current Reserve Capacity Cycle; and

vi. DCOQ_Adj is the Default Capacity Obligation Quantity Adjustment Factor determined in Step 3.4; and

(b) DCOQ(f,t) = 0 otherwise.

3.6. Divide the Trading Intervals in the Reference Period into groups ("**Trading Interval Groups**") so that the Default Capacity Obligation Quantities of the Non-Intermittent Facilities are the same for all the Trading Intervals in a Trading Interval Group.

3.7. For each Trading Interval Group, develop a Capacity Outage Probability Table as follows:

(a) Identify the Non-Intermittent Facilities that have non-zero Default Capacity Obligation Quantities during the Trading Intervals in the Trading Interval Group.

(b) Determine NIF_Max for the Trading Interval Group as the sum of the Default Capacity Obligation Quantities of the Non-Intermittent Facilities identified in Step 3.7(a) during Trading Intervals in the Trading Interval Group.

(c) Set P(X) to 0 for each MW quantity X (that is a multiple of 0.1 MW) between 0 and NIF_Max.

(d) For each Non-Intermittent Facility f identified in Step 3.7(a):

i. Set X = 0.

ii. Set $P(X) = (1 - FOR(f)) \times P_{prev}(X) + FOR(f) \times P_{prev}(X - DCOQ(f))$

where:

1. FOR(f) is the Forced Outage Rate for Non-Intermittent Facility f determined in Step 3.2 or 3.3;

2. for any given Y, $P_{prev}(Y)$ is:

1 if Y is less than or equal to 0; otherwise

0 if f is the first Non-Intermittent Facility to be processed for the Trading Interval Group; otherwise

the value of P(Y) determined for the most recently processed Non-Intermittent Facility; and

3. DCOQ(f) is the Default Capacity Obligation Quantity for Non-Intermittent Facility f during Trading Intervals in the Trading Interval Group.

iii. If P(X) is greater than 0 and X is less than NIF_Max then increment X by 0.1 and return to Step 3.7(d)(ii).

(e) The Capacity Outage Probability Table for the Trading Interval Group is a table listing each MW quantity X from 0 to NIF_Max and the corresponding values of P(X).

Step 4: Determine Scaled Demand Profile

Step 4 Overview

Step 4 adjusts the actual historical system demand profile for several factors, to create the **"Scaled Demand Profile"** which will be used to assess the Candidates' contribution.

- The first step involves taking total recorded output from generators in each Trading Interval, and increasing it to add back load which was removed due to a demand side response or the interruption of an Interruptible Load, and any load not served due to involuntary load shedding (Step 4.1). This gives a fairer view of actual historical load in the Trading Interval.
- Next, the demand profile is adjusted downwards to reflect growth in DER resources (specifically behind-the-meter photovoltaic capacity) from the level in the historical Trading Interval in question, to the level they are forecast to have reached at the start of the relevant Capacity Year (Step 4.2). This adjustment is made to make the Scaled Demand Profile better reflect the level of DER penetration expected in the relevant Capacity Year.
- Finally, for a similar reason, the demand profile is adjusted to allow for the capacity contribution of Non-Scheduled Facilities that are Electric Storage Resources, other than those facilities that are Candidates in this process (Step 4.3).

4.1. Determine the Observed Demand (in MW) for each Trading Interval in the Reference Period as follows:

Observed_Demand = (Total_Generation + DSP_Reduction
+ Interruptible_Reduction + Involuntary_Reduction) x 2

where:

(a) Total_Generation is the total sent out generation of all Registered Facilities, as determined from Meter Data Submissions;

(b) DSP_Reduction is the total quantity of Deemed DSM Dispatch for all Demand Side Programmes for that Trading Interval;

(c) Interruptible_Reduction is the total quantity by which all Interruptible Loads reduced their consumptions in accordance with the terms of an Ancillary Service Contract, as recorded by AEMO under clause 7.13.1C(c); and

(d) Involuntary_Reduction is the total quantity of energy not served due to involuntary load shedding (manual and automatic), as recorded by AEMO under clause 7.13.1C(b).

4.2. Determine the DER Adjusted Demand Profile for the Reference Period by adjusting the Observed Demand for each Trading Interval determined under Step 4.1 to account for the change in behind-the-meter photovoltaic capacity in the SWIS over time, so that the resulting system demand is equal to AEMO's best estimate of what the Observed Demand would have been in that Trading Interval if the level of behind-the-meter photovoltaic capacity had been equal to the level that AEMO expects to exist on 1 October in Year 3 of the Current Reserve Capacity Cycle.

4.3. Determine the Scaled Demand Profile for the Reference Period by adjusting the DER Adjusted Demand Profile to reduce the system demand for each Trading Interval in the Reference Period that would meet the criteria for an Electric Storage Resource Obligation Interval published by AEMO for the Current Reserve Capacity Cycle under clause 4.11.3A(a) by the total quantity of Certified Reserve Capacity that AEMO intends to assign to Non-Scheduled Facilities that are not Candidates for the Current Reserve Capacity Cycle.

Step 5: Determine Ex-Committed Demand Profile

Step 5 Overview
This step determines the **"Ex-Committed Demand Profile"**, by subtracting the Historical Output of the Committed Candidates from the Scaled Demand determined in Step 4 for each Trading Interval in the Reference Period. The Ex-Committed Demand Profile is used to identify half of the Trading Intervals used to calculate Facility Average Performance Levels for Small Candidates in Step 6, and to calculate the Committed Fleet ELCC in Step 7.

5.1. Determine the Ex-Committed Demand Profile for the Reference Period so that for each Trading Interval t in the Reference Period:

$$\text{Ex-Committed\_Demand}(t) = \text{Scaled\_Demand}(t) - \sum_{c \in \text{Committed}} \text{Historical\_Output}(c,t)$$

where:

(a) Ex-Committed_Demand(t) is the system demand (in MW) specified for Trading Interval t in the Ex-Committed Demand Profile;

(b) Scaled_Demand(t) is the system demand (in MW) specified for Trading Interval t in the Scaled Demand Profile;

(c) c ∈ Committed denotes all Committed Candidates; and

(d) Historical_Output(c,t) is the Historical Output value determined for Candidate c and Trading Interval t in Step 2.7.

Step 6: Determine Facility Average Performance Levels for Small Candidates

Step 6 Overview

This step determines the **"Facility Average Performance Level"** for each Small Candidate. These values are used in Steps 7.5, 8.1, 9.1 and 10.1 to determine the Relevant Levels for these Candidates.

The Facility Average Performance Level of a Small Candidate is the mean of historical output of the Small Candidate over two sets of Trading Intervals with the highest loss of load probability for two demand profiles, namely the Scaled Demand Profile determined under Step 4, and the Ex-Committed Demand Profile determined under Step 5.

6.1. Identify the 50 Trading Intervals in the Reference Period with the highest loss of load probability determined in accordance with Step C.1 using the following input:

(a) for "Demand Profile" use the Scaled Demand Profile.

6.2. Identify the 50 Trading Intervals in the Reference Period with the highest loss of load probability determined in accordance with Step C.1 using the following input:

(a) for "Demand Profile" use the Ex-Committed Demand Profile.

6.3. Determine the Facility Average Performance Level for each Small Candidate c identified in Step 1.1(a) as:

$$\text{FAPL}(c) = \frac{\left(\sum_{t \in \text{High Scaled}} \text{Historical\_Output}(c,t) + \sum_{t \in \text{High Ex-Committed}} \text{Historical\_Output}(c,t)\right)}{100}$$

where:

(a) t ∈ High Scaled denotes the 50 Trading Intervals identified in Step 6.1;

(b) t ∈ High Ex-Committed denotes the 50 Trading Intervals identified in Step 6.2; and

(c) Historical_Output(c,t) is the Historical Output value determined for Candidate c and Trading Interval t in Step 2.7.

Step 7: Determine Relevant Levels for Committed Candidates

Step 7 Overview
This step and the next three (Steps 8, 9 and 10) follow a similar pattern, with some differences. This process in Step 7 calculates Relevant Levels for Committed Candidates. The basic methodology is as follows: • Form a candidate fleet comprising all Committed Candidates (within which the Small Candidates are further grouped by "Candidate Type", and treated as a single Candidate until Step 7.5) (Steps 7.1 and 7.2). • Call the subroutine in Part D to calculate the ELCC of this fleet of Committed Candidates (Step 7.3). • Then, call the subroutine in Part E to distribute this ELCC (the **"Committed Fleet ELCC"**) between the members of the fleet of Committed Candidates (Step 7.4). • For Standalone Candidates, the value determined under Step 7.4 is the Candidate's Relevant Level (Step 7.5(a)). • For Small Candidates, there is a further apportionment in which the value assigned to the particular group of Small Candidates in Step 7.4 is divided between the individual Small Candidate in proportion to the Facility Average Performance Levels which were determined for each Candidate in Step 6.

7.1. Allocate the Committed Small Candidates to one or more groups so that each of those groups contains all the Committed Candidates of a specific Candidate Type. For the purposes of Steps 7.3 to 7.4, and the subroutines called by those steps, treat each such group as though it was a single Committed Candidate, with a Historical Output equal to the aggregated Historical Outputs of all members of that group.

7.2. The fleet of Committed Candidates comprises:

(a) each Standalone Committed Candidate; and

(b) each group of Committed Small Candidates being treated as a single Candidate under Step 7.1.

7.3. Determine the Committed Fleet ELCC for the Reference Period, by applying the subroutine in Part D using the following inputs:

(a) for "Candidate Group" use the fleet of Committed Candidates determined under Step 7.2; and

(b) for "Baseline Demand Profile" use the Scaled Demand Profile.

7.4. Allocate the Committed Fleet ELCC between the Candidates identified in Step 7.2, by applying the subroutine in Part E using the following inputs:

(a) for "Fleet ELCC" use the Committed Fleet ELCC determined in Step 7.3;

(b) for "Recipient Fleet" use the fleet of Committed Candidates identified in Step 7.2; and

(c) for "Pre-Fleet Demand Profile" use the Scaled Demand Profile.

7.5. For each Recipient allocated ELCC under Step 7.4:

(a) If the Recipient is a Standalone Candidate, then the Relevant Level for that Candidate is the Recipient ELCC determined for the Candidate in Step 7.4.

(b) If the Recipient is a group of Committed Small Candidates being treated as a single Candidate under Step 7.1:

i. Determine the Relevant Level Scaling Factor for the group of Committed Small Candidates as:

$$\text{RL\_Scaling\_Factor} = \frac{\text{Recipient\_ELCC}}{\sum_{c \in \text{Group}} \text{FAPL}(c)}$$

where:

1. Recipient_ELCC is the Recipient ELCC allocated to the group in Step 7.4;

2. $c \in$ Group denotes all Candidates in the group; and

3. FAPL(c) is the Facility Average Performance Level for Candidate c determined in Step 6.3.

ii. Determine the Relevant Level for each Candidate c in the group as:

$$\text{Relevant\_Level}(c) = \max(0, \text{FAPL}(c) \times \text{RL\_Scaling\_Factor})$$

where:

1. FAPL(c) is the Facility Average Performance Level of Candidate c; and

2. RL_Scaling_Factor is the Relevant Level Scaling Factor for the group determined in Step 7.5(b)(i).

Step 8: Determine Relevant Levels for Proposed Candidates

Step 8 Overview

Step 8 is used to calculate Relevant Levels for Proposed Candidates. It applies the same methodology as Step 7, with the following changes:

- The Small Proposed Candidates are dealt with first, because there may not be enough Small Proposed Candidates of a given type to support the calculation of a meaningful group ELCC value (Step 8.1). As a result, Step 8 does not require the final re-distribution between Small Candidates which appears in Step 7.5(b).
- The ELCC for the fleet of Proposed Candidates measures the incremental contribution of the Proposed Candidates, after the Committed Candidate' contribution is taken into account.

8.1. Determine the Relevant Level for each Proposed Candidate c that is a Small Candidate:

Relevant_Level(c) = max(0, FAPL(c) × RL_Scaling_Factor(g))

where:

(a) FAPL(c) is the Facility Average Performance Level of Proposed Candidate c determined in Step 6.3;

(b) g denotes the group of Candidates specified in Step 7.1 that contains Committed Candidates with the same Candidate Type as Proposed Candidate c; and

(c) RL_Scaling_Factor(g) is the Relevant Level Scaling Factor determined for group g in Step 7.5(b)(i).

8.2. If no Proposed Candidates are Standalone Candidates then:

(a) Set the Committed and Proposed Fleet ELCC for the Reference Period to the Committed Fleet ELCC determined in Step 7.3; and

(b) proceed to Step 9.

8.3. Steps 8.4 to 8.7 apply if there is a fleet comprising one or more Proposed Standalone Candidates.

8.4. Determine the Committed and Proposed Fleet ELCC for the Reference Period, by applying the subroutine in Part D using the following inputs:

(a) for "Candidate Group" use a group consisting of:

i. all Committed Candidates; and

ii. all Proposed Standalone Candidates; and

(b) for "Baseline Demand Profile" use the Scaled Demand Profile;

8.5. Determine the Proposed Fleet ELCC for the Reference Period as:

Proposed_Fleet_ELCC = C&P_Fleet_ELCC - Committed_Fleet_ELCC

where:

(a) C&P_Fleet_ELCC is the Committed and Proposed Fleet ELCC for the Reference Period determined in Step 8.4; and

(b) Committed_Fleet_ELCC is the Committed Fleet ELCC for the Reference Period determined in Step 7.3.

8.6. Allocate the Proposed Fleet ELCC between the Candidates identified in Step 8.3, by applying the subroutine in Part E using the following inputs:

(a) for "Fleet ELCC" use the Proposed Fleet ELCC determined in Step 8.5;

(b) for "Recipient Fleet" use the fleet of Candidates identified in Step 8.3; and

(c) for “Pre-Fleet Demand Profile” use the Ex-Committed Demand Profile determined in Step 5.1.

8.7. The Relevant Level of each Proposed Standalone Candidate is the Recipient ELCC determined in Step 8.6 for the Candidate.

Step 9: Determine Relevant Levels for Early CRC Candidates

Step 9 Overview

Step 9 is used to calculate Relevant Levels for Early CRC Candidates. It applies the same methodology as Step 8, with the following changes:

- The ELCC for the fleet of Early CRC Candidates measures the incremental contribution of the Early CRC Candidates, after the combined contribution of Committed and Proposed Candidates is taken into account.
- To facilitate this, Step 9 includes an additional step, namely determining a demand profile adjusted for the contribution of Proposed Candidates, i.e. assuming the Proposed Candidates are constructed as proposed (**“Ex-Committed and Proposed Demand Profile”**) (Step 9.6). This is then used in Step 9.7, to assess the Early CRC Candidates’ contribution.

9.1. Determine the Relevant Level for each Early CRC Small Candidate as:

Relevant_Level(c) = max(0, FAPL(c) × RL_Scaling_Factor(g))

where:

(a) FAPL(c) is the Facility Average Performance Level of Early CRC Candidate c determined in Step 6.3;

(b) g denotes the group of Candidates specified in Step 7.1 that contains Committed Candidates with the same Candidate Type as Early CRC Candidate c; and

(c) RL_Scaling_Factor(g) is the Relevant Level Scaling Factor determined for group g in Step 7.5(b)(i).

9.2. If there are no Early CRC Standalone Candidates:

(a) Set the Committed and Proposed and Early CRC Fleet ELCC for the Reference Period to the Committed and Proposed Fleet ELCC determined in Step 8.2(a) or Step 8.4 (as applicable); and

(b) proceed to Step 10.

9.3. Steps 9.4 to 9.8 apply if there is a fleet comprising one or more Early CRC Standalone Candidates.

9.4. Determine the Committed and Proposed and Early CRC Fleet ELCC for the Reference Period, by applying the subroutine in Part D using the following inputs:

(a) for “Candidate Group” use a group consisting of:

i. all Committed Candidates;

ii. any Proposed Standalone Candidates; and

iii. all Early CRC Standalone Candidates; and

(b) for “Baseline Demand Profile” use the Scaled Demand Profile;

9.5. Determine the Early CRC Fleet ELCC for the Reference Period as:

Early_CRC_Fleet_ELCC = C&P&E_Fleet_ELCC - C&P_Fleet_ELCC

where:

(a) C&P&E_Fleet_ELCC is the Committed and Proposed and Early CRC Fleet ELCC for the Reference Period determined in Step 9.4; and

(b) C&P_Fleet_ELCC is the Committed and Proposed Fleet ELCC for the Reference Period determined in Step 8.2(a) or Step 8.4 (as applicable).

9.6. Determine the Ex-Committed and Proposed Demand Profile for the Reference Period so that for each Trading Interval t in the Reference Period:

$$\text{Ex-C\&P\_Demand}(t) = \text{Ex-Committed\_Demand}(t) - \sum_{c \in \text{Standalone P}} \text{Historical\_Output}(c,t)$$

where:

(a) Ex-C&P_Demand(t) is the system demand (in MW) specified for Trading Interval t in the Ex-Committed and Proposed Demand Profile;

(b) Ex-Committed_Demand(t) is the system demand (in MW) specified for Trading Interval t in the Ex-Committed Demand Profile determined in Step 5.1;

(c) c ∈ Standalone P denotes all Proposed Standalone Candidates; and

(d) Historical_Output(c,t) is the Historical Output value determined for Candidate c and Trading Interval t in Step 2.7.

9.7. Allocate the Early CRC Fleet ELCC between the Candidates identified in Step 9.3, by applying the subroutine in Part E using the following inputs:

(a) for “Fleet ELCC” use Early CRC Fleet ELCC determined in Step 9.5;

(b) for “Recipient Fleet” use the fleet of Candidates identified in Step 9.3; and

(c) for “Pre-Fleet Demand Profile” use the Ex-Committed and Proposed Demand Profile determined in Step 9.6.

9.8. The Relevant Level of each Early CRC Standalone Candidate is the Recipient ELCC determined in Step 9.7 for the Candidate.

Step 10: Determine Relevant Levels for Conditional CRC Candidates

> **Step 10 Overview**
>
> Step 10 is used to calculate Relevant Levels for Conditional CRC Candidates. It applies the same methodology as Step 9.
>
> The ELCC for the fleet of Conditional CRC Candidates measures the incremental contribution of the Conditional CRC Candidates, after the combined contribution of Committed, Proposed and Early CRC Candidates is taken into account. This is reflected in Step 10.6.

10.1. Determine the Relevant Level for each Conditional CRC Small Candidate c:

Relevant_Level(c) = max(0, FAPL(c) × RL_Scaling_Factor(g))

where:

(a) FAPL(c) is the Facility Average Performance Level of Conditional CRC Candidate c determined in Step 6.3;

(b) g denotes the group of Candidates specified in Step 7.1 that contains Committed Candidates with the same Candidate Type as Conditional CRC Candidate c; and

(c) RL_Scaling_Factor(g) is the Relevant Level Scaling Factor determined for group g in Step 7.5(b)(i).

10.2. If there are no Conditional CRC Standalone Candidates then proceed to Step 11.

10.3. Steps 10.4 to 10.8 apply if there is a fleet comprising one or more Conditional CRC Standalone Candidates.

10.4. Determine the Committed and Proposed and Early CRC and Conditional CRC Fleet ELCC for the Reference Period, by applying the subroutine in Part D using the following inputs:

(a) for "Candidate Group" use a group consisting of:

i. all Committed Candidates;

ii. any Proposed Standalone Candidates;

iii. any Early CRC Standalone Candidates; and

iv. all Conditional CRC Standalone Candidates; and

(b) for "Baseline Demand Profile" use the Scaled Demand Profile;

10.5. Determine the Conditional CRC Fleet ELCC for the Reference Period as:

Conditional_CRC_Fleet_ELCC = C&P&E&Co_Fleet_ELCC - C&P&E_Fleet_ELCC

where:

(a) C&P&E&Co_Fleet_ELCC is the Committed and Proposed and Early CRC and Conditional CRC Fleet ELCC for the Reference Period determined in Step 10.4; and

(b) C&P&E_Fleet_ELCC is the Committed and Proposed and Early CRC Fleet ELCC for the Reference Period determined in Step 9.2(a) or Step 9.4 (as applicable).

10.6. Determine the Ex-Committed and Proposed and Early CRC Demand Profile for the Reference Period so that for each Trading Interval t in the Reference Period:

$$\text{Ex-C\&P\&E\_Demand}(t) = \text{Ex-C\&P\_Demand}(t) - \sum_{c \in \text{Standalone E}} \text{Historical\_Output}(c,t)$$

where:

(a) Ex-C&P&E_Demand(t) is the system demand (in MW) specified for Trading Interval t in the Ex-Committed and Proposed and Early CRC Demand Profile;

(b) Ex-C&P_Demand(t) is the system demand (in MW) specified for Trading Interval t in the Ex-Committed and Proposed Demand Profile determined in Step 9.6;

(c) c ∈ Standalone E denotes all Early CRC Standalone Candidates; and

(d) Historical_Output(c,t) is the Historical Output value determined for Candidate c and Trading Interval t in Step 2.7.

10.7. Allocate the Conditional CRC Fleet ELCC between the Candidates identified in Step 10.3, by applying the subroutine in Part E using the following inputs:

(a) for "Fleet ELCC" use the Conditional CRC Fleet ELCC determined in Step 10.5;

(b) for "Recipient Fleet" use the fleet of Candidates identified in Step 10.3; and

(c) for "Pre-Fleet Demand Profile" use the Ex-Committed and Proposed and Early CRC Demand Profile determined in Step 10.6.

10.8. The Relevant Level of each Conditional CRC Standalone Candidate is the Recipient ELCC determined in Step 10.7 for the Candidate.

Step 11: Publish Inputs and Results on the WEM Website

Step 11 Overview
Step 11 requires AEMO to publish the details of the Relevant Level Method calculations.

11.1. Publish on the WEM Website within three Business Days after the date specified in clause 4.1.15A (as modified or extended) for the Current Reserve Capacity Cycle:

(a) the Trading Interval Group determined in Step 3.6 for each Trading Interval in the Reference Period;

(b) the Capacity Outage Probability Table determined in Step 3.7 for each Trading Interval Group;

(c) the Observed Demand for the Reference Period determined in Step 4.1;

(d) the estimated historical and future levels of behind-the-meter photovoltaic capacity in the SWIS that AEMO used to determine the DER Adjusted Demand Profile for the Reference Period in Step 4.2;

(e) the Committed Fleet ELCC determined in Step 7.3;

(f) the Proposed Fleet ELCC determined in Step 8.5 (if applicable);

(g) the Early CRC Fleet ELCC determined in Step 9.5 (if applicable);

(h) the Conditional CRC Fleet ELCC determined in Step 10.5 (if applicable);

(i) for each Candidate:

i. whether the Candidate is a Committed Candidate, a Proposed Candidate, an Early CRC Candidate or a Conditional CRC Candidate;

ii. the Candidate Type assigned in Step 3.1; and

iii. the Historical Output values determined in Step 2.7 for each Trading Interval in the Reference Period;

(j) for each Candidate that was allocated a Recipient ELCC in accordance with Part E:

i. the First-In ELCC determined in Step E.3(b);

ii. the Last-In ELCC determined in Step E.3(c);

iii. the Recipient Interactive Effect Share determined in Step E.4; and

iv. the Recipient ELCC determined in Step E.6;

(k) the X Trading Intervals identified in Step 6.1;

(l) the X Trading Intervals identified in Step 6.2; and

(m) the Relevant Level Scaling Factor determined for each group of Committed Small Candidates in Step 7.5(b)(i).

Part C: Subroutine to calculate Loss of Load Expectation for a given Demand Profile

Part C Overview

This subroutine is called multiple times from the subroutine in Part D.

It calculates the **"Loss of Load Expectation"** for a given system demand profile, as follows:

- First, for every Trading Interval in the Reference Period, determine the probability of a loss of load in that Trading Interval, by determining the probability that the output of the non-intermittent fleet would be insufficient to meet the demand in that Trading Interval, as shown in the selected demand profile (Step C.1). This is done by reading from the relevant COPT, the cumulative probability that the MW of Forced Outages would exceed the 'headroom' which exists between the theoretical maximum output of the non-intermittent fleet at the time (**"NIF_Max(t)"**) and the demand as shown in the relevant profile (**"D(t)"**). This cumulative probability (**"P(NIF_Max(t)–D(t))"**)* gives an estimate of the probability of a supply shortfall in that Trading Interval, due to the impact of Forced Outages on the non-intermittent fleet.

* In other words, calculate the MW value of NIF_Max(t) minus D(t), to yield the 'headroom' which should be available in that Trading Interval, and then look up this MW value in the COPT to find the cumulative probability that this much or more of the non-intermittent fleet will be unavailable.

The COPT is not used if the demand in a Trading Interval exceeds the theoretical maximum capacity of the non-intermittent fleet. For these Trading Intervals a loss of load is certain so the loss of load probability is equal to 1.

- Then, sum these probability values across all Trading Intervals in the Reference Period. The total value is the Loss of Load Expectation for that system demand profile, measured in Trading Intervals.

This Part C subroutine requires the following inputs:

(a) the system demand profile to be used in the determination (**"Demand Profile"**).

C.1. Determine the loss of load probability for each Trading Interval t in the Reference Period as:

LOLP(t) = P(NIF_Max(t) – D(t))

where:

(a) NIF_Max(t) is the value of NIF_Max determined in Step 3.7(b) for the Trading Interval Group to which Trading Interval t was assigned in Step 3.6;

(b) D(t) is the system demand (in MW) that is specified for Trading Interval t in the relevant Demand Profile; and

(c) P(NIF_Max(t) – D(t)) is:

i. 1, if NIF_Max(t) is less than D(t); and

ii. otherwise, the probability that at least NIF_Max(t) – D(t) MW of the Non-Intermittent Facility capacity required to be available in Trading Interval t will be unavailable due to a Forced Outage, determined from the Capacity Outage Probability Table developed for the relevant Trading Interval Group in Step 3.7.

C.2. Determine the loss of load expectation in the SWIS over the Reference Period for the given Demand Profile as:

$$\text{LOLE} = \sum_{t \in RP} \text{LOLP}(t)$$

where:

(a) t ∈ RP denotes all Trading Intervals in the Reference Period; and

(b) LOLP(t) is the loss of load probability for Trading Interval t determined in Step C.1.

Part D: Subroutine to calculate Effective Load Carrying Capability of a Candidate or Candidate Fleet for a given Baseline Demand Profile

Part D overview

This subroutine is called multiple times in Steps 7 to 10.

It operates to determine the **"Effective Load Carrying Capability"** (**"ELCC"**) of a given group of Candidates (**"Candidate Group"** – noting that when this subroutine is called from Part E the group contains a single member), for a given level of system demand (**"Baseline Demand Profile"**).

The subroutine does this by iteratively calling the Loss of Load Expectation (**"LOLE"**) subroutine in Part C, as follows:

- First, determine the LOLE if the system demand reported in the Baseline Demand Profile was being met only by the Non-Intermittent Facilities which have been factored into the COPTs in Step 3 – i.e. the Non-Intermittent Facilities for which Certified Reserve Capacity is being assessed for the current Reserve Capacity Cycle (Step D.1).
- Then, calculate a new hypothetical system load profile ("**Net Demand Profile"**), being the Baseline Demand Profile minus the combined historical output of the group of Candidates being assessed on this run of the subroutine (Step D.2), and calculate the LOLE again (Step D.3). Because this net demand is less than the baseline demand, this will normally produce a smaller LOLE, i.e. predicting a smaller number of Trading Intervals having supply shortfalls.
- Then, iterate the LOLE calculation (Step D.5), increasing the demand profile in every Trading Interval by an increment of 0.1 MW in each iteration (Step D.4), until it produces a LOLE result which equals the base LOLE calculated in the first step (Step D.6).
- The amount by which the net demand was incremented, is the relevant group's ELCC. The ELCC is an estimate of how much additional demand the system can cover after the addition of the group while not exceeding the original LOLE for the Baseline Demand Profile.

This Part D subroutine requires the following inputs:

(a) a Candidate Group or Candidate for which an ELCC is to be determined (**"Candidate Group"**); and

(b) the system demand profile to be used in the determination (**"Baseline Demand Profile"**).

D.1. Determine the loss of load expectation over the Reference Period for the relevant Baseline Demand Profile, by applying the subroutine in Part C using the following input:

(a) for "Demand Profile" use the Baseline Demand Profile.

D.2. Determine the Net Demand Profile for the Reference Period so that for each Trading Interval t in the Reference Period:

$$\text{NSD(t)} = \text{BSD(t)} - \sum_{c \in G} \text{Historical\_Output(c,t)}$$

where:

(a) NSD(t) is the system demand (in MW) specified for Trading Interval t in the Net Demand Profile;

(b) BSD(t) is the system demand (in MW) specified for Trading Interval t in the Baseline Demand Profile;

(c) $c \in G$ denotes all Candidates in the given Candidate Group; and

(d) Historical_Output(c,t) is the Historical Output value determined for Candidate c and Trading Interval t in Step 2.7.

D.3. Determine the loss of load expectation over the Reference Period for the Net Demand Profile by applying the subroutine in Part C using the following input:

(a) for "Demand Profile" use the Net Demand Profile calculated under Step D.2.

D.4. Increment the system demand specified for each Trading Interval in the Net Demand Profile by 0.1 MW.

D.5. Determine the loss of load expectation over the Reference Period for the amended Net Demand Profile by applying the subroutine in Part C using the following input:

(a) for "Demand Profile" use the most-recently-incremented profile determined under Step D.4.

D.6. Repeat Steps D.4 and D.5 until the loss of load expectation determined in Step D.5 is equal to or closest to the loss of load expectation determined in Step D.1 for the Baseline Demand Profile.

D.7. The effective load carrying capability ("**ELCC**") of the Candidate Group for the Reference Period (assuming the given Baseline Demand Profile) is the total MW quantity by which the system demand values in the Net Demand Profile needed to be increased to meet the criterion specified in Step D.6.

Part E: Subroutine to allocate Fleet-Level Effective Load Carrying Capability to Candidates

Part E overview

This subroutine is called from within each of Steps 7, 8, 9 and 10, and is used once the Effective Load Carrying Capability of a given fleet of Candidates (**"Fleet ELCC"**) has been determined, to apportion that value between individual members of the fleet, known as **"Recipients"** (including, in some cases, groups of Small Candidates being treated as a single Candidate under Step 7.1(a)).

The subroutine does this as follows:

- First, take as an input the system demand profile against which the fleet's contribution is to be assessed (**"Pre-Fleet Demand Profile"**) (input (a)).
  - When using this subroutine to apportion ELCC between members of the **Committed fleet**, this will simply be the scaled "System Demand Profile" (see Step 7.4(c)).
  - When apportioning ELCC between members of the **Proposed fleet**, the Pre-Fleet Demand Profile will be the "Ex-Committed Demand Profile" (see Step 8.6(c)), because the

Proposed fleet is assessed assuming that the Committed Candidates were providing their Historical Output.

  - When apportioning ELCC between members of the **Early CRC fleet**, the Pre-Fleet Demand Profile will be the "Ex-Committed and Proposed Demand Profile" (see Step 9.6(c)), because the Early CRC fleet is assessed assuming that the Committed and Proposed Candidates were providing their Historical Output.
  - When apportioning ELCC between members of the **Conditional CRC fleet**, the Pre-Fleet Demand Profile will be the "Ex-Committed and Proposed and Early CRC Demand Profile" (see Step 10.6(c)), because the Conditional CRC fleet is assessed assuming that all the other Candidates were providing their Historical Output.
- Next, deduct the Historical Output of the relevant group of candidates from the Pre-Fleet Demand Profile, to determine the **"Post-Fleet Demand Profile"** (Step E.1). This profile represents the scenario where all the Recipients were providing their Historical Output.
- Then, for each Recipient, calculate:
  - its **"Last-In Demand Profile"** (Step E.2(a)), by adding the Historical Output of the Recipient to the Post-Fleet Demand Profile – this profile represents the scenario where all the Recipients except this one were providing their Historical Output;
  - its **"First-In ELCC"**, by calling the subroutine in Part D, using the Pre-Fleet Demand Profile (Step E.2(b)) – this measures the Recipient's ELCC assuming it was the sole contributor from this fleet;
  - its **"Last-In ELCC"**, by calling the subroutine in Part D, using the Recipient's Last-In Demand Profile (Step E.2(c)) – this measures the Recipient's ELCC assuming that all the other Recipients were already contributing; and
  - its **"Recipient Delta"**, which is the difference between its First-In ELCC and its Last-In ELCC (Step E.2(d)) – this shows how the rest of the fleet's contribution affects this Recipient's contribution.
- Then, for the fleet, determine the **"Fleet Interactive Effect"**, being the Fleet ELCC minus the sum of each Recipient's Last-In ELCCs (Step E.3). This measures the extent to which the whole is greater (or weaker) than the sum of the parts.
- Then, allocate each Recipient a share of the Fleet Interactive Effect (its **"Recipient Interactive Effect Share"**) based on its Recipient Delta (Step E.4).
- Finally, determine each Recipient's **"Recipient ELCC"** (Step E.5), which is its Last-In ELCC (reflecting its marginal contribution) plus its Recipient Interactive Effect Share (reflecting its contribution to the Fleet Interactive Effect).

This Part E subroutine requires the following inputs:

(a) the fleet-level effective load carrying capability quantity to be allocated (**"Fleet ELCC"**);

(b) the Candidates to which the Fleet ELCC is to be allocated (collectively the **"Recipient Fleet"**, and each a **"Recipient"**); and

(c) the system demand profile for the Reference Period against which the contribution of the Recipients is to be assessed (**"Pre-Fleet Demand Profile"**).

E.1. Determine the Post-Fleet Demand Profile for the Reference Period so that for each Trading Interval t in the Reference Period:

$$\text{Post-Fleet}(t) = \text{Pre-Fleet}(t) - \sum_{r \in RF} \text{Historical\_Output}(r,t)$$

where:

(a) Post-Fleet(t) is the system demand (in MW) specified for Trading Interval t in the Post-Fleet Demand Profile;

(b) Pre-Fleet(t) is the demand (in MW) specified for Trading Interval t in the Pre-Fleet Demand Profile;

(c) r ∈ RF denotes all the Recipients assigned to the Recipient Fleet; and

(d) Historical_Output(r,t) is the Historical Output value determined for Recipient r and Trading Interval t in Step 2.7.

E.2. For each Recipient r determine:

(a) the Last-In Demand Profile for the Reference Period so that for each Trading Interval t in the Reference Period:

Last-In(r,t) = Post-Fleet(t) + Historical_Output(r,t)

where:

i. Last-In(r,t) is the system demand (in MW) specified for Trading Interval t in the Last-In Demand Profile for Recipient r;

ii. Post-Fleet(t) is the system demand (in MW) specified for Trading Interval t in the Post-Fleet Demand Profile determined in Step E.1; and

iii. Historical_Output(r,t) is the Historical Output value determined for Recipient r and Trading Interval t in Step 2.7.

(b) the First-In ELCC, using the subroutine in Part D with:

i. Recipient r as the Candidate Group; and

ii. the Pre-Fleet Demand Profile as the Baseline Demand Profile;

(c) the Last-In ELCC, using the subroutine in Part D with:

i. Recipient r as the Candidate Group; and

ii. the Last-In Demand Profile determined for Recipient r in Step E.2(a) as the Baseline Demand Profile; and

(d) the Recipient Delta as:

Delta(r) = First-In_ELCC(r) – Last-In_ELCC(r)

where:

i. First-In_ELCC(r) is the First-In ELCC value determined for Recipient r in Step E.2(b); and

ii. Last-In_ELCC(r) is the Last-In ELCC value determined for Recipient r in Step E.2(c).

E.3. Determine the Fleet Interactive Effect as:

$$\text{Fleet\_Interactive\_Effect} = \text{Fleet\_ELCC} - \sum_{r \in RF} \text{Last-In\_ELCC}(r)$$

where:

(a) $r \in RF$ denotes all members of the Recipient Fleet; and

(b) Last-In_ELCC(r) is the Last-In ELCC value determined for Recipient r in Step E.2(c).

E.4. For each Recipient r determine the Recipient Interactive Effect Share as:

$$\text{IE\_Share}(r) = \text{Delta}(r) \times \frac{\text{Fleet\_Interactive\_Effect}}{\sum_{r \in RF} \text{Delta}(r)}$$

where:

(a) Fleet_Interactive_Effect is the Fleet Interactive Effect determined in Step E.3;

(b) $r \in RF$ denotes all members of the Recipient Fleet; and

(c) Delta(r) is the Recipient Delta determined for Recipient r in Step E.2(d).

E.5. For each Recipient r, determine the Recipient ELCC:

Recipient_ELCC(r) = Last-In_ELCC(r) + IE_Share(r)

where:

(a) Last-In_ELCC(r) is the Last-In ELCC value determined for Recipient r in Step E.2(c); and

(b) IE_Share(r) is the Recipient Interactive Effect Share determined for Recipient r in Step E.4.

Appendix A. Responses to Submissions Received in the First Submission Period

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
Methodology – historical data as a predictor of 10% POE forecast demand conditions			
1	AEMO	AEMO examined the performance of SWIS wind farms between 2010 and 2020 during Trading Intervals where the air temperature measured at the Perth Airport was at least 38 degrees Celsius. AEMO's observations suggested that: • wind farms located in the northern and eastern regions of the SWIS show a decrease in their average performance level as air temperature increases from 38 degrees to 44 degrees; and • wind farms located in the southern regions of the SWIS do not show a consistent trend of reduction in their average performance level at temperatures greater than 38 degrees. AEMO considers that the observed performance differences were likely due to milder weather conditions in the southern region. AEMO noted that: • maximum temperatures measured at the Badgingarra and Merredin weather stations for peak demand days are generally close to the maximum temperatures at the Perth Airport weather station; • maximum temperatures measured at the Albany Airport weather stations for peak demand days are on average more than 10 degrees lower than the maximum temperatures at the Perth Airport weather station.	Please refer to section 6.1.5 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		AEMO considers that the observed correlation between high air temperatures and lower wind farm output in the northern and eastern regions of the SWIS may be associated with three factors: • lower wind speed correlated with higher air temperatures; • lower air density driven by higher air temperature; and • power de-rating due to insufficient cooling on main components of wind turbines. AEMO notes that these three factors may reduce the performance of wind farms located in the northern and eastern regions of the SWIS further than their historical output when a 10% POE peak demand event occurs. However, the SWIS has seldom experienced a 10% POE peak demand event. Accordingly, historical wind farm output data may not sufficiently capture the potentially reduced available capacity of the wind farms during periods with the highest loss of load probability, when a 10% POE peak demand event occurs. In this scenario, AEMO considers that the proposed RLM may result in an overestimation of the wind farms' capacity values.	
2	AEMO	For the period 6-9 January 2021, Perth experienced four days with maximum daily temperature exceeding 36 degrees and the highest was 41.5 degrees on 8 January 2021. The maximum demand on 8 January 2021 reached 3,788 MW, which was the seventh highest market load day in the history of the WEM. During the Trading Interval in which maximum demand was recorded, a very	Please refer to sections 6.1.4 and 6.1.5 of this report. The Rule Change Panel notes AEMO has clarified that, during the relevant peak Trading Interval (6:00 PM to 6:30 PM) the Generator Interim Access (**GIA**) Tool constrained about 70 MW of output of the GIA Facilities, indicating that about 206 MW of

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		tight reserve margin was achieved partly due to only 136 MW of generation from Intermittent Generators being available out of the 257.7 MW of Capacity Credits assigned to Intermittent Generators (with a total maximum capacity of 1,185 MW).	intermittent generation capacity was available in the Trading Interval.
3	Alinta Energy	According to the Rule Change Proposal, AEMO and RCP Support raised concerns that the proposed RLM would not reflect Intermittent Generators' available capacity during 1 in 10 peak demand periods; and suggested that Intermittent Generators' output be scaled to replicate how Intermittent Generators' output is impacted during these periods. Alinta Energy does not share these concerns, nor support adjusting Intermittent Generators' output in this way for the following reasons (issues 4 to 6 below).	Please refer to section 6.1.5 of this report.
4	Alinta Energy	[Alinta Energy's reasons for not adjusting Intermittent Generators' output to reflect their expected available capacity in 1 in 10 peak demand periods] Firstly, this would require the RLM to incorporate highly fraught and arbitrary forecasts: the RLM would need to predict the conditions where the POE10 forecast is likely to materialise, and then estimate what the output of wind and solar facilities would be, given these conditions. The data presented in the Rule Change Proposal shows that these conditions, and their impact on the output of Intermittent Generators cannot be reliably predicted. Alinta Energy considers that the proposed method is preferable to forecasting a generator's output in POE10	Please refer to section 6.1.5 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		intervals because it does not seek to predict an arbitrary set of circumstances, and then forecast the output of generators under these circumstances. Instead, it recognises that capacity can be required to maintain reliability in a variety of situations, and values Intermittent Generators based on their available capacity during such high system stress periods, using historical data across all Trading Intervals.	
5	Alinta Energy	[Alinta Energy's reasons for not adjusting Intermittent Generators' output to reflect their expected available capacity in 1 in 10 peak demand periods] Another benefit of the proposed RLM compared to AEMO and RCP Support's suggestion is that it would not rely on static assumptions about what the conditions will be in a POE10 scenario. If the RLM was amended to try and predict Intermittent Generators' output based on these assumptions, it could cause errors where peak demand conditions change, and these assumptions become incorrect. This is crucial considering how increasing rooftop solar has, and how emerging DER technologies like batteries and EVs could, significantly alter the periods when the POE10 demand forecast is expected to materialise.	Please refer to section 6.1.5 of this report.
6	Alinta Energy	[Alinta Energy's reasons for not adjusting Intermittent Generators' output to reflect their expected available capacity in 1 in 10 peak demand periods] Finally, Alinta Energy considers that the RLM should be consistent with both components of the Planning Criterion. If the RLM simply attempted to value Intermittent	Please refer to section 6.1.5 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		Generators based on their output in conditions when the POE10 forecast is expected to materialise, then it would ignore their contribution to the second component of the Planning Criterion, which is concerned with how a generator reduces expected unserved energy over a Capacity Year. Alinta Energy considers that the proposed RLM would address both parts of the Planning Criterion because it values Intermittent Generators both on their expected contribution to reliability during high stress, peak demand events, and throughout a Capacity Year.	
Determination of Candidate Facilities and Full Operation Dates			
7	AEMO	Proposed Appendix 9 ((a) and (b)) states: *'This Appendix presents the method for determining the Relevant Level for Facilities ('Candidate Facilities') for which* *(a) Market Participants have applied for certification of Reserve Capacity for a given Reserve Capacity Cycle under section 4.9; and* *(b) the Certified Reserve Capacity is to be assigned using the method in clause 4.11.2(b).'* Some of these Facilities may not have submitted valid applications, therefore will not receive CRC. Including these Facilities in the RL calculation is likely to result in incorrect RL values calculated for other Candidate Facilities. AEMO suggests that, in addition to the two conditions outlined in Appendix 9 (a) and (b), a Facility should also	The Rule Change Panel agrees with AEMO's suggestion and has included the additional condition in clause A1(b) of Appendix 9.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		meet the following condition to be considered as a Candidate Facility: *'the Market Participants' applications for certification include all supporting information required under section 4.10 and are deemed by AEMO to be complete;'.*	
8	AEMO	Part A(a)(i) of proposed Appendix 9 states: *'(a) the full operation date of a Candidate Facility for the Reserve Capacity Cycle ('**Full Operation Date**') is:* *i. the date provided under clause 4.10.1(c)(iii)(7) or revised in accordance with clause 4.27.11A, where at the time the application for certification of Reserve Capacity is made the Facility, or part of the Facility (as applicable) is yet to enter service (excluding a part of a Facility that is an Electric Storage Resource for which Certified Reserve Capacity is not being assessed in accordance with the methodology in this Appendix 9); or'* It appears that adding an ESR component to a Candidate Facility would not change that Candidate Facility's Full Operation Date (**FOD**) under the Proposed RLM. The Candidate Facility's generation may be used to charge the ESR and, most likely will change its generation profile. This impact cannot be accounted for in the RL calculation if the Candidate Facility's FOD is not changed to be in line with the ESR operation date.	The Rule Change Proposal does not seek to change the rules for determining Full Operation Dates for Semi-Scheduled Facilities that are upgraded to add an ESR to an existing Intermittent Generating System. The Rule Change Panel notes that these arrangements were implemented by the Minister in the T2&3 Amending Rules. The Rule Change Panel considers this issue to be outside the scope of the Rule Change Proposal, but has referred AEMO's concerns about the matter to EPWA.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		AEMO encourages the Rule Change Panel to assess the expected impact of adding an ESR component on a Candidate Facility's FOD.	
9	AEMO	Part A(b) of proposed Appendix 9 states: *'(b) a Candidate Facility will be considered to be:* i. *a new Candidate Facility, if the seven-year period identified in Step 1(a) of this Appendix commenced before 8:00 AM on the Full Operation Date for the Facility ('**New Candidate Facility**'); or* ii. *an existing Candidate Facility ('**Existing Candidate Facility**'), otherwise.'* Each Candidate Facility that is a component of an aggregated Facility will be considered as a New Candidate Facility or Existing Candidate Facility based on its FOD. However, it is unclear how to determine the FOD of such a Candidate Facility. Assuming each Candidate Facility that is a component of an aggregated Facility has the same FOD as the aggregated Facility, this FOD could be earlier than, within, or after the relevant seven-year period. Therefore, meter data may be required for the calculation, and this data may not be available for the Candidate Facility. Therefore, each Candidate Facility that is a component of an aggregated Facility should not be considered as either a New Candidate Facility or an Existing Candidate Facility. An independent expert report (**IER**) should always be required.	Please refer to the response to Issue 8 above. The Rule Change Panel also notes that the draft RLM does not use the terms 'New Candidate Facility' and 'Existing Candidate Facility'.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		AEMO suggests amending this step as below: *'(b) a Candidate Facility that <u>is not a component of an aggregate Facility</u> will be considered to be:'.*	
10	AEMO	Part A(e) of proposed Appendix 9 states: *'for the purpose of this Appendix 9, <u>the individual Facilities</u>, other than those that are Electric Storage Resource, within an aggregated Facility <u>t</u>hat is, or to be, registered as a Semi-Scheduled Facility under section 2.30, are to be treated as separate Candidate Facilities and be assigned to the relevant Facility group as per the list above.'* It is not clear how to identify individual Facilities in an aggregated Facility. This is because the components of an aggregated Facility are not registered as individual Facilities. For a new Facility, clause 4.8A.1 of the T2&3 Amending Rules requires AEMO to determine and assign an indicative Facility Class and an indicative Facility Technology Type. The Facility's registered Facility Class may change from its indicative Facility Class. AEMO suggests that this step should provide clear guidance on how to identify individual components of an aggregated Facility to be treated as separate Candidate Facilities. This identification should be based on components' Technology Types. AEMO suggests this step should be revised as: *'for the purpose of this Appendix 9, the individual Facilities, other than those that are Electric Storage*	The Rule Change Panel does not propose to implement the concept of Technology Groups or to require AEMO to identify individual intermittent Facilities within a Semi-Scheduled Facility. Please refer to section 6.1.8 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		Resource, within an aggregated Facility that is, or ~~to~~ <u>may</u> be, registered as a Semi-Scheduled Facility under section 2.30, are to be treated as separate Candidate Facilities and be assigned to the relevant Facility group as per the list above.'	
11	Synergy	Synergy understands that the proposed RLM is intended to be processed using proposed facilities which have submitted expressions of interest (**EOI**) under the RCM and does not support this approach for the following reasons: i. proposed facilities are only accepted if the Reserve Capacity Target (**RCT**) is not reached. By assessing the quantity of existing Capacity Credits, understanding of impending retirements and knowledge of committed facilities, it is possible to reasonably estimate whether or not the RCT can be met without the inclusion of proposed facilities. Given that proposed facilities are only accepted if the RCT is not met, Synergy considers it unnecessary to include these facilities in the determination of RLM if they are deemed to be unrequired; ii. proposed facilities which have submitted an EOI differ from committed facilities in that they are able to withdraw participation and certification is not guaranteed; iii. withdrawal from the certification process negatively impacts existing and committed facilities by:	Please refer to section 6.1.10 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		a. dampening Capacity Credits allocated, as illustrated under Appendix 4 of the Rule Change Proposal; and b. creating long term, and compounded, adverse effects on the NAQ allocation (and Capacity Credit outcomes) to the financial detriment of the Market Participant; and iv. this approach increases the uncertainty of Capacity Credit allocation for committed facilities. Synergy considers it inequitable to penalise committed and existing facilities by allocating a lower CRC due to proposed facilities that are not required. Synergy therefore suggests the proposed RLM is run based on existing (that are not due to retire) and committed facilities that have applied for Capacity Credits via the Reserve Capacity certification process.	
Determination of Candidate Facility output for ELCC calculations			
12	AEMO	Part A(f) of proposed Appendix 9 states: *'the available capacity of a Candidate Facility for a Trading Interval is the amount of capacity available to be sent out (in MW) <u>at the end of the Trading Interval and</u>, for clarity, is not on <u>Planned Outage or Forced Outage</u> ('**Available Capacity**')'.* • The requirement that Available Capacity is the amount of capacity available to be sent out at the end of the Trading Interval is not consistent with Meter Data Submissions used for the RL calculation, which	The Rule Change Panel agrees with AEMO that the sent out MW level at the end of each Trading Interval is not an appropriate measure in this context. More broadly, the Rule Change Panel does not support replacing the term 'sent out energy' with the term 'Available Capacity' because the latter term is used for a different purpose in the WEM Rules and would be open to misinterpretation if it was used in Appendix 9, as proposed by the ERA.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		measure an average sent out capacity for each Trading Interval. • Planned Outage and Forced Outage are the rule defined terms relating to whether AEMO's approval for an outage to occur has been given or not. The planned and forced outages referred to here should have general meanings applicable to both new and existing Candidate Facilities. Therefore, the rule defined terms Planned Outage and Forced Outage should not be used. AEMO suggests the Rule Change Panel should review and consider revising this step as below: *'the available capacity of a Candidate Facility for a Trading Interval is the average amount of capacity available to be sent out (in MW) ~~at the end of~~ over the Trading Interval and, for clarity, is not on ~~Planned Outage or Forced Outage~~ planned outage or forced outage ('**Available Capacity**')'.*	The Part A(f) provision has been removed in the draft RLM.
Determination of residual demand and net demand for ELCC calculations			
13	AEMO	The Proposed RLM scales the observed historical demand to the expected 10% POE peak demand and accounts for the uptake of DER, such as rooftop solar photovoltaic. The ERA concluded that using scaled demand can reduce bias in the estimate of the capacity value of wind farms due to the relatively low level of observed demand in the SWIS. However, the Proposed RLM still uses the historical output of wind farms, which may not accurately represent their	Please refer to section 6.1.5 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		performance in temperature conditions associated with a 10% POE peak demand. AEMO notes that scaling the observed demand to the forecast 10% POE peak demand without consistently adjusting the historical output of windfarms may still overestimate the wind farms' capacity values. During a peak demand day, air temperature is likely to reach a maximum during the late afternoon and remain extremely high into the evening peak period. For example, the peak demand for the 2015-16 Capacity Year occurred on 8 February 2016 during the Trading Interval occurring from 17:30 to 18:00 when the air temperature was 41°C. The maximum temperature of 42.6°C was recorded during the Trading Interval during 15:00 to 15:30 on the day.	
14	AEMO	Step 7(d)(ii) of proposed Appendix 9 states: *'For each Electric Storage Resource Facility fs, $AC\_ESR(fs)$ (in MW):* *(ii) is equal to zero during a Trading Interval overlapping with the Electric Storage Resource Obligation Intervals, and subsequent Trading Intervals in that Trading Day, when <u>the value of parameter p</u> is less than the expected Forced Outage rate of the Facility'* It is not clear why parameter p can be used to reasonably determine whether an ESR is on a Forced Outage during the Electric Storage Resource Obligation Intervals. AEMO encourages the Rule Change Panel to explain how the parameter p can be used to determine whether an ESR	The Rule Change Panel's draft decision is to: • account for ESRs that are part or all of a Scheduled Facility or Semi-Scheduled Facility through a COPT; and • account for ESRs that are Non-Scheduled Facilities but are not certified using the RLM by reducing the system demand, but without application of parameter p. Please refer to section 6.1.9 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		is on a Forced Outage during the Electric Storage Resource Obligation Intervals.	
15	AEMO	Step 7(e) of proposed Appendix 9 states: *'the part of Scaled Demand to be covered by Facilities other than Candidate Facilities ('Residual Demand') for each Trading Interval in the period identified in Step 1(a):* $$Scaled\ Demand - 2 \times \sum_{c} CF\_Generation(c)$$ *where the expression* $\sum_c CF\_Generation(c)$ *represents the sum of* $CF\_Generation(c)$ *calculated in Step 7(c) across all Facility groups* c*.'* The Scaled Demand does not account for Candidate Facilities' curtailed generation estimated under Step 4 of Appendix 9, while the calculation of Residual Demand accounts for this curtailed generation. This may result in an inaccurate selection of the highest Residual Demand Trading Intervals, particularly where there is a large amount of curtailed generation. AEMO encourages the RCP to review this and exclude Candidate Facilities' curtailed generation estimated under Step 4 of Appendix 9 from the calculation of Residual Demand under Step 7(e) of Appendix 9 if required.	The Rule Change Panel does not agree with AEMO's suggested change, which would result in Fleet ELCC values being calculated using the unadjusted output of the Candidate Facilities. This approach would underestimate the Relevant Levels of Candidate Facilities, which are meant to be calculated on an unconstrained basis.
16	Synergy	Although the Rule Change Proposal aims to improve transparency of the RLM, and does so by removing the K and U parameters, there appears to be limited visibility on the methodology to determine scaled demand.	Please refer to section 6.1.5 of this report. The Rule Change Panel proposes to include a new clause 4.9.11 in the proposed Amending Rules to require AEMO to document in a WEM Procedure how

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		Synergy recommends the derivation of scaled demand, under Appendix 9 Part B Step 7, to be detailed in a WEM Procedure, including the mechanics on how AEMO intends to account for expected generation from DER and the method upon which AEMO estimates behind-the-meter solar photovoltaic generation.	it will determine the system demand profiles that are used in the Relevant Level calculations.
Calculation of the COPT			
17	AEMO	Step 14(a) of proposed Appendix 9 requires AEMO to identify: *(a) all generation systems registered, or to be registered, as Scheduled Facilities, or as part of a Scheduled Facility, or certified for the relevant Reserve Capacity Cycle, and loads registered as Demand Side Programme that will receive Certified Reserve Capacity for Year 3 of the relevant Reserve Capacity Cycle'.* A Semi-Scheduled Facility can comprise of a Non-Intermittent Generating System, such as a diesel generator. AEMO encourages the Rule Change Panel to clarify whether this should be included in the COPT calculation.	The Rule Change Panel has clarified in Step 3.1(a) of the draft RLM that a Non-Intermittent Generating System that is part of a Semi-Scheduled Facility should be included in the COPT calculations, provided that AEMO deems it to be committed and intends to assign it CRC for the current Reserve Capacity Cycle.
18	AEMO	[With respect to the requirement in Step 14(c) of proposed Appendix 9 for AEMO to identify Forced Outage rates for Scheduled Facilities estimated using the relevant WEM Procedure] AEMO needs to be given discretion here to determine not to use any of the three historical Forced Outage rates that were associated with some rare outage	Please refer to section 6.1.9 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		events and were not a reasonable indicator of the future operating performance of the Facility. AEMO suggests that the Rule Change Panel reviews and updates the step to give AEMO discretion to replace any of the three historical Forced Outage rates for a Scheduled Facility where required.	
Initial adjustment of demand to meet a target LOLE			
19	Synergy	The proposed RLM currently allows for four hours of LOLE, as a reflection of the duration requirement set for electronic storage resources under EPWA's proposed changes to the WEM Rules in order to be eligible for reserve capacity certification. Given that this is a new method with no historical data, Synergy suggests the appropriateness of this threshold be reassessed at the next RLM review as modelling becomes more refined.	Please refer to section 6.1.6 of this report.
20	Alinta Energy	Alinta Energy supports the proposal to estimate the capacity value of the fleet based on a target loss of load expectation that aligns with the reliability standards in the WEM. However, Alinta Energy disagrees that the 4-hour Electric Storage Resource Obligation Duration (**ESROD**) indicates that the LOLE target for the WEM is 4 hours in 10 years for the following reasons. Firstly, averting a loss of load event was not the only consideration in selecting the 4-hour ESROD: it was selected because the limited storage duration of storage resources is incompatible with the current 14-hour availability requirement applied to Scheduled Generators.	Please refer to section 6.1.6 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		Compared with the 14-hour requirement, the 4-hour ESROD aims to strike a more appropriate balance between ensuring storage resources contribute to reliability, and allow them enough flexibility, given their limited duration. Secondly, experience in other jurisdictions suggests that the LOLE target should be higher, for example: • Ireland employs a linear de-rating method for accrediting batteries based on their output over 6 hours but has a much higher LOLE target of 80 hours per 10 years. • ERCOT has a much higher LOLE of 24 hours every 10 years, even though it has a more conservative static reserve margin of 13.75% – almost double the WEM's 7.6% margin.	
21	Alinta Energy	Alinta Energy considers that the 14-hour peak Trading Intervals, used to determine the fuel requirement for Scheduled Generators is a more appropriate indicator of the WEM's LOLE target. Unlike the 4-hour ESROD, the 14-hour fuel requirement was selected to maintain reliability by obliging generators to have enough fuel to remain available for the peak Trading Intervals; and was not designed to accommodate the limited duration of storage capacity. Additionally, it better aligns with the LOLE targets and reserve margins used in the other jurisdictions examined.	Please refer to section 6.1.6 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
Determination of fleet ELCC – use of median of seven yearly values vs a single seven-year value			
22	AEMO	Using the median of seven yearly RL values indicates that the probability of the capacity of the fleet of IGs expected to be available to meet a 10% POE peak demand event being at least equal to the median yearly RL value is 50%. AEMO notes that using this median RL value to set the capacity value of the fleet of IGs may not provide adequate certainty of the estimated fleet's capacity value. This is in comparison to AEMO's evaluation of the expected available capacity of Scheduled Facilities (**SF**) and Demand Side Programmes (**DSP**) for the purpose of assigning CRC. • Under clause 4.11.1(h), AEMO may decide not to assign any CRC or to assign a lesser quantity of CRC to a SF if the SF's historical Forced Outage rate is greater than the Outage rate limit of 10% outlined in clause 4.11.1D. This means that the probability of a certified SF being able to deliver the expected available capacity should not be less than 90%. • AEMO assesses the amount of capacity likely to be available from a DSP based on the DSP's Relevant Demand level as determined under clause 4.26.2CA. The Relevant Demand is capped for a DSP at the tenth lowest metered consumption value of the 200 metered consumption values of the DSP's Associated Loads identified for the 200 Calendar Hours with the highest Total Sent Out Generation. This indicates that the probability of a certified DSP having a consumption	Please refer to section 6.1.7 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		level at least equal to its Relevant Demand should not be less than 95% over the period of 200 hours. Using the median of seven yearly RL values would result in a higher risk of over-estimating the available capacity that can be delivered by the fleet of IGs to meet a 10% POE peak demand event.	
23	AEMO	In light of the challenges associated with applying an adjustment to wind farms' historical output, AEMO suggests that a practical approach to amending the Proposed RLM is to use the average of the sixth and seventh lowest yearly fleet RL values, rather than the median yearly RL result to determine the capacity value of the fleet of IGs. This average RL value is approximately at the tenth percentile of the seven yearly RL values. AEMO considers the use of the average of the sixth and seventh lowest yearly fleet RL values could improve certainty of the fleet of IGs delivering the estimated capacity value during a 10% POE peak demand event and may mitigate the risk of over-estimating the capacity value of the fleet of IGs due to the lack of performance data.	Please refer to section 6.1.7 of this report.
24	Synergy	Appendix 9, Part B, step 9 outlines the calculation of relevant level for the fleet of candidate facilities and facility groups. In accordance with step 9(d), the relevant level is calculated by taking the lower of: i. the median of the relevant level for each 12-month period in the preceding seven years; and	Please refer to section 6.1.7 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		ii. the relevant level based on the entire seven-year period. Synergy considers the use of the minimum of the two sample results unreasonable as it inadvertently, with no apparent justification, underestimates the fleet's capacity value. By extending the sample period from five to seven years, the impact from potential outliers is largely managed. Synergy therefore does not support this methodology and suggests taking the median of the relevant level for each 12-month period in the preceding seven years.	
25	Alinta Energy	Alinta Energy does not support determining the RL_Fleet as the lower of the median of the $Annual\_RL\_Fleet$ values, and the $Full\_Period\_RL\_Fleet$, as outlined in proposed Step 9(d), for three reasons. Firstly, the ERA's final report states that the purpose of the adopting the median annual relevant level, rather than the average annual relevant level, is to avoid the relevant level being 'influenced by extremely large or small capacity value results'. However, compared with the average annual relevant level, Alinta Energy considers that the full period relevant level is equally exposed to influence by outlying results for a given year, and more so than the median. Consequently, adopting this value where it is lower than the median risks extremely low values skewing the results and underestimating the fleet's capacity value.	Please refer to section 6.1.7 of this report.
26	Alinta Energy	Secondly, part of the rationale behind using the minimum of the full period results and the median was that the median alone may be susceptible to extremely large or small	Please refer to section 6.1.7 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		values due to the 'small' sample size of five years. However, the Rule Change Proposal increases the sample size from five to seven years (under proposed Step 1(b)), making the median more resilient to outliers and the stated need for the full period results less relevant.	
27	Alinta Energy	Finally, Alinta Energy considers that taking the minimum of the full period results is inconsistent with the methods used in the SPP, PJM and MISO. As discussed in section 3.2.4 of Appendix 3, these systems use the average of annual estimates to set the capacity value for the fleet of intermittent generators. Unlike the proposed approach, these averages are exposed to both large and small values, whereas proposed Step 1(b) results in the fleet's capacity value only being exposed to small values. This is because Step 9(d) requires that the full period results only be used where it is lower than the median of the annual capacity values.	Please refer to section 6.1.7 of this report.
28	Alinta Energy	Considering the potential for the proposed Step 9(d) to underestimate the fleet's capacity value, the increased sample size, and the methods applied in the SPP, PJM and MISO systems, Alinta Energy recommends that Step 9(d) is amended so that the RL_Fleet is the median of the $Annual\_RL\_Fleet$ values.	Please refer to section 6.1.7 of this report.
Allocation of fleet ELCC to Candidate Facilities			
29	AEMO	Part A(c) of proposed Appendix 9 states: '*(c) each Candidate Facility will be assigned to one of the following Facility groups, <u>based on AEMO's</u>*	Please refer to section 6.1.8 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		assessment of the general profile of the Available Capacity of that Candidate Facility through the relevant Capacity Year.' The general profile of the Available Capacity will not be available for the relevant Capacity Year, which is two years in the future. For Existing Candidate Facilities, their Facility groups can be inherited from the previous RL calculation. AEMO's assessment of their general profiles of the Availability Capacity should not be required, thus reducing AEMO's administrative burden. AEMO suggests that: • This assessment should be based on the general profile of the Available Capacity from Meter Data Submissions and/or the expected capacity estimates provided in independent expert reports under clause 4.10.3 of the WEM Rules. • The assessment of Facility groups should only be required for New Candidate Facilities.	
30	AEMO	The formula in Part B, Step 10(d) of proposed Appendix 9 should use RL_Fleet determined under Step 9(d) of Part B of Appendix 9, instead of using $Full\_Period\_RL\_Fleet$. AEMO recommends that the Rule Change Panel reviews and updates this step accordingly.	The Rule Change Panel agrees with AEMO that RL_Fleet would be the correct value, but notes that the specific terms and calculations are not included in the draft RLM.
31	Alinta Energy	Alinta Energy considers that determining the relevant level for each facility group introduces complexity and potential issues. Consequently, Alinta Energy recommends that the	Please refer to section 6.1.8 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		Rule Change Panel consider whether this step, which was added following the ERA's draft report, is necessary. To aid consideration, Alinta Energy suggests sensitivity analysis is conducted to test the relative difference between the capacity values produced with and without this step. Alinta Energy recommends weighing this difference and its perceived improvement to the accuracy of facilities' relevant levels, against the following issues Alinta Energy perceives (issues 32 to 36 below).	
32	Alinta Energy	[Alinta's issues with determining the relevant level of each facility group] i) Volatility and sensitivity to withdrawals Section 1.5 in Appendix 4 of the Rule Change Proposal notes that the 'proposed method for allocating the fleet capacity value to facility classes will cause unnecessary variation in the results' and is likely to be 'highly variable and sensitive to changes in the generation mix'. While the proposal notes that the draft Amending Rules aim to offset this volatility by using the full-period technology group results, Alinta Energy suggests that including the step to determine facility group capacity values still increases the likelihood that withdrawals will significantly impact results, and necessitate the RLM being re-run.	Please refer to section 6.1.8 of this report.
33	Alinta Energy	[Alinta's issues with determining the relevant level of each facility group]	Please refer to section 6.1.8 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		ii) Risk that adjustment to wind and solar facility classes is incorrect The proposed method for determining the capacity value of facility classes assumes that the sole reason for any difference between the fleet capacity value and the sum of the facility class capacity values will be the correlation of wind and solar facilities. However, Alinta Energy considers that correlations between other facilities may influence this difference and that annual reviews would be required to ensure that wind and solar facilities are not being unfairly penalised for other sources of correlation in the fleet.	
34	Alinta Energy	[Alinta Energy's issues with determining the relevant level of each facility group] Alinta Energy suggests that another reason for the difference between the fleet's and the sum of the facility groups' capacity values may be the different way the two values are calculated. The current proposal calculates the fleet capacity using the median of annual results, whereas the facility group values are determined using full period results. Consequently, there appears to be a risk that wind solar resources will be penalised even where their correlation is not the cause of the difference between the fleet's and the sum of facility groups' capacity values.	Please refer to section 6.1.8 of this report.
35	Alinta Energy	[Alinta Energy's issues with determining the relevant level of each facility group]	Please refer to section 6.1.8 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		iii) Interaction index may not represent profiles of all the facilities within a facility group. Given the small sample size of wind farms in the SWIS, and the potential variety in their profiles, there is a risk that some wind farms may not be responsible for any of the facility group's correlation with the solar facility group, and bear a disproportionate discount to its Relevant Level.	
36	Alinta Energy	[Alinta Energy's issues with determining the relevant level of each facility group] iv) Complexity and transparency Incorporating facility group capacity values into the RLM adds numerous steps and concepts to the RLM, increasing complexity and potentially making it unnecessarily difficult for Market Participants and prospective investors to scrutinise the various factors that will influence the CRC of their facilities or potential investments.	Please refer to section 6.1.8 of this report.
Application of proposed RLM to assess Conditional CRC and Early CRC			
37	AEMO	When calculating the RL value for IGs that have applied for Conditional CRC, the proposed changes to clause 4.9.5(b) require AEMO to consider the IGs as Candidate Facilities to be included in the calculations for the preceding Reserve Capacity Cycle. This approach assumes the IGs had applied for the certification of Reserve Capacity in the preceding Reserve Capacity Cycle and applies inputs from	Please refer to section 6.1.11 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		the preceding Reserve Capacity Cycle for their RL calculation. AEMO notes that this requirement is not consistent with the requirements under the current WEM Rules as amended by the T2&3 Amending Rules that commenced on 1 February 2021. Where AEMO has received an application for certification of Reserve Capacity under clause 4.9.1 for a future Reserve Capacity Cycle, clause 4.9.7A requires AEMO to process the application at the time AEMO next processes applications for CRC for a Reserve Capacity Cycle. To be consistent with this requirement, AEMO considers that the proposed changes to clause 4.9.5(b) in the Rule Change Proposal should be amended such that AEMO is required to consider IGs that have applied for Conditional CRC as Candidate Facilities to be included in the RL calculations for the next Reserve Capacity Cycle.	
38	AEMO	The proposed change to clause 4.28C.1(e) prescribes that if the Facility is deemed by AEMO to be a Candidate Facility for the purpose of Appendix 9, the Facility would not be part of a Facility group with interaction index $i(c)$ equal to one, as per Step 10(a) of the Proposed RLM. AEMO understands that the purpose of this proposed change is to preclude Facilities that contain wind and/or solar generation systems applying for Early CRC, as their Facility groups have the interaction index of one under Step 10(a) of the Proposed RLM. This is to avoid such Facilities from affecting the RL calculation of wind and solar Candidate	The Rule Change Panel has clarified in Step 3.1 of the draft RLM that only Non-Intermittent Facilities that AEMO intends to assign CRC for the current Reserve Capacity Cycle and deems to be committed should be included in the COPT calculations. Please also refer to section 6.1.11 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		Facilities that have applied for the current Reserve Capacity. However, AEMO notes that the Rule Change Proposal does not include rule changes required to exclude SF that have applied for Early CRC in the calculation of the COPT. Including such Facilities in the COPT calculation will impact the RL calculation and very likely result in incorrect RL values calculated for the relevant Reserve Capacity Cycle.	
Transparency of proposed methodology			
39	AEMO	AEMO has reviewed the calculation examples provided in Sections 1.1 and 1.2 of the Rule Change Proposal and noticed the differences in the method applied in the calculation examples and the Proposed RLM, including: • the examples used a five-year sample period rather than a seven-year period as required in the Proposed RLM; • the examples calculated Facility groups' RL values for each 12-month period. This differs from the Proposed RLM, which requires calculating Facility groups' RL values for the entire seven-year period; and • one of the examples scaled the demand to meet the forecast 10% POE peak demand without accounting for DER uptake, as required under the Proposed RLM. AEMO notes that the inconsistencies in the calculation examples provided in the Rule Change Proposal with the Proposed RLM calculations may be due to the ERA having insufficient time to re-run the calculations prior to finalising	The Rule Change Panel has based its draft decision on its own analysis (undertaken by The Lantau Group) as outlined in section 6 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		the Rule Change Proposal. AEMO encourages the Rule Change Panel to consider providing examples based on the Proposed RLM to assist stakeholders in developing a clearer understanding of the expected outcomes from the Proposed RLM implementation in the RCM.	
40	Collgar	The ERA engaged the support of The Lantau Group (**TLG**) to assist in preparing the Rule Change Proposal to amend the RLM, including the amendment of the existing model and its use to run several scenarios based on input data provided by the ERA. The results of the several scenarios modelled by TLG indicate that the proposed RLM may enable a fairer allocation of Capacity Credits to Intermittent Generators. However, these results, derived by TLG, are of limited use – Market Participants and new entrants to the system would be best served if they can replicate the proposed RLM and assess the contribution of their capacity to the reliability of the SWIS and forecast the CRC they can receive (for their existing capacity and planned capacity additions). This would also better facilitate the achievement of the Wholesale Market Objective of transparency. The ERA should make the model and detailed inputs and assumptions (including adjusted meter data schedules and modelled facility output data for new entrant facilities) used by TLG for all scenarios available to Market Participants as soon as possible to enable them to adequately conduct their own evaluations and contribute effectively during the second submission period.	Please refer to sections 3.1 and 6.1.13 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		(Collgar also provides a list of the components of the Proposed RLM that Collgar deems crucial to the modelling of scenarios.)	
41	Synergy	Appendix 1, Part B Step 18: this appears to have been modified such that steps 19 and 20 are no longer required. However, step 18 only accounts for the publication of a provisional forecast of the Trading Intervals and not the actuals, as previously required under Step 20. Synergy suggests Appendix 1, Part B Step 20 is retained.	Please refer to section 6.1.13 of this report.
42	Alinta Energy	Alinta Energy considers that proposed method will improve transparency by removing the K and U parameters. These constant parameters appear to be ill-defined and their relevance to the capacity value of facilities is not clear to Market Participants.	Please refer to section 6.1.1 of this report.
43	Alinta Energy	Alinta Energy considers that proposed method will improve transparency because it allows Market Participants and prospective investors to predict the capacity value of their facilities more easily.	The Rule Change Panel considers that the draft RLM will be more transparent and will allow prospective investors to more easily predict the capacity value of their facilities, and will provide additional benefits, as discussed in section 6.1 of this report.
44	Alinta Energy	Alinta Energy considers that proposed method will improve transparency because it is more clearly resilient to changes in the SWIS; whereas the current method can result in unexpected impacts to facilities' CRC. This is because it does not correctly identify periods when capacity is most valuable, nor account the contribution of other intermittent generators in the system when assigning CRC to a given facility.	The Rule Change Panel agrees with Alinta Energy's concerns about the current RLM, but considers that the draft RLM will address these concerns more effectively than the proposed RLM in the Rule Change Proposal.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
Impact on CRC timeframes			
45	AEMO	The Proposed RLM requires the CRC quantities assigned to SFs and DSPs for the relevant Reserve Capacity Cycle to be used as an input. This means that the RL calculation must be undertaken after the CRC assessment and assignment of CRC to all SFs and DSPs. Therefore, processes that could previously be performed concurrently must now occur sequentially.	Please refer to section 6.1.11 of this report.
46	AEMO	Compared to the current RLM, the Proposed RLM requires significantly more inputs and calculation components. As such, AEMO will require additional time to process the inputs, carry out the RL calculation, and resolve any calculation issues that may arise while addressing any calculation queries that Market Participants may have as part of the process.	Please refer to section 6.1.11 of this report.
47	AEMO	AEMO estimates that the Proposed RLM would add a minimum of 7-9 Business Days to the time required for AEMO to prepare the calculation inputs (currently 4-5 Business Days, increasing to 9-12 Business Days) and complete the RL calculation (currently 3-4 Business Days, increasing to 5-6 Business Days). Without additional resources, it will be operationally challenging for AEMO to implement the Proposed RLM without an amendment to section 4.1 of the WEM Rules to extend the CRC assessment timeline (currently 35 Business Days and unchanged by the T2&3 Amending Rules).	Please refer to section 6.1.11 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
48	AEMO	AEMO considers that amending the date (outlined in clause 4.1.11) on which AEMO must cease to accept lodgement of applications for CRC to a date that is at least seven to nine Business Days earlier would be the best approach because: • The timeframe for the lodgement of CRC applications specified in clause 4.1.7 and clause 4.1.11 of the T2&3 Amending Rules will be 10 days longer than the timeframe defined under the current WEM Rules (62 days). This will provide a time allowance for the amendment to clause 4.1.11, noting that AEMO is unclear about the rationale around the timeframe extension. • An amendment to clause 4.1.11 does not require changes to other CRC timelines defined under section 4.1 except the date specified in clause 4.1.8. An amendment to clause 4.1.11 will require a consequential amendment that changes the date for publication of a WEM Electricity Statement of Opportunities report (**WEM ESOO**) by AEMO to a date that is 12 to 14 Business Days earlier than the current date defined under clause 4.1.8. This is to ensure that the Reserve Capacity Requirement is published in the WEM ESOO report prior to the closure of the CRC application window for the relevant Reserve Capacity Cycle.	Please refer to section 6.1.11 of this report.
49	AEMO	AEMO notes that in the Rule Change Proposal, the ERA suggested that AEMO could use its discretion (clause	Please refer to section 6.1.11 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		4.1.1C) to extend the CRC assessment timeline or can procure extra resources to complete the RL calculation. Operationally, it has been AEMO's longstanding practice to exercise the discretionary power in clause 4.1.1C only in exceptional circumstances. For example, the deferral of the certification timeline for the 2020 Reserve Capacity Cycle was due to the unprecedented impacts of COVID-19. AEMO can procure additional resources to carry out the RL calculation annually, however the ongoing operational costs will need to be accounted for in the AEMO next Allowable Revenue and Forecast Capital Expenditure submission. AEMO believes that the slight reduction in the submission timeframe doesn't impact Market Participants or affect market outcomes. As such, the timeline extension is a better approach than acquiring additional short-term resources which would tend to come at a higher cost.	
ERA review of the RLM			
50	AEMO	AEMO considers that an adjustment to the Proposed RLM is required to avoid a Reserve Capacity shortfall that could lead to system reliability issues. The adjustment should: • Account for a lack of historical wind farm output data during the weather conditions often associated with a 10% POE peak demand event. • Provide a level of certainty that is consistent with SFs and DSPs in the delivery of capacity expected to be available. AEMO recognises that any adjustment to the historical output of wind farms is complex and requires an	Please refer to section 6.1.5 of this report.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		investigation of all wind farms' performance-related parameters and limitations. Any adjustment must ensure that the adjusted output of the wind farms is statistically correlated with system demand and the output of other IGs in the system. This could be considered as part of the next RLM review during which available meteorological models and power de-rating features could be investigated to explain the possible effect of the available capacity of wind farms during very high air temperature periods.	
51	AEMO	[Regarding the ERA's periodic review of the RLM under clause 4.11.3C] The Proposed RLM is designed based on part (a) of the Planning Criterion in clause 4.5.9. It cannot be used to assess the RL values of IGs if the Reserve Capacity Requirement is set by part (b) of the Planning Criterion in clause 4.5.9. If AEMO assesses that the Reserve Capacity Requirement is set by part (b) of the Planning Criterion in the near future, a review of the Proposed RLM must be triggered to ensure the Proposed RLM is amended to be consistent with part (b) of the Planning Criterion. The Proposed RLM does not contain any iterations to account for the interaction of the RL calculation and the NAQ Framework. A review of the RLM must be triggered when the NAQ Framework significantly impacts the accuracy of the RL calculation under the Proposed RLM to ensure that system reliability is not undermined. AEMO suggests that the Rule Change Panel should add a clause that allows AEMO to request the ERA to commence	The Rule Change Panel does not consider that AEMO needs to be granted this power in the WEM Rules. The Rule Change Panel does not expect that the ERA would fail to undertake a review if either of the two scenarios contemplated by AEMO occurred and AEMO raised its concerns with the ERA and other Rule Participants.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		the review of the Proposed RLM, where AEMO considers an amendment to the Proposed RLM to be appropriate.	
52	Synergy	Clause 4.11.3C: Synergy is supportive of a delay to the next RLM review, however, considers a postponement to April 2022 insufficient time to review the application of the proposed method in practice. Synergy considers it more appropriate to delay the next RLM review until 1 April 2023, upon which the new RLM will be in place for a more satisfactory length of time.	The Rule Change Panel agrees with Synergy that the proposed April 2022 deadline for the next RLM review is too early. According to the timetables published by AEMO, AEMO will not publish CRC and Capacity Credit details for the 2021 Reserve Capacity Cycle until 28 April 2022, after the review deadline in the proposed Amending Rules. Given that AEMO intends to publish CRC and Capacity Credit details for the 2022 Reserve Capacity Cycle (the first to use the NAQ framework) on 4 October 2022, the Rule Change Panel considers that a more appropriate deadline for the next review is 1 April 2024; and has amended the proposed Amending Rules accordingly.
Drafting issues			
53	AEMO	AEMO urges the Rule Change Panel to ensure all defined terms, including those outlined in the T2&3 Amending Rules, used in rules enacting the Proposed RLM have commenced prior to or at the time of the rule amendments made under this Rule Change Proposal taking effect.	EPWA has confirmed that new clause 1.36C.6, which commenced on 1 February 2021, is intended to resolve the issue raised by AEMO. The Rule Change Panel suggests that AEMO and EPWA work together to determine whether the clause requires further amendment to either broaden its scope or explicitly refer to defined terms.
53	Synergy	Appendix 1 of the Rule Change Proposal outlines the marked-up changes to the market rules. However, these mark-ups are based on the draft Amending Rules for the	The Rule Change Panel notes that the base drafting in Appendix C of this report assumes the WEM Rules that are currently expected to be in place on

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		NAQ framework that have since been revised upon its gazettal in December 2020 (**Gazetted NAQ Rules**). Synergy recommends the Rule Change Panel addresses these inconsistencies that have arisen between the proposed Amending Rules and the recently Gazetted NAQ Rules to enable industry to more efficiently assess the proposed changes.	1 July 2021; and includes a number of essential changes made by the Rule Change Panel to the proposed Amending Rules to account for changes made to the Tranche 2&3 Amending Rules from the draft version used by the ERA to develop this Rule Change Proposal.
54	AEMO	Part A(c) of proposed Appendix 9 states: *'In determining the general profile of Available Capacity, AEMO must have regard to the technology, <u>Facility type and Facility Class of that Candidate Facility, as determined by AEMO based on the information specified in clauses 4.10.1</u> and 2.33.3 and……'* This appears to be inconsistent with the T2&3 Amending Rules: • It is not clear whether this step refers to Facility Technology Types as defined in the T2&3 Amending Rules or not. • For a new Facility, clause 4.8A.1 of the T2&3 Amending Rules requires AEMO to determine and assign an indicative Facility Class and an indicative Facility Technology Type based on information submitted in an Expression of Interest, rather than the information specified in clause 4.10.1. AEMO suggests that this step should be modified to be consistent with the requirement under clause 4.8A.1 of the T2&3 Amending Rules.	Please refer to the response to Issue 10 above.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
55	AEMO	Part B, Step 3 of proposed Appendix 9 states: *'For each Candidate Facility, identify any Trading Intervals in the period identified in Step 1(b) where the Facility was directed to restrict its Injection under a Dispatch Instruction with <u>a Dispatch Cap or Dispatch Target as published under</u> <u>clause [7.13.1x3(a)].'</u>* • It is not clear what rule clause [7.13.1x3(a)] is referring to. • Dispatch Cap and Dispatch Target are defined terms in the T2&3 Amending Rules. It's not clear how AEMO can identify these Trading Intervals for a seven-year period in the past, during which there may not be any Dispatch Caps or Dispatch Targets recorded. AEMO encourages the Rule Change Panel to engage with AEMO to identify a possible solution to identify the relevant Trading Intervals for a seven-year period in the past under this step.	The Rule Change Panel notes that the version of Appendix 9 that was included in the T2&3 Amending Rules, and which is currently scheduled to commence on 1 July 2021, assumes that the Real-Time Market and associated outage management rules are not only in place, but have been in operation since the start of the seven-year Reference Period. ETIU is aware of this issue and has advised the Rule Change Panel that it intends to restore the current version of Appendix 9 as soon as practicable. The draft RLM is based on the assumption that the current market arrangements are still in place, which will remain appropriate until the time that the new market arrangements commence. The Rule Change Panel expects that EPWA will need to make further changes to the WEM Rules by then to manage the transition from the current market arrangements to the new arrangements over the following 7 to 8 years.
56	Synergy	Appendix 1, Part B Step 3: reference to clause 7.13.1x3(a) does not exist under the Gazetted NAQ Rules and should be corrected.	Please refer to the response to Issue 55 above.
57	AEMO	Part B, Step 4 of proposed Appendix 9 states: *'For each Candidate Facility and Trading Interval identified in Step 3 identify the Sent Out Generation as the higher of:* *(a) the quantity determined in Step 2(a); and*	Please refer to the response to Issue 55 above.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		(b) if AEMO made a revised estimate under clause 7.13.7 that estimate, otherwise AEMO's estimate made under clause 7.13.6,…' For an aggregated Facility, it is unclear how to allocate the estimates made for the aggregated Facility under clause 7.13.7 or clause 7.13.6 to its different components which are treated as separate Candidate Facilities in the RL calculation under Step 7(c) of Appendix 9. AEMO encourages the Rule Change Panel to review and engage with AEMO to identify the best approach to allocate the estimate made under Step 4 of Appendix 9 to different components of an aggregated Facility.	
58	AEMO	Appendix 1, Part B Step 3 to Step 6A: Synergy notes that the adjustment to use the estimated values will still need to be undertaken for the historic data, and as such these adjustments will continue to be required until the seven-year historic period no longer contains data before the new market (or before the NAQ Framework for GIA facilities). As such that drafting and proposed deletion of these clauses needs to be reviewed to ensure that estimated values can be used for relevant historic data.	Please refer to the response to Issue 55 above.
59	AEMO	Step 7(a)(iii) and 7(a)(iv) of proposed Appendix 9 refer to clauses 7.13.1C(c) (to determine Interruptible_Reduction) and 7.13.1C(b) (to determine Involuntary_Reduction). Clauses 7.13.1C(c) and 7.13.1C(b) no longer exist under the T2&3 Amending Rules.	Please refer to the response to Issue 55 above.

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
		AEMO encourages the Rule Change Panel to engage with EPWA to identify the correct rule references and update Step 7(a) of Appendix 9 accordingly.	
60	AEMO	Part B, Step 14(c) refers to Forced Outage rates estimated using 'Market Procedure: Certification of Reserve Capacity specified in clause 3.21.12'. • The procedure in the rule is not identified by name and only by its head of power. 'Market Procedure: Certification of Reserve Capacity' may not be its name in future. All Market Procedures will become WEM Procedures under the Tranche 1 Amending Rules. • The head of power for this procedure is specified in clause 4.9.10, not clause 3.21.12. AEMO suggests the Rule Change Panel reviews and updates this step to refer to the WEM Procedure specified in clause 4.9.10.	The Rule Change Panel has amended the relevant step (now Step 3.2) to refer to the WEM Procedure specified in clause 4.9.10.
61	AEMO	It is stated in Step 17 of proposed Appendix 9 that the LOLE target is equal to or approximately eight Trading Intervals in 10 years. However, it is not clear if the target LOLE should be applied for a $Relevant\_Period$ of seven years or 12-month relevant period for the RL calculation. Step 17 says that the calculated LOLE is 'equal or approximate to eight Trading Intervals in 10 years'. 'Approximate' can include a wide range of values and is not necessarily the closest value to the LOLE target. This should be changed to 'equal or closest to'.	Please refer to section 6.1.6 of this report. With respect to the use of the term "equal or approximate to", the Rule Change Panel agrees with AEMO and has amended the wording in the corresponding step in the draft RLM (Step D.6) to "equal to or closest to".

Issue	Submitter	Comment/Issue Raised	Rule Change Panel's Response
Transitional requirements			
62	Synergy	It is unclear whether the Rule Change Proposal remains contemplative of introducing transitional arrangements that would require the phasing in of the proposed RLM over a 3-year period to smooth financial implications, as set out under clause 4.11.2(c). Synergy notes this clause may have been rejected upon prior consultation but if not, Synergy would not support this proposed transitional arrangement as it would adversely impact existing intermittent generators by assigning a lower than justified quantity of capacity credit, and hence NAQs, until they have fully transitioned to the new RLM. Synergy considers it unnecessary to introduce transitional arrangements which would distort financial outcomes and recommends a direct transition to the new RLM upon approval.	The Rule Change Panel clarifies that the Rule Change Proposal does not include a phasing in of the new proposed RLM. The Rule Change Panel's draft decision also does not include any transitional provisions.
Other issues			
63	AEMO	The proposed RLM is one of the key aspects that support the effectiveness of the RCM. AEMO notes that refining the Reserve Capacity refund mechanism may be another option to encourage capacity to be available when needed.	The Rule Change Panel notes that changes to the Reserve Capacity refund mechanism are outside of the scope of this Rule Change Proposal.

Appendix B. Worked Example of the Formation of a COPT

Assume a Non-Intermittent Fleet comprised of two Non-Intermittent Generating systems and a DSP:

- Gen A:
  - proposed CRC = 60 MW
  - Forced Outage Rate = 0.05
- Gen B:
  - proposed CRC = 40 MW
  - Forced Outage Rate = 0.02
- DSP C:
  - proposed CRC = 20 MW; and
  - deemed Forced Outage Rate = 0

The Reserve Capacity Requirement (RCR) for the Reserve Capacity Cycle is 100 MW.

Based on these assumptions:

- DCOQ_Adj = RCR / sum (CRC of NI Facilities) = 100/120
- Gen A DCOQ = 60 * 100 / 120 = 50 MW (available at all times)
- Gen B DCOQ = 40 * 100 / 120 = 33.3 MW (available at all times)
- DSP C DCOQ = 20 * 100 / 120 = 16.7 MW (available 8:00 AM to 8:00 PM on Business Days)

Two COPTs are needed for this example:

- one for Trading Intervals during which only the Non-Intermittent Generating Systems are available; and
- the other for the Trading Intervals during which DSP C is also available.

Two Trading Interval Groups will be required, and a COPT will be constructed for each of these Trading Intervals Groups.

COPT 1: for Trading Intervals where only the Non-Intermittent Generating Systems are available

The NI Facilities for COPT 1 are Gen A and Gen B, so:

- NIF_Max = 50 + 33.3 = 83.3 MW

Initialise COPT 1 as follows:[36]

X	P(X)
0	0
0.1	0
0.2	0
…	…
83.3	0

The process for Gen A:

$P(0) = (1 – FOR(Gen\ A)) \times P_{prev}(0) + FOR(Gen\ A) \times P_{prev}(0 – DCOQ(Gen\ A))$

$= (1 – 0.05) \times 1 + 0.05 \times 1$

$= 1$

$P(0.1) = (1 – FOR(Gen\ A)) \times P_{prev}(0.1) + FOR(Gen\ A) \times P_{prev}(0.1 – DCOQ(Gen\ A))$

$= (1 – 0.05) \times 0 + 0.05 \times 1$

$= 0.05$

…

$P(50) = (1 – FOR(Gen\ A)) \times P_{prev}(50.0) + FOR(Gen\ A) \times P_{prev}(50.0 – DCOQ(Gen\ A))$

$= (1 – 0.05) \times 0 + 0.05 \times P_{prev}(50.0 – 50.0)$

$= (1 – 0.05) \times 0 + 0.05 \times 1$

$= 0.05$

$P(50.1) = (1 – FOR(Gen\ A)) \times P_{prev}(50.1) + FOR(Gen\ A) \times P_{prev}(50.1 – DCOQ(Gen\ A))$

$= (1 – 0.05) \times 0 + 0.05 \times Pprev(50.1 – 50.0)$

$= (1 – 0.05) \times 0 + 0.05 \times 0$

$= 0$ (which means the end of processing Gen A)

[36] X is a MW outage quantity, and P(X) is the cumulative probability that at least that quantity of the certified capacity of the COPT Facilities will be unavailable due to Forced Outage.

After processing Gen A, COPT 1 looks like this:

X	P(X)
0	1
0.1	0.05
0.2	0.05
…	…
50.0	0.05
50.1	0
…	…
83.3	0

The process for Gen B:

P(0) = (1 – FOR(Gen B)) x P_{prev}(0) + FOR(Gen B) x P_{prev}(0 – DCOQ(Gen B))

= (1 – 0.02) x 1 + 0.02 x P_{prev}(0 – 33.3)

= 1

P(0.1) = (1 – FOR(Gen B)) x P_{prev}(0.1) + FOR(Gen B) x P_{prev}(0.1 – DCOQ(Gen B))

= (1 – 0.02) x 0.05 + 0.02 x P_{prev}(0.1 – 33.3)

= 0.98 x 0.05 + 0.02 x 1

= 0.069

P(0.2) = (1 – FOR(Gen B)) x P_{prev}(0.2) + FOR(Gen B) x P_{prev}(0.2 – DCOQ(Gen B))

= (1 – 0.02) x 0.05 + 0.02 x P_{prev}(0.2 – 33.3)

= 0.98 x 0.05 + 0.02 x 1

= 0.069

…

P(33.3) = 1 – FOR(Gen B)) x P_{prev}(33.3) + FOR(Gen B) x P_{prev}(33.3 – DCOQ(Gen B))

= (1 – 0.02) x 0.05 + 0.02 x P_{prev}(33.3 – 33.3)

= 0.98 x 0.05 + 0.02 x 1

= 0.069

P(33.4) = (1 – FOR(Gen B)) x P_{prev}(33.4) + FOR(Gen B) x P_{prev}(33.4 – DCOQ(Gen B))

= (1 – 0.02) x 0.05 + 0.02 x P_{prev}(33.4 – 33.3)

= 0.98 x 0.05 + 0.02 x 0.05

= 0.05

…

$$
\begin{aligned}
P(50.0) &= (1 - FOR(Gen\ B)) \times P_{prev}(50.0) + FOR(Gen\ B) \times P_{prev}(50.0 - DCOQ(Gen\ B)) \\
&= (1 - 0.02) \times 0.05 + 0.02 \times P_{prev}(50.0 - 33.3) \\
&= 0.98 \times 0.05 + 0.02 \times 0.05 \\
&= 0.05
\end{aligned}
$$

$$
\begin{aligned}
P(50.1) &= (1 - FOR(Gen\ B)) \times P_{prev}(50.1) + FOR(Gen\ B) \times P_{prev}(50.1 - DCOQ(Gen\ B)) \\
&= (1 - 0.02) \times 0 + 0.02 \times P_{prev}(50.1 - 33.3) \\
&= 0.98 \times 0 + 0.02 \times 0.05 \\
&= 0.001
\end{aligned}
$$

…

$$
\begin{aligned}
P(83.3) &= (1 - FOR(Gen\ B)) \times P_{prev}(83.3) + FOR(Gen\ B) \times P_{prev}(83.3 - DCOQ(Gen\ B)) \\
&= (1 - 0.02) \times 0 + 0.02 \times P_{prev}(83.3 - 33.3) \\
&= 0.98 \times 0 + 0.02 \times 0.05 \\
&= 0.001
\end{aligned}
$$

The final COPT 1 looks like this:

X	P(X)
0	1
0.1	0.069
0.2	0.069
…	…
33.3	0.069
33.4	0.05
…	…
50.0	0.05
50.1	0.001
…	…
83.3	0.001

COPT 2: for Trading Intervals where the Non-Intermittent Generating Systems and the DSP are available

The NI Facilities for COPT 2 are Gen A, Gen B and DSP C, so:

- NIF_Max = 50 + 33.3 + 16.7 = 100.0 MW

Initialise COPT 2 as follows:

X	P(X)
0	0
0.1	0
0.2	0
…	…
100.0	0

The process for Gen A:

The calculations for X from 0 to 50.1 for COPT 2 are the same as for COPT 1.

After processing Gen A COPT 2 looks like this:

X	P(X)
0	1
0.1	0.05
0.2	0.05
…	…
50.0	0.05
50.1	0
…	…
100.0	0

The process for Gen B:

The calculations for X from 0 to 83.3 for COPT 2 are the same as for COPT 1.

$P(83.4) = (1 – FOR(Gen\ B)) \times P_{prev}(83.4) + FOR(Gen\ B) \times P_{prev}(83.4 – DCOQ(Gen\ B))$

$= (1 – 0.02) \times 0 + 0.02 \times P_{prev}(83.4 – 33.3)$

$= 0.98 \times 0 + 0.02 \times 0$

= 0 (which means the end of processing Gen B)

After processing Gen B, COPT 2 looks like this:

X	P(X)
0	1
0.1	0.069
0.2	0.069
…	…
33.3	0.069
33.4	0.05
…	…
50.0	0.05
50.1	0.001
…	…
83.3	0.001
83.4	0
…	0
100.0	0

The process for DSP C:

The relevant calculations are shown below for completeness, but DSP C does not alter the P(X) values because its Forced Outage Rate is 0.

P(0) = (1 – FOR(DSP C)) x P_{prev}(0) + FOR(DSP C) x P_{prev}(0 – DCOQ(DSP C))

= (1 – 0) x 1 + 0 x Pprev(0 – 16.7)

= 1

P(0.1) = (1 – FOR(DSP C)) x P_{prev} (0.1) + FOR(DSP C) x P_{prev} (0.1 – DCOQ(DSP C))

= (1 – 0) x 0.069 + 0 x P_{prev} (0.1 – 16.7)

= 1 x 0.069 + 0 x 1

= 0.069

…

P(16.7) = (1 – FOR(DSP C)) x P_{prev} (16.7) + FOR(DSP C) x P_{prev} (16.7 – DCOQ(DSP C))

= (1 – 0) x 0.069 + 0 x P_{prev} (16.7 – 16.7)

= 1 x 0.069 + 0 x 1

= 0.069

P(16.8) = (1 – FOR(DSP C)) x P_{prev} (16.8) + FOR(DSP C) x P_{prev} (16.8 – DCOQ(DSP C))

= (1 – 0) x 0.069 + 0 x P_{prev} (16.8 – 16.7)

= 1 x 0.069 + 0 x 0.069

= 0.069

…

P(33.3) = (1 – FOR(DSP C)) x P_{prev} (33.3) + FOR(DSP C) x P_{prev} (33.3 – DCOQ(DSP C))

= (1 – 0) x 0.069 + 0 x P_{prev} (33.3 – 16.7)

= 1 x 0.069 + 0 x 0.069

= 0.069

P(33.4) = (1 – FOR(DSP C)) x P_{prev} (33.4) + FOR(DSP C) x P_{prev} (33.4 – DCOQ(DSP C))

= (1 – 0) x 0.05 + 0 x P_{prev} (33.4 – 16.7)

= 1 x 0.05 + 0 x 0.069

= 0.05

…

P(50.0) = (1 – FOR(DSP C)) x P_{prev} (50.0) + FOR(DSP C) x P_{prev} (50.0 – DCOQ(DSP C))

= (1 – 0) x 0.05 + 0 x P_{prev} (50.0 – 16.7)

= 1 x 0.05 + 0 x 0.069

= 0.05

$P(50.1) = (1 – FOR(DSP\ C)) \times P_{prev} (50.1) + FOR(DSP\ C) \times P_{prev} (50.1 – DCOQ(DSP\ C))$

$= (1 – 0) \times 0.001 + 0 \times P_{prev} (50.1 – 16.7)$

$= 1 \times 0.001 + 0 \times 0.05$

$= 0.001$

…

$P(66.7) = (1 – FOR(DSP\ C)) \times P_{prev} (66.7) + FOR(DSP\ C) \times P_{prev} (66.7 – DCOQ(DSP\ C))$

$= (1 – 0) \times 0.001 + 0 \times P_{prev} (66.7 – 16.7)$

$= 1 \times 0.001 + 0 \times 0.05$

$= 0.001$

$P(66.8) = (1 – FOR(DSP\ C)) \times P_{prev} (66.8) + FOR(DSP\ C) \times P_{prev} (66.8 – DCOQ(DSP\ C))$

$= (1 – 0) \times 0.001 + 0 \times P_{prev} (66.8 – 16.7)$

$= 1 \times 0.001 + 0 \times 0.001$

$= 0.001$

…

$P(83.3) = (1 – FOR(DSP\ C)) \times P_{prev} (83.3) + FOR(DSP\ C) \times P_{prev} (83.3 – DCOQ(DSP\ C))$

$= (1 – 0) \times 0.001 + 0 \times P_{prev} (83.3 – 16.7)$

$=1 \times 0.001 + 0 \times 0.001$

$= 0.001$

$P(83.4) = (1 – FOR(DSP\ C)) \times P_{prev} (83.4) + FOR(DSP\ C) \times P_{prev} (83.4 – DCOQ(DSP\ C))$

$= (1 – 0) \times 0 + 0 \times P_{prev} (83.4 – 16.7)$

$= 1 \times 0 + 0 \times 0.001$

= 0 (which means the end of processing DSP C)

The final COPT 2 looks like this:

X	P(X)
0	1
0.1	0.069
0.2	0.069
…	…
33.3	0.069
33.4	0.05
…	…
50.0	0.05
50.1	0.001
…	…
83.3	0.001
83.4	0
…	0
100.0	0

Appendix C. Further Amendments to the Proposed Amending Rules

Rule Change Proposal changes (other than to Appendix 9) reapplied to WEM Rules as of 1 July 2021 (based on information available on 28 March 2021) and changes accepted.

The Rule Change Panel proposes to make some further amendments to the proposed Amending Rules following the first submission period. Note that the base drafting in this appendix assumes the WEM Rules that are currently expected to be in place on 1 July 2021, and includes essential changes made by the Rule Change Panel to the original proposed Amending Rules to account for changes made to the T2&3 Amending Rules from the draft version used by the ERA to develop this Rule Change Proposal.

The Rule Change Panel has not included any changes to Appendix 9 in this Appendix C because the Rule Change Panel proposes to replace Appendix 9 in its entirety with the version specified in section 7 of this Draft Rule Change Report.

The other further amendments are as follows (~~deleted text~~, added text, clauses that are included for context but not amended):

4.9. Process for Applying for Certification of Reserve Capacity

…

The Rule Change Panel proposes not to implement the changes proposed by the ERA to clause 4.9.5, but instead to modify the wording of clause 4.9.5(c) to further clarify that Conditional CRC determined using the RLM is only indicative and a new Relevant Level must be calculated to determine the CRC for the current Reserve Capacity Cycle.

4.9.5. If AEMO assigns Certified Reserve Capacity to a Facility for a future Reserve Capacity Cycle under section 4.11 ("**Conditional Certified Reserve Capacity**"):

(a) the Conditional Certified Reserve Capacity is conditional upon~~:~~ the information included in the application for Certified Reserve Capacity remaining correct as at the date and time specified in clause 4.1.11 for that future Reserve Capacity Cycle;

~~i. the information included in the application for Certified Reserve Capacity remaining correct as at the date and time specified in clause 4.1.11 for that future Reserve Capacity Cycle; and~~

~~ii. AEMO's assessment of the Certified Reserve Capacity for the Facility for the Reserve Capacity Cycle, until the time specified in clause 4.1.15 for that future Reserve Capacity Cycle, remains equal to the Conditional Certified Reserve Capacity.~~

~~(b) For Facilities to which the relevant level method specified in clause 4.11.2(b) is applicable for the certification of Reserve Capacity, AEMO must determine the Conditional Certified Reserve Capacity by including the Facility as a Candidate Facility in determining Relevant Levels in the preceding Reserve Capacity Cycle assuming the Facility had applied for~~

~~the certification of Reserve Capacity in the preceding reserve capacity cycle. When determining Conditional Certified Reserve Capacity AEMO can also have regards to expected resource mix and demand in the SWIS for Year 3 of the future Reserve Capacity Cycle to which the Conditional Certified Reserve Capacity is being assigned to.~~

(~~c~~b) the Market Participant holding the Conditional Certified Reserve Capacity must, in accordance with clauses 4.9.1 and 4.9.3, re-lodge an application for Certified Reserve Capacity with AEMO between the date and time specified in clause 4.1.7 and the time specified in clause 4.1.11 for that future Reserve Capacity Cycle;

(~~d~~c) if AEMO is satisfied that the application re-lodged in accordance with clause 4.9.5(b) is consistent with the information upon which the Conditional Certified Reserve Capacity was assigned and is correct,~~ and AEMO's assessment of the Certified Reserve Capacity for the Facility remains equal to the Conditional Certified Reserve Capacity previously assigned to the Facility,~~ then AEMO must confirm:

i. the Certified Reserve Capacity;

ii. [Blank]; and

iii. the Reserve Capacity Security or DSM Reserve Capacity Security levels,

that were previously conditionally assigned, set or determined by AEMO, ~~subject to~~ except that the Certified Reserve Capacity for an Intermittent Generating System~~ being~~ must be redetermined and assigned in accordance with clause 4.11.2(b) for the current Reserve Capacity Cycle; and

(~~e~~d) if the application re-lodged in accordance with clause 4.9.5(b) is found by AEMO to be inaccurate or is not consistent with the information upon which the Conditional Certified Reserve Capacity was assigned,~~ or AEMO's assessment of the Certified Reserve Capacity for the Facility differs from the Conditional Certified Reserve Capacity previously assigned to the Facility~~ then AEMO must process the application without regard for the Conditional Certified Reserve Capacity.

…

New clause 4.9.11 requires AEMO to document how it will adjust the observed demand for the Reference Period to account for increasing levels of DER penetration. The requirement has been specified in a new clause rather than in clause 4.9.10 because the Minister has replaced clause 4.9.10 in the T2&3 Amending Rules but the commencement date for the change has not yet been set.

4.9.11. AEMO must document how it will determine the system demand profiles required under Step 4.2 of Appendix 9 in the WEM Procedure specified in clause 4.9.10.

...

4.10. Information Required for the Certification of Reserve Capacity

…

Clause 4.10.2 has been amended to refer to the new defined term RLM Reference Period.

4.10.2. The types of Facilities eligible to use the method described in clause 4.11.2(b), for the purpose of assigning Certified Reserve Capacity or Conditional Certified Reserve Capacity to the Facility are:

(a) components of Semi-Scheduled Facilities that are Intermittent Generating Systems;

(b) Non-Scheduled Facilities, except Non-Scheduled Facilities comprising only Electric Storage Resources that have not been in operation for the full ~~period of performance assessment identified in step 1(a) of Appendix 9~~ RLM Reference Period for the current Reserve Capacity Cycle; and

(c) Non-Scheduled Facilities comprising only Electric Storage Resources that have been in operation for the full ~~period of performance assessment identified in step 1(a) of Appendix 9~~ RLM Reference Period for the current Reserve Capacity Cycle.

<table><tr><td>Clause 4.10.3 has been amended to:
(a) refer to the new defined term RLM Reference Period; and
(b) remove the proposed requirement for an expert report for a candidate facility comprising multiple intermittent technology types (e.g. wind/solar hybrids facilities).</td></tr></table>

4.10.3. An application for certification of Reserve Capacity for a Facility, or component of a Facility, that is to be assessed using the method described in clause 4.11.2(b) for a Facility, or relevant component of a Facility, that:

(a) is yet to enter service;

(b) is to re-enter service after significant maintenance;

(c) is to re-enter service after having been upgraded; or

(d) has not operated with the configuration outlined in clause 4.10.1(dA) for the full ~~period of performance assessment identified in step 1(a) of the Relevant Level Method; or~~ RLM Reference Period for the current Reserve Capacity Cycle,

~~(e) for which no meter data is available to determine the quantity of electricity sent out as per Step 2(a) of Appendix 9,~~

must include a report prepared by an expert accredited by AEMO in accordance with clause 4.11.6. AEMO will use the report to assign Certified Reserve Capacity for the Facility, or the relevant component of the Facility, that is to be assessed using the method described in clause 4.11.2(b) and to determine the Required Level for that Facility in accordance with clause 4.11.3B(b).

Clause 4.10.3A has been amended to: (a) refer to the new defined term RLM Reference Period; and (b) maintain the current terminology for the estimated sent out energy quantities that are required to be included in experts reports.

4.10.3A. A report provided under clause 4.10.3 must include:

(a) for each Trading Interval during the ~~period identified in step 1(a) of Appendix 9~~ RLM Reference Period for the current Reserve Capacity Cycle a reasonable estimate of the expected energy ~~capacity (in MW)~~ that would have been ~~available to be~~ sent out by the Facility or the component of the Facility assessed using the method described in clause 4.11.2(b) had it been in operation. This estimate must factor in the effect of Planned Outages or Forced Outages on the ~~capacity available to be~~ sent out energy;

…

…

4.11. Setting Certified Reserve Capacity

Clause 4.11.1 has been amended to: (a) refer to the new defined term RLM Reference Period; and (b) use the standard terminology for temperature references in the WEM Rules.

4.11.1. Subject to clause 4.11.12, AEMO must apply the following principles in assigning a quantity of Certified Reserve Capacity to a Facility or relevant component of a Facility for the Reserve Capacity Cycle for which an application for Certified Reserve Capacity has been submitted in accordance with section 4.10:

(a) the Certified Reserve Capacity for a Scheduled Facility comprising only Non-intermittent Generating Systems for a Reserve Capacity Cycle must not exceed AEMO's reasonable expectation of the amount of capacity likely to be available, after netting off capacity required to serve Intermittent Loads, embedded loads and Parasitic Loads, for Peak Trading Intervals on Business Days from the Trading Day starting 1 October in Year 3 of the Reserve Capacity Cycle to the end of July in Year 4 of the Reserve Capacity Cycle, assuming an ambient temperature of ~~41oC~~ 41 degrees Celsius;

(b) for a Scheduled Facility comprising only Non-Intermittent Generating Systems, the Certified Reserve Capacity must not exceed the sum of the capacities specified in clauses 4.10.1(e)(ii) and 4.10.1(e)(iii);

(bA) where the Facility is an Energy Producing System, the Certified Reserve Capacity must not exceed the Declared Sent Out Capacity for the Facility notified to AEMO under clause 4.10.1(bA)(iii);

(bB) where two or more Facilities share a Declared Sent Out Capacity, the total quantity of Certified Reserve Capacity assigned to those Facilities must not exceed the Declared Sent Out Capacity;

(bC) for a Scheduled Facility containing an Electric Storage Resource or Semi-Scheduled Facility containing an Electric Storage Resource, the total quantity of Certified Reserve Capacity determined for the Electric Storage Resource must be determined by AEMO in accordance with clause 4.11.3;

(bD) for a Non-Scheduled Facility comprising only an Electric Storage Resource, including Small Aggregation of aggregated Electric Storage Resources, the total quantity of Certified Reserve Capacity must be:

i. determined in accordance with the Relevant Level Method determined in accordance with clause 4.11.2; or

ii. if the Electric Storage Resource has not been in operation for the full ~~period of performance assessment identified in step 1(a) of the Relevant Level Method~~ RLM Reference Period for the current Reserve Capacity Cycle, determined in accordance with clause 4.11.3;

(bE) for a Non-Scheduled Facility, excluding Non-Scheduled Facilities under clause 4.11.1(bD)(ii), the total quantity of Certified Reserve Capacity assigned to the Facility must be determined in accordance with the Relevant Level Method, determined in accordance with clause 4.11.2;

…

…

4.11.2. Where an applicant submits an application for Certified Reserve Capacity, in accordance with clause 4.10, and AEMO is required to use the method described in clause 4.11.2(b) to apply to an Intermittent Generating System or a Non-Scheduled Facility (excluding where clause 4.11.1(bD)(ii) applies), AEMO:

(a) [Blank];

(aA) [Blank]; and

(b) subject to clause 4.11.12, must assign a quantity of Certified Reserve Capacity to the relevant Facility or relevant component of a Facility for the Reserve Capacity Cycle equal to the Relevant Level as determined in accordance with the Relevant Level Method, but subject to clauses 4.11.1(bA), 4.11.1(bB), 4.11.1(c), 4.11.1(f) and 4.11.1(h).

…

Clause 4.11.3C has been amended to move the deadline for the next RLM review to 1 April 2024.

4.11.3C. For each three year period, beginning with the period commencing on ~~1 January 2022~~ 1 January 2024, the Economic Regulation Authority must, by 1 April of the first year of that period, conduct a review of the Relevant Level Method. In conducting the review, the Economic Regulation Authority:

(a) must examine the effectiveness of the Relevant Level Method in meeting the Wholesale Market Objectives; and

(b) may examine any other matters that the Economic Regulation Authority considers to be relevant.

…

4.11.3E. At the conclusion of a review under clause 4.11.3C, the Economic Regulation Authority must publish a final report containing:

(a) details of the Economic Regulation Authority's review of the Relevant Level Method;

(b) a summary of the submissions received during the consultation period;

(c) the Economic Regulation Authority's response to any issues raised in those submissions; and

(d) any recommended amendments to the Relevant Level Method which the Economic Regulation Authority intends to progress as a Rule Change Proposal.

…

The Rule Change Panel proposes not to implement the changes proposed by the ERA to clause 4.28C.1.

4.28C. Early Certification of Reserve Capacity

4.28C.1. This section 4.28C is applicable to Facilities to which the following conditions apply:

(a) the Facility is a new Facility;

(b) the Facility is a generating system; and

(c) the Facility is deemed by AEMO to be committed~~; and~~.

~~(d) if the Facility is deemed by AEMO to be a Candidate Facility for the purpose of Appendix 9, the Facility would not be part of a facility group with interaction index *i(c)* equal to one, as per Step 10(a) of the Relevant Level Method.~~

…

7.7. Dispatch Instructions

...

Clause 7.7.5A has been amended to: (a) update the Appendix 9 step references; and (b) replace "Relevant Level Methodology" with "Relevant Level Method".

7.7.5A. AEMO must develop a WEM Procedure specifying:

(a) information that a Market Participant must provide to AEMO, for each of the Market Participant's Non-Scheduled Generators, and for each Trading Interval, for the purposes of:

i. the estimate referred to in clause 7.7.5A(b);

ii. the revised estimate referred to in clause 7.7.5A(c);

iii. ~~step 6~~ Step 2.5 of Appendix 9; or

iv. ~~step 6A~~ Step 2.6 of Appendix 9;

(b) for the purposes of clause 7.7.5B and the Relevant Level Method~~ology~~ – one or more methods that may be used to estimate the maximum quantity of sent out energy (in MWh) that a Non-Scheduled Generator would have generated in a Trading Interval had a Dispatch Instruction not been issued for that Facility and for that Trading Interval;

(c) for the purposes of the Relevant Level Method~~ology~~ only – the process for revising an estimate that was made strictly in accordance with one of the methods that, under clause 7.7.5A(b), must be specified in the WEM Procedure; and

(d) for the purposes of clause 7.13.1C(e) – one or more methods that may be used to estimate the decrease in the output (in MWh) of each of Synergy's Non-Scheduled Generators as a result of an instruction from AEMO to deviate from the Dispatch Plan or change their commitment or output in accordance with clause 7.6A.3(a).

...

10.5. Public Information

10.5.1. AEMO must set the class of confidentiality status for the following information under clause 10.2.1 as Public and AEMO must make each item of information available from or via the WEM Website after that item of information becomes available to AEMO:

…

(f) the following Reserve Capacity information (if applicable):

…

x. the ~~following~~ information ~~identified~~ for a Reserve Capacity Cycle ~~under~~ specified in Step 11 of the Relevant Level Method~~:~~;

~~1. the Scaled Demand determined under Step 7(b) of Appendix 9 determined for each Trading Interval in the period identified in Step 1(a) of Appendix 9.~~

~~2. the Residual Demand calculated in Step 7(e) of Appendix 9 determined for each Trading Interval in the period identified in Step 1(a) of Appendix 9.~~

~~3. the Capacity Outage Probability Table calculated in Step 15(b) of Appendix 9.~~

~~4. the~~ $Annual\_RL\_Fleet$ ~~calculated in Step 9(a) of Appendix 9.~~

~~5. the~~ $Full\_Period\_RL\_Fleet$ ~~calculated in Step 9(b) of Appendix 9.~~

~~6. for each facility group~~ c ~~the~~ $Facility\_Group\_RL(c)$ ~~calculated in Step 9(c) of Appendix 9.~~

~~7.~~ $LOLE\_adjustment2$ ~~calculated in Step 17(c) of Appendix 9.~~

~~8. For each facility group~~ c~~, the~~ $Scaling\_Factor(c)$ ~~calculated in Step 12 of Appendix 9.~~

…

…

…

11. Glossary

…

~~**Observed Demand**: An estimate of the total amount of electricity demand in the SWIS in MW over a Trading Interval that should have been supplied through the transmission grid if no load was reduced or disconnected by AEMO, as calculated in Step 7(a) of Appendix 9.~~

…

Relevant Level: Means the MW quantity determined by AEMO in accordance with the Relevant Level Method~~ology~~.

Relevant Level Method: Means the method of determining the Relevant Level specified in Appendix 9.

...

RLM Reference Period: For a Reserve Capacity Cycle, the seven-year period ending at 8:00 AM on 1 April of Year 1 of that Reserve Capacity Cycle.