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

Minutes

Meeting Title:	Reserve Capacity Mechanism Review Working Group (RCMRWG)
Date:	19 October 2023
Time:	9:30 AM to 11:30 AM
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	
Manus Higgins	AEMO	
Toby Price	AEMO	
Mike Hales	AEMO	
Grace Liu	AEMO	
Oscar Carlberg	Alinta Energy	
Geoff Gaston	Change Energy	
Dr Matt Shanazari	Economic Regulation Authority (ERA)	
Jake Flynn	Collgar Wind Farm	
Andrew Stevens	Energy Person	
Patrick Peake	Perth Energy	
Paul Arias	Shell Energy	
Tessa Liddelow	Shell Energy	
Noel Schubert	Small-Use Consumer representative	
Daniel Kurz	Summit Southern Cross Power	
Rhiannon Bedola	Synergy	
Peter Huxtable	Water Corporation	
Mark McKinnon	Western Power	
Tim Robinson	Robinson Bowmaker Paul (RBP)	
Richard Bowmaker	RBP	
Ajith Sreenivasan	RBP	
Cameron Owen	Enel X	
Scott Cornish	Enel X	
Jenny Laidlaw	Energy Policy WA (EPWA)	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting with an Acknowledgment of Country and welcomed members. The Chair noted the competition and consumer law obligations.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	
3	**Draft Minutes of meeting 2023_09_21** The Chair noted minor comments from Mr Schubert. No other comments were received so the Chair confirmed the minutes as approved.	
4	**Sequencing of the Draft WEM Amending Rules implementing the outcomes of the RCM Review** The Chair noted that these Rules are to go to the Minister by the end of November. The Chair noted that there have been constructive discussions with AEMO, and that Mr Hales from AEMO will be leading the discussion and explaining the rationale for the Rules sequencing. The Chair stated that: • Energy Policy WA (EPWA) does not want to implement these rules in a way that means the standard Reserve Capacity Mechanism (RCM) timeframes need to be extended in any of the coming years; • EPWA supports what AEMO is proposing but is seeking views on the relative importance of different aspects of the reform package; and • AEMO will explain how the implementation of different aspects may impact on normal RCM timeframes and therefore need to be staggered. Mr Hales talked through Slide 2 (rule commencement) in the papers. He noted that: • the full set of proposed changes could not be implemented in the next 6 months (i.e. before the next certification application window opens); • AEMO has considered how to best stage implementation to incentivize the entry of new capacity in the next year or two to meet the capacity shortfall without jeopardizing the capacity timeline; • staging will be in 2 parts: peak capacity product, and the changes related to that, followed by the new flexible capacity product; • stage 1, to be implemented for the 2024 cycle, will include the Demand Side Programmes (DSP) certification changes and the new Relevant Level Method (RLM). The change to the Reserve Capacity Refunds will also be implemented by October 2024; • component pricing cannot be achieved in time for the certification applications window opening in April, as the system changes are significant;	

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	• changes to the Individual Reserve Capacity Requirement (IRCR) will be in place for year 3 of the 2024 cycle (i.e. 2026). Mr Hales talked through Slide 3 (proposed commencement of changes) in the papers. Mr Hales talked through Slide 4 (preliminary RCM constraint equations) in the papers. He noted that: • The Expression of Interest (EOI) process is not mandatory. However, it is still used in Appendix 3 for tie-breaking so there is an advantage for participants to participate in it. • When new facilities submit an EOI, AEMO has to provide those new facilities to Western Power, and must create new preliminary RCM constraint equations and publish these in May. These constraint equations would consider existing facilities and only new facilities who had participated in the EOI, and therefore would not be complete. • When the final RCM constraint equations, that are required for the NAQ modelling are available in August, they would include facilities that have applied for Certified Reserve Capacity (CRC) and would be likely to change relative to the preliminary equations published earlier. Mr Hales asked whether participants find the preliminary RCM constraint equations beneficial and whether the non-mandatory EOI is still useful. The Chair noted that EPWA needed a prompt response to finalise the amending rules. • Mr Carlberg stated that there is no benefit in the preliminary equations, for Alinta, as there is no one internally who can use them in a practical way. • Mr Peake agreed with Mr Carlberg. • Mr Schubert noted that many new proponents, who may have views on this, may be absent from this meeting. The Chair acknowledged this but noted the need to make a decision. • Mr Stevens stated that any contemporary information on constraints that can be acquired would be useful and that constraints are a major factor influencing investment decisions. The Chair noted that, given EOIs will not be compulsory going forward, the information may not be that contemporary. • Mr Stevens agreed that this would be a problem and noted that Western Power already finds it difficult to manage new connections and it takes time to determine how constraints will affect those connections. • Mr Stevens asked whether facilities should be compelled to submit an EOI unless their facility is already accounted for in constraint equations through other means (e.g. because they have already lodged a connection application) to ensure accuracy in constraint equations.	

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- Mr Peake noted that a compulsory EOI process means the constraint equations will include projects that are unlikely to go ahead.

The Chair agreed and noted that with a compulsory EOI participants have previously put a number of variants of their facility so they don't miss out, a high proportion of which never made it to certification.

- Mr Stevens agreed that there should be some reasonable hurdle to expressing interest in joining the grid (and therefore included in constraint equations) and asked whether this should be workshopped between AEMO and Western Power to achieve alignment.

The Chair noted that the draft amending rules have gone in the opposite direction. They would allow participants to provide evidence when they submit their certification application that they will have an ETAC (rather than having to have one already, as this has been a major obstacle to certifying facilities).

- Mr Stevens noted that there is often a misalignment between what AEMO and Western Power need at early stages. Western Power has changed its connection process and taken steps to weed out applicants who aren't serious at early stages (through application fees). He suggested that the changed connection process should align with a potential filter for AEMO at the EOI stage so that the two processes work together.

The Chair acknowledged that the misalignment is causing issues for participants and AEMO. She noted that Western Power's connection processes should continue to improve and that Western Power and AEMO should work together to achieve alignment.

- Mr Kurz agreed with Mr Stevens' comments in regard to the balance between accessibility and realistic outcomes. He agreed that it is up to Western Power and AEMO to work out the appropriate balance.

The Chair noted that the conclusion is that if the constraint equations are accurate then they are useful.

Mr Hales discussed slide 5 (peak IRCR and reserve capacity rebate). He noted that there may be benefits to implementing IRCR alongside the commencement of the 5-minute settlement (5MS) and cost allocation review (CAR) amending rules and asked whether participants agree, or want to see this happen earlier/later.

The Chair clarified that the peak IRCR methodology will be implemented immediately for the purposes of the RLM and that what is being discussed now related only to the allocation of capacity costs.

- Mr Kurz asked when the Non-Temperature Dependent Load (NTDL) and Temperature Dependent Load (TDL) changes would happen.

Mr Hales confirmed that they would be included with this package, along with the changes to appendix 5.

The Chair clarified that changes to Appendix 5 that are needed for the purposes of the RLM would commence in 2024.

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Mr Hales noted that it is possible for the NTDL/TDL changes to commence in 2024 if there is a strong preference for that from participants, however 2025 or 2026 is AEMO's preference.

- Mrs Bedola noted that the NTDL/TDL, IRCR and refunds reforms are not being implemented in the first package in 2024, but that these are the 3 reforms with the biggest customer impacts.

The Chair noted that refunds are being changed (to be returned to (market) customers) as of October 2024.

- Mrs Bedola asked how complex the NTDL/TDL changes are to implement and noted that Synergy would prefer these to be implemented earlier, if possible, to better share costs across all customers.
- Mr Carlberg stated that later is better to avoid risks of delaying higher priority items. 5MS and CAR are last on Alinta's list.

The Chair noted that IRCR, 5MS and CAR changes are only linked from a systems development point of view.

- Mr Kurz stated that 2025 or 2026 for the changes is more practical for resulting changes to retail contracts which are priced typically for 2 years.
- Mrs Bedola asked whether there is an issue with the DSP changes being implemented but not the IRCR changes, as DSPs will be certified on the basis of the IRCR set using the current methodology, which will change by the time the obligations come into effect.

The Chair and Mr Hales noted that there is still an IRCR to use for certification and that there will need to be a cutover at some point.

The Chair asked how long retailers needed to change arrangements with customers as a result of the NTDL/TDL changes.

- Mr Kurz stated that sufficient time would be required for that retail contract to go through the natural cycle of renewal.
- Mr Gaston noted that there are change in law provisions in contracts to allow for these type of changes. He considered that refunds and NTDL/TDL should come in 2024, and that changing peak IRCR can be deferred until 2025.

The Chair summarized the discussion as follows:

  - there is no strong objection for peak IRCR to be delayed to 2025;
  - refunds changes should be implemented as soon as practicable; and
  - there are mixed views on whether to implement NTDL/TDL in 2024 (Mrs Bedola, Mr Gaston) or 2025 (Mr Kurz and Mr Carlberg).

- Mr Arias asked Mr Hales whether AEMO's costs change much depending on whether the changes are done all at once or in tranches.

Mr Hales noted that the NTDL/TDL changes could not be separated from the rest of the changes in Appendix 5, as this would be complex/costly.

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	• Mr Carlberg noted that implementing all the changes together would allow better visibility of system implications. The Chair summarised that the view was to implement all changes together for 1 October 2025, but commence changes to refunds as soon as possible. • Mr Kurz supported this. Mr Hales talked through Slides 6 and 7 in the meeting papers and requested feedback on the preferred option from participants. Ms Lui clarified that the preliminary values in Option 1 would just be based on the 2024 ESOO with no additional analysis/updates. The Chair clarified Options 1 and 2 as follows. Option 1 – AEMO does a preliminary assessment, on the basis of the 2024 Electricity Statement of Opportunities (ESOO) and releases this in January, and does a final assessment for the ESOO and releases that on 10 June. Parameters may change a bit but the ESOO is a week earlier to allow participants more time to consider the information. Option 2 – for certain parameters, AEMO will publish a final determination in January based on the 2024 ESOO. Remaining parameters to be released in the ESOO on 17 June. Ms Lui noted that for the 2025 cycle, data related to the flexible capacity product would be provided in 2025 Request for EOI report as a transitional arrangement as that data wouldn't be in the 2024 ESOO. In future years, the preliminary values for option 1 would be based on the previous ESOO. • Mr Carlberg asked what the expected benefit of Option 1 was if the information released in January was not updated from the previous ESOO (and therefore is information participants would already have). Ms Lui stated that it would be put together with the EOI information for participants. • Mr Carlberg reiterated that it was difficult to see any additional benefit that was being offered. The Chair agreed with Mr Carlberg that it was difficult to see the benefits and asked whether the simplest option would be to move the ESOO to 10 June. Ms Lui noted that this is option 1. Ms Lui reiterated that she considered providing consolidated information in an EOI request would be beneficial to new participants, even if it is not new information. • Mr Peake asked whether, historically, there has been much change in data between January and June. He stated a preference for as much data to be settled at the EOI stage as possible. The Chair noted that some of parameters (e.g. Reserve Capacity Target) cannot be determined without the forecast in the ESOO.	

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	• Mrs Bedola asked where the bottlenecks are in the ESOO and why it couldn't be moved even earlier, as best outcome would be to get complete information as soon as possible. Ms Lui noted that AEMO needs to have enough time to analyze data from the hot season (which runs until the end of March), to run the model and get approval from the Board. The Chair suggested that there is a third option in which the ESOO is still released in June but some of the actual parameters on slide 7 are published several weeks earlier. Ms Lui took this on notice and will advise whether this is possible. Mrs Bedola expressed support for this option.	
	Action: AEMO to determine whether key parameters can be published in the weeks before ESOO publication.	**AEMO**
	• Mr Schubert noted that events over summer can affect the forecast. He considered that option 1 is better as January is too early for final requirements. • Mrs Bedola asked whether the flexible product was intended to be in place for next year. The Chair clarified that the requirements would be published next year so that participants can start preparing proposals for the following year, but that systems will not be implemented for certification next year. Mr Hales confirmed that the publication of the flexible reserve capacity requirement will not be ready for the June 2024 ESOO and needs to be delayed until the 2025 EOI document in January to give AEMO time to develop that information. This will be a transitional arrangement and then the information will be incorporated into the June ESOO in future years. • Mrs Bedola queried whether the requirements for flexible capacity could be developed in a more timely manner by looking at the requirements for ESS facilities (e.g. ability to start, stop and ramp quickly) and mimicking those. She noted that facilities providing contingency services would have a ramp rate requirement. Mr Price clarified that more work needed to be done to look at the fleet, as well as the projected ramp requirements, and from that to develop the specification for participating in the flexible capacity product. • Mr Peake asked whether certification can be pushed back a week or so rather than the ESOO being brought forward. • Mr Carlberg also asked whether the CRC window could be delayed as the key difficulty tends to be getting network access signed by then rather than the ESOO. The Chair noted that it would not be feasible for AEMO to compress timeframes any further. The chair summarised the discussion, as follows: • AEMO has an action to look at an option to publish data essential for certification of new facilities prior to the ESOO on 17 June; and	

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	• no comments were provided on the transitional arrangements for implementing the flexible capacity product. Mr Hales went back to Slide 3 (proposed commencement). • Mrs Bedola stated that the key priority should be implementing the flexible capacity product and component pricing to address projected capacity shortfalls, and that DSP changes are less important. The Chair noted that component pricing is limited by system changes and that rules will be made in December 2023 to provide clarity about how it will apply. Mr Hales confirmed that this will take 18 months for AEMO to implement, as it requires a significant rebuild of the RCM systems, and the earliest it can be applied is 2025. • Mrs Bedola asked whether certification in 2024 would be on the basis of separate components. She noted that, if certification based on separate components only happened in 2025, pricing would only apply in 2027. • Mr Carlberg agreed with Mrs Bedola. Mr Hales noted that prices are calculated as part of certification and system changes are required for this. AEMO would have to change prices after the fact if capacity is certified on the basis of component pricing in 2024. The Chair requested that AEMO confirms this	
	Action: AEMO to confirm why component pricing is needed for the certification process, and to check whether it is possible to certify on the basis of component pricing in 2024 and settle on that basis in 2026.	**AEMO**
	• Mr Schubert stated that implementing the flexible capacity product could be delayed a few years (as per the slide) because there is enough in the system now and new batteries have been announced. The system is short of peak capacity and needs more DSPs in the short term to service this. • Mrs Bedola expressed concerns about the DSP changes, including the limited dispatch requirements and the price parity with capability class 1 facilities. She expressed concerns about making it easier for DSP to participate when thermal generators in the capability class 2 are getting paid less but have more availability requirements than DSPs. The Chair noted that the policy decision has already been made and will not be revisited, and that the question now is about implementation. • Mrs Bedola clarified that her preference is that the DSP changes be delayed as long as possible. Mr Carlberg stated the DSP changes were also not a priority for Alinta. • Mr Peake stated that if the DSP changes can be done easily, then they should be done as soon as possible.	

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	• Mrs Bedola asked whether it would be easier to get component pricing in for the 2024 certification if DSP is delayed. Mr Hales stated that DSP system changes are minimal and moving them won't affect anything else. He noted that, of the 2024 changes, RLM system changes are more complex. • Mr Schubert reiterated that the system needs peak capacity, and thus more DSPs, in the short term. The Chair noted that, if this change is not made, then DSPs will not participate in the capacity mechanism, and AEMO will be required to call supplementary capacity each year. Procuring DSPs through supplementary capacity will cost much more than incentivizing participation in the RCM. Mr Peake noted that the only way to see if DSPs are contributing is to try them.	
5	**BRCP Reference Technology Review – Net/Gross CONE analysis** Before discussing the BRCP, Mr Robinson noted that in the early comments on the Amending Rules some matters come up about Demand Side Programmes (DSP). Firstly, Mr Robinson noted that under the Amending Rules a DSP's capability to deliver a reduction will be measured against its actual demand, not its relevant demand and that consumption deviation applications will also be removed. If one of the loads in a DSP is on outage, then the minimum load proposed for that facility is still counted. Given the above, it is proposed to move from standing data minimum demand to real time minimum demand and allow DSPs to adjust their minimum demand more regularly. The DSP will still be required to have enough gap between actual consumption and minimum demand to ensure it can deliver the demand side response it is certified for. No comments were received. Mr Robinson noted that the Amending Rules also propose changes to the DSP refunds. He noted that currently the refund rate for the availability requirement and the dispatch requirement are the same. It is proposed to set these differently – the rates for dispatch non-compliance would be based on the DSP dispatch requirement but if it doesn't meet the availability requirements the refund would be based on the required availability hours (e.g. 20 hours). • Mr Carlberg considered that the proposal should be to shorten the period over which refund rate will be based. • Mrs Bedola supported Mr Carlberg. • Mr Cameron noted that a generator on a forced outage for 2 months a year would lose all of its capacity credits, while a DSP on 100% forced outage for 2.5 days would lose all of its capacity credits and an additional 25% as a punitive measure. He considered this unnecessary and supported a punitive measure if a DSP does not deliver when called on by AEMO but outside of that would prefer if DSPs are treated in line with all generators.	

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The Chair noted that EPWA is trying to strike a balance between not being overly punitive and the obligations on DSPs, which are significantly less than those for generators.

- Mr Cameron supports the availability refunds being based on the number of hours that the DSP is required to be available for dispatch (12 hours per day).

The Chair noted that DSPs are not required to log forced outages and that the intent of this proposal is to measure the DSPs minimum load in the hours when they have to be available and apply the penalty to this, rather than the one interval when they do not respond.

- Mr Stevens supported DSPs being subject to the extra penalty.
- Mrs Bedola supported DSPs having to pay refunds on the basis of availability hours.

Mr Robinson thanked members for their feedback.

Mr Bowmaker started the discussion on the net/gross CONE analysis. He summarised the approach taken in the BRCP Reference Technology Review and recapped that the most efficient new entrant technology on a gross CONE basis for both the Peak and Flex Service is a 200MW / 800MWh lithium battery energy storage system (BESS) connected at 330kV.

Mr Bowmaker presented the approach taken to analyse the gross and net cost of new entry (CONE), noting that:

- For the peak product, gross CONE would be applied if the reference technology would be the marginal energy supplier. If not, further assessment would be required on whether applying net CONE would be appropriate.
- For the flex product, if the reference technology was the marginal energy supplier in the intervals where flex capacity would be required then gross CONE should be applied. If not, further assessment would be required on whether applying net CONE would be appropriate.
- This was done using the WEMSIM model to forecast energy market prices, marginal cost of generation and the net market revenue for the reference technology facility, and gross and net CONE.

Mr Bowmaker noted that the modelling results are indicative only and should not be relied on for any other purpose.

Mr Bowmaker explained that the BESS would not be the marginal energy supplier for either product for the next 10 years.

Further analysis was required to determine whether gross or net CONE should be used. This showed the net CONE was significantly lower cost than the gross CONE, but that the results were highly dependent on inputs and sensitivity analysis showed the two results closely converging.

An assessment of the advantages and disadvantages of each showed that gross CONE however would provide higher investment certainty and be a simpler approach, while net CONE would require modelling that is highly sensitive to inputs which may undermine investment certainty.

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	• Dr Shahnazari agreed that net CONE would create uncertainty and create administrative problems, but large profit margins would pose a cost to consumers. He considered that there may be other solutions to manage the uncertainty. For example, when the ERA calibrates the reserve capacity price curve it could be mindful of the decision to adopt the gross CONE and reduce the buffer on the curve when surplus capacity gets close to zero. The Chair noted that there is a specific item in the WEM Investment Certainty Review to deal with the reserve capacity price curve which will be discussed on 8 November 2023. • Mr Schubert considered that the analysis presented needed further discussion. The Chair agreed to discuss further with Mr Schubert and RBP and noted that there will be public consultation on this topic shortly. • Mr Arias considered that gross CONE would be the simplest approach, noting the need to balance simplicity, cost and investment certainty. • Mr Carlberg considered that net CONE would create risk for new proponents, especially as more renewables enter the market. The Chair responded that analysis was undertaken during the RCM review, which indicated that storage would be profitable to 2050. • Mrs Bedola agreed that net CONE creates a barrier. The Chair noted that gross CONE may need to be considered in the ERA's offer construction guideline. • Mr Carlberg raised concerns around investor uncertainty if the net CONE approach is used. • Mr Schubert suggested using gross CONE, and then undertaking a review to determine which approach should be chosen over time. The Chair considered that this is a good suggestion and suggested that reviews should occur every three years, rather than every five years. • Mr Schubert considered that the ERA could annually monitor the difference between gross and net CONE. The Chair responded that setting gross or net CONE is now the Coordinator's role. Mr Peake agreed with Mr Carlberg and Mr Schubert.	
6	**General Business** No general business was discussed	

The meeting closed at 11:30am