Government of **Western Australia**
Energy Policy WA

Reserve Capacity Mechanism Review Working Group

Meeting 2023_07_06

6 July 2023

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

Meeting Protocols

- Please place your microphone on mute, unless you are asking a question or making a comment
- Please keep questions relevant to the agenda item being discussed
- If there is not a break in discussion and you would like to say something, you can use the ‘raise your hand’ function in Teams or comment in the meeting chat
- Questions and comments can also be emailed to EPWA - Energy Markets energymarkets@dmirs.wa.gov.au after the meeting
- The meeting will be recorded and minutes will be taken (actions and recommendations only)
- Please state your name and organisation when you ask a question
- If you are having connection/bandwidth issues, you may want to disable the incoming and/or outgoing video

Agenda

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda	Chair	Noting	2 min
2	Meeting Apologies/Attendance	Chair	Noting	2 min
3	Removal of mandatory EOI response	RBP	Discussion	5 min
4	ESR obligations for Flexible Capacity	RBP	Discussion	15 min
5	Flexible IRCR – addressing gaming potential	RBP	Discussion	15 min
6	Flexible Capacity refunds	RBP	Discussion	15 min
7	DSP capacity certification approach	RBP	Discussion	15 min
8	DSP dispatch commitment	RBP	Discussion	15 min
9	DSP refund cap	RBP	Discussion	15 min
10	General business	Chair	Discussion	15 min
11	Next Steps	Chair	Noting	5 min

Context

This working group session covers:

- Two items not raised in the consultation paper that have been raised by stakeholders outside of the Review or have arisen during rule drafting for the RCM Review Stage 1 outcomes
- Topics from the RCM Review Stage 2 consultation paper where EPWA is considering adjusting the design based on submissions.

It is not a forum for re-prosecuting arguments made in submissions or in the previous working group process. Nevertheless there will be an opportunity for discussion on other topics at the end of the session.

3. Removal of mandatory EOI response

Removal of mandatory Expressions of Interest

In June 2021, the Tranche 2 and 3 Amending Rules introduced a new rule 4.2.1 requiring participants to submit an Expression of Interest (EOI) as a condition of being eligible to seek certification of Reserve Capacity. This requirement applied for the 2022 and 2023 reserve capacity cycles, for CRC assigned for the 2024 and 2025 Capacity Years.

The requirement resulted in a significant increase in EOIs from prospective capacity providers, many of which were speculative or included multiple potential configurations for a single facility.

Year	2010	2011	2012	2013	2014	2015/16	2017	2018	2019	2020	2021	2022	2023
EOIs	16	8	17	9	5	1	3	1	2	3	29	164	137
Unique valid EOIs	16	8	17	9	5	1	3	1	2	3	25	91	72
DSP MW	228	101	19	2	0.25	0	0	0	0	0	5	0	0
Total MW	644	337	214	59	56	42	323	10	32	62	301	1311	1077

EPWA considers that the requirement has not produced any additional certainty about what capacity will actually be available, has resulted in wasted effort to process speculative and uncertain EOIs and may have created a barrier for proposals that may be otherwise viable.

The requirement will be removed from the 2024 Capacity Cycle.

Facilities for which an EOI is submitted will be allocated NAQ ahead of those for which no EOI was received, as per the rules that existed before Tranche 3.

4. ESR obligations for Flexible Capacity

Energy Storage Resources providing Flexible Capacity

Energy Storage Resources (ESR) are energy limited. Peak Capacity obligations effectively require them to be fully charged at the beginning of the four-hour ESR Obligation Intervals (currently 4.30pm to 8.30pm).

If required to discharge at more than their CC level, ESR RCOQ is reduced to zero for subsequent ESROIs.

ESRs are likely to meet minimum technical standards to provide Flexible Capacity – they are fast starting, fast ramping, and have no minimum generation level. However, if discharged through the ramp period (expected to be approximately 2-6pm), they would not be available in the final ESROIs.

In drafting Flexible Capacity obligations for ESR, EPWA identified two options:

A. Where ESRs provide both Peak and Flexible Capacity, derate CRC to reflect a longer discharge requirement covering both the ramp and the peak

B. Where ESRs are dispatched through the ramp, reduce ESR RCOQ to zero for subsequent peak intervals.

Given that the peak demand occurs in the hot season and peak ramping occurs outside the hot season, EPWA considers that option B is an acceptable approach:

- When ESRs are discharged through the steepest ramp period, other facilities can be available to meet later peak demand on those days.
- When ESRs are needed during system peak demand, the ramp is shallower, and other facilities can be called on during the pre-peak demand period.

If peak demand and steepest ramp periods converge to the same days in the future, this would need to be revisited.

5. Flexible IRCR – addressing gaming potential

Consultation Paper Proposal F

1. For each Trading Interval in the previous Capacity Year, find the difference between the operational load at the end of the Trading Interval and the load at the end of the Trading Interval four hours prior.
2. Select the three Trading Days with the highest four-hour ramp value calculated under step 1.
3. For each Trading Day selected under step 2:
    a. select the Trading Interval with the largest value calculated under step 1; and
    b. select all Trading Intervals in the previous four hours.
4. For each participant load portfolio:
    a. calculate the portfolio ramp contribution for each day selected in step 2 as the difference between consumption at the start of the earliest selected Trading Interval and the end of the latest selected Trading Interval; and
    b. calculate the portfolio annual ramp contribution as the mean of the portfolio ramp contributions determined in step 4a.
5. Calculate scaling factor R as the RCR for Flexible Capacity divided by the sum of all portfolio annual ramp contributions.
6. For each participant load portfolio, set the flexible IRCR as the portfolio annual ramp contribution multiplied by the scaling factor.

Potential gaming opportunity

One submission observed the potential for participants to game the Flexible IRCR allocation process. By briefly increasing load at the start of the Flexible IRCR assessment period (for example by turning off BTM solar), the difference between load at the start and end of the period would be minimised, and may potentially avoid Flexible IRCR allocation entirely. This behaviour would affect the timing of the ramp, while not affecting its size.

This behaviour would only be feasible for participants who have BTM generation (or can briefly increase load) and who can accurately predict the start of the ramp period. Nevertheless, there are several methods by which it could be countered, while not significantly increasing the complexity of the Flexible IRCR calculation.

Options

Five options explored:

A. Consultation paper proposal: difference between last interval and first interval.
   TI8-TI1

B. Mean interval change: Mean of interval-to-interval ramps (whether increase or decrease).
   Mean(TI8-TI7,TI7-TI6,TI6-TI5,TI5-TI4,TI4-TI3,TI3-TI2,TI2-TI1)

C. Mean interval increase: Mean of interval-to-interval ramps (increase only)
   Mean(Max(0,TI8-TI7), Max(0,TI7-TI6), Max(0,TI6-TI5), Max(0,TI5-TI4), …Max(0,TI2-TI1))

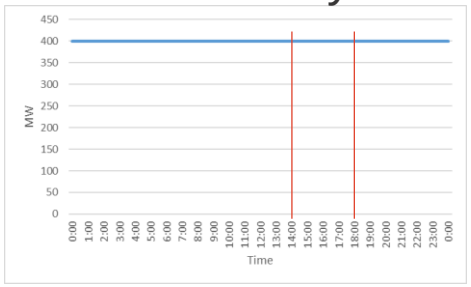
D. Pairwise maximum: Maximum increase between any two intervals in the period.
   Max(TI8-TI7, TI8-TI6,…TI8-TI1, TI7-TI6, TI7-TI5,…TI7-TI1,TI6-TI5, TI6-TI4,… TI6-TI1, …TI2-TI1)

E. Max difference from end: Maximum increase between any interval in the period and the last.
   Max(TI8-TI7, TI8-TI6, TI8-TI5, TI8-TI4, TI8-TI3, TI8-TI2, TI8-TI1)

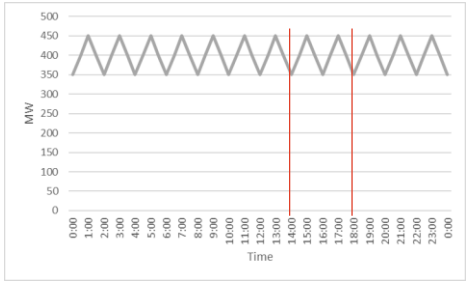
All options floored at zero.

Examples

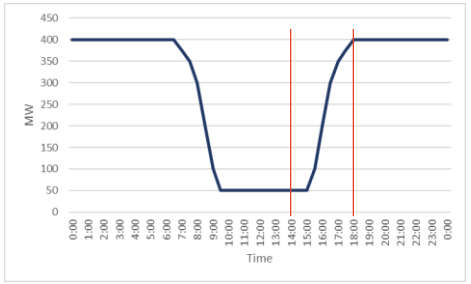
Site 1: Perfectly flat



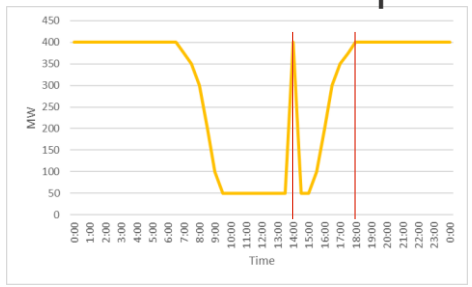
Site 2: Flat + volatile



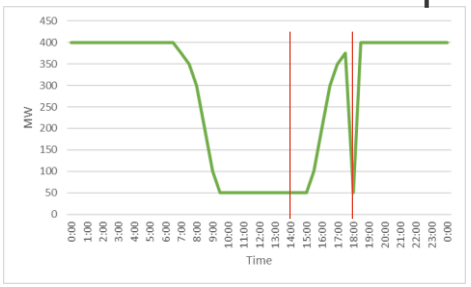
Site 3: PV



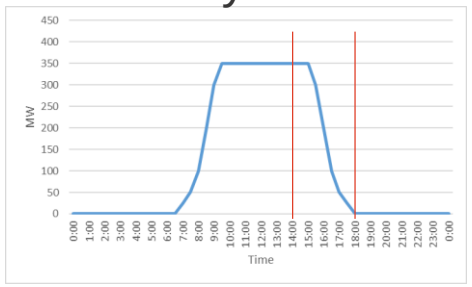
Site 4: PV + start spike



Site 5: PV + end dip



Site 6: Day demand



- Under A and B, site 4 has reduced its Flex IRCR to 0 without affecting the total MW ramp requirement.
- Under C, site 2 has almost the same IRCR as site 4.
- Under D, site 2 has some IRCR, but significantly less than sites 3, 4 and 5.
- Under E, site 5 has reduced its Flex IRCR to zero by significantly decreasing demand at the end of the ramp, which decreases the 4-hour ramp requirement

	Site 1	Site 2	Site 3	Site 4	Site 5	Site 6
A	0	0	350	0	0	0
B	0	0	43.8	0	0	0
C	0	50	58.3	100	65	0
D	0	100	350	350	325	0
E	0	0	350	350	0	0

Discussion

Method B has the same issue as the original. Method C advantages participants who increase over the whole period vs those who sawtooth within the period.

Method D is the most complex, and takes focus off the end of the ramp period.

Under Method E, a participant could still reduce its Flexible IRCR by correctly predicting the last interval of the IRCR period and reducing its demand in that interval. This behaviour could not be achieved using BTM PV, but could be achieved by briefly reducing load. In any case this change would actually help reduce the ramp requirement – spreading it over a longer period and potentially changing when the highest four-hour ramp occurs.

Flexible IRCR – Adjusted Method

1. For each Trading Interval in the previous Capacity Year, find the difference between the operational load at the end of the Trading Interval and the load at the end of the Trading Interval four hours prior.
2. Select the three Trading Days with the highest four-hour ramp value calculated under step 1.
3. For each Trading Day selected under step 2:
    a. select the Trading Interval with the largest value calculated under step 1; and
    b. select all Trading Intervals in the previous four hours.
4. For each participant load portfolio:
    a. calculate the portfolio ramp contribution for each Trading Interval selected in step 3, as the difference between consumption at the start of that Trading Interval and consumption at the end of the latest selected Trading Interval;
    b. Calculate the portfolio ramp contribution for each Trading Day selected in step 2 as the maximum portfolio ramp contribution identified under step 4a for Trading Intervals in that Trading Day.
    c. calculate the portfolio annual ramp contribution as the mean of the portfolio ramp contributions determined in step 4b.
5. Calculate scaling factor R as the RCR for flexible capacity divided by the sum of all portfolio annual ramp contributions.
6. For each participant load portfolio, set the flexible IRCR as the portfolio annual ramp contribution multiplied by the scaling factor.

6. Flexible Capacity refunds

Consultation paper Proposal P

The consultation paper proposed that capacity refunds for both Peak Capacity and Flexible Capacity would be paid from a single pool of capacity payments, with capacity refunds for Flexible Capacity capped at a set portion of total capacity revenues.

This was intended to avoid the incentive to meet Flexible Capacity obligations being weaker than the incentive to meet Peak Capacity obligations.

Response to submissions

Participants noted potential issues with using a single refund pool:

- Peak Capacity is needed at the beginning of the Capacity Year, but Flexible Capacity is likely to be needed towards the end of the Capacity Year. If a facility fails to meet its capacity obligations at the beginning of the Capacity Year and must refund all reserve capacity payments to zero, it may have no incentive to provide capacity for the rest of the year.
- Separate refund pools would prevent refunds from one capacity type from eating into refunds for the other type. This would increase the incentive to provide the other product for the rest of the Capacity Year.
- Having a single refund pool would mean it was not possible to rebate collected refunds to facilities that met capacity obligations (as currently) or to the customers who funded the capacity (as under Proposal S).

These points – particularly the final one – are compelling, and so rule drafting will proceed on the basis that capacity refunds for Peak Capacity and Flexible Capacity will be paid from separate capacity payment pools.

7. DSP capacity certification approach

Consultation Paper Proposal G

The consultation paper proposed that two methods for DSP certification be used:

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

Some submitters were concerned about the implementation complexity of having two assessment regimes. One submitter noted the potential complexity in assessing which approach a given aggregation would be subject to.

EPWA considered having all DSPs nominate their own CRC, thus giving all proponents incentive to “overfill the programme” to ensure sufficient curtailment would be available. While this is possible for aggregations, it is not so for large industrial sites which do not have a concept of aggregation. The main driver is not so much whether the Associated Loads stay constant from year to year, but rather whether the DSP is an aggregation or not.

Adjusted proposal

DSPs comprised of a single Associated Load will be allocated CRC based on the IRCR of the Associated Load less its minimum load requirement.

DSPs comprised of more than one Associated Load will be allocated CRC based on their nominated response.

This strikes a balance between certainty for large single loads and flexibility for aggregations, and reduces the overall implementation complexity.

8. DSP dispatch commitment

Consultation Paper Proposal J

Part of proposal J was to consider reducing the number of hours that DSPs can be dispatched from the current 200 hours per year, and the consultation asked respondents for their thoughts on this.

Several submissions supported reducing the total number of hours which a DSP can be dispatched, stating that this is a major barrier to more DSPs entering the market. Submitters proposed various changes to DSP requirements:

- One submitter considered that the current dispatch notice period (two hours) is too short and creates a barrier to many providers.
- One submitter proposed that the duration requirement could be reduced from 200 to 4 hours.
- One submitter proposed that DSP availability hours be based on the historical dispatch of DSPs, plus a margin.

EPWA considers that a historical DSP dispatch is not necessarily a good indicator of future dispatch, but that a minimum dispatch requirement related to the expected load duration curve could be appropriate.

LDC assessment

Currently DSPs hold 86 MW of CCs.

CY23 10% POE peak is 4,055 MW.

CY23 10% POE peak less DSPCCs is 3,969 MW.

CY23 50% POE peak is 3,790 MW.

CY23 90% POE peak is 3,551 MW.

CY scaled LDC	Hrs > 3,969	Hrs > 3,790	Hrs > 3,551
2016	2	9	42
2017	2	3	15
2018	1	17	67
2019	2	4	14
2020	1	4	31

Using five historic year LDCs scaled to meet 2022 ESOO peak demand and total energy forecasts, we see that if DSPs were dispatched when demand is above the 90% POE peak, then in the 10% POE peak year they could expect to be dispatched for between 14 and 67 hours*.

The current 200-hour requirement is approximately equivalent to dispatching DSPs whenever demand goes above 3000MW.

A DSP dispatch expectation of 50 hours appears sufficient to allow DSPs to be dispatched whenever the demand exceeds the 90% POE peak. If the quantity of DSPCCs increases significantly, they would need to be available in more hours to maintain power system security and reliability.

This analysis could be carried out annually, or the dispatch requirement assessed during 5-year review activity.

* Note that 2018 had a relatively flat LDC.

9. DSP refund cap

Consultation Paper Proposal R

The consultation paper proposed to:

- Amend the Maximum Facility Refund for DSPs to include the DSM Reserve Capacity Security.
- DSPs which voluntarily surrender Capacity Credits during the Capacity Year will forfeit their DSM Reserve Capacity Security in proportion to the amount of the reduction.

One respondent submitted that the current DSP refund regime is sufficient to ensure capacity availability. EPWA maintains that the capital-light nature of DSPs means that additional measures (such as perennial DSP Reserve Capacity Security) are required to ensure incentives are present.

AEMO noted that drawing on Reserve Capacity Security is relatively involved and manual process.

Options to provide additional incentive for DSP availability

Four options for DSP refunds:

A. **Status quo**: If DSP refunds hit the point where they have already paid back all the capacity payments they will get for the year, stop charging them refunds.

B. **Consultation proposal**: If a DSP's refunds hit the point where they have already paid back all their capacity payments, draw on their DSP Reserve Capacity Security.

C. **Increased refund cap**: Leave DSP RCS as is. Set DSP maximum capacity refund amount to more than total capacity payments for the year. DSPs would need to post prudential security.

D. **Test failure refunds excluded from cap**: Leave DSP RCS as is. Leave capacity refund cap as is. If a DSP fails an RC test, it starts paying refunds until it passes a test, and those refunds are excluded from the refund cap. DSPs would need to post prudential security.

Option A means DSPs have limited downside for non-performance. Option B is not feasible. Option C could be seen as arbitrary, but using 25% would match the Reserve Capacity Security at risk. Option D would also need to be capped to avoid unlimited refunds.

10. General Business

11. Next Steps

Next Steps

- Information paper confirming outcome of phase 2 items
- Exposure draft part 1 (early August)
  - Planning criterion
  - BRCP
  - New flexible capacity product
  - IRCR (peak and flex)
  - RLM
  - Capability classes
- Exposure draft part 2
  - DSP CRC
  - Testing, Outages, and Refunds
  - Capacity rebates
- Questions or feedback can be emailed to energymarkets@dmirs.wa.gov.au

We're working for Western Australia.