Government of **Western Australia**
Energy Policy WA

Meeting Agenda

Meeting Title:	Market Advisory Committee
Date:	Tuesday 28 June 2022
Time:	9:30 AM – 11:30 AM
Location:	Online, via TEAMS.

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda	Chair	Noting	2 min
2	Meeting Apologies/Attendance	Chair	Noting	2 min
3	Minutes of Meeting 2021_05_17	Chair	Decision	2 min
4	Action Items	Chair	Noting	0 min
5	Market Development Forward Work Program	Chair/Secretariat	Discussion	2 min
6	Update on Working Groups			
	(a) AEMO Procedure Change Working Group	AEMO	Noting	0 min
	(b) RCM Review Working Group	Working Group Chair	Discussion	75 min
	(c) CAR Working Group	Working Group Chair	Discussion	30 min
7	Rule Changes			
	(a) Overview of Rule Change Proposals	Chair/Secretariat	Noting	0 min
8	General Business	Chair	Discussion	2 min
	Next meeting: Tuesday 23 August 2022			

Please note, this meeting will be recorded.

Government of Western Australia
Energy Policy WA

Minutes

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	17 May 2022
Time:	9:30am – 11:42am
Location:	Videoconference (Microsoft Teams)

Attendees	Class	Comment[1]
Sally McMahon	Chair	
Dean Sharafi	Australian Energy Market Operator (**AEMO**)	
Aditi Varma	Network Operator	Proxy for Zahra Jabiri
Genevieve Teo	Synergy	
Paul Keay	Small-Use Consumer Representative	
Noel Schubert	Small-Use Consumer Representative	
Geoff Gaston	Market Customer	
Timothy Edwards	Market Customer	
Patrick Peake	Market Customer	
Wendy Ng	Market Generator	
Jacinda Papps	Market Generator	
Rebecca White	Market Generator	
Paul Arias	Market Customer	
Peter Huxtable	Contestable Customer	
Noel Ryan	Observer appointed by the Minister	
Rajat Sarawat	Observer appointed by the Economic Regulation Authority (**ERA**)	

Also in Attendance	From	Comment
Dora Guzeleva	MAC Secretariat	Observer
Laura Koziol	MAC Secretariat	Observer
Shelley Worthington	MAC Secretariat	Observer

Also in Attendance	From	Comment
Richard Bowmaker	Robinson Bowmaker Paul (**RBP**)	Presenter
Ajith S~~c~~reenivasan	RBP	Observer
Grant Draper	Marsden Jacob Associates (**MJA**)	Presenter
Andrew Campbell	MJA	Observer

Apologies	From	Comment
Martin Maticka	Australian Energy Market Operator (**AEMO**)	
Patrick Peake	Market Customer	
Tim Robinson	RBP	
Zahra Jabiri	Western Power	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30am with an Acknowledgement of Country. The Chair reminded all that the role of the MAC is to advise the Coordinator and that any advice must consider the interest of the WEM, and reminded observers to raise any issues they have with official members. The Chair reminded members that she is available to meet members individually offline, noting she would be meeting with Mr Schubert and Mrs Papps. The Chair requested that members have their video enabled during meetings unless there were connection or bandwidth issues. The Chair reminded members the meetings will be recorded to assist with taking minutes. The Chair advised that her position as expert panel member on the WA Electricity Review Board remains current.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance and apologies as listed above.	
3	**Minutes of Meeting 2022_04_05** The MAC accepted the minutes of the 5 April meeting as a true record of the meeting. **Action: The MAC Secretariat to publish the minutes of the 5 April 2022 MAC meeting on the Coordinator's Website as final.**	**MAC Secretariat**
4	**Action Items** Mr Sharafi noted AEMO was unable to include any new prudential changes into the reform work program.	

Item	Subject	Action
	The Chair requested further information on the context of Mr Sharifi's statement. Mr Gaston noted that he had sent some information to Ms Guzeleva highlighting some concerns that he considered need to be addressed at a later stage, noting Ms Guzeleva had responded. The Chair advised these matters would be discussed offline to determine if they needed to be dealt with by the MAC.	
5	**Market Development Forward Work Program** The paper was taken as read and the Chair noted updates in red were to be reviewed and discussed. The following topics were discussed. • **The Reserve Capacity Mechanism Review Working Group** To be discussed in more detail later in the meeting. • **The Cost Allocation Review Working Group** • To be discussed in more detail later in the meeting. • **Item 22** The Chair noted action item 22, is closed, but if there is any residual issues, the MAC may have to look at a new item on those.	
6	**Update on Working Groups**	

	(a) AEMO Procedure Change Working Group (APCWG)
	The paper was taken as read. Mr Sharifi confirmed that there was no AEMO procedure change activity this month [May].
	(b) RCM Review Working Group (RCMRWG)
	The Chair noted that the recommendation in the paper is to note the Minutes of the last meeting and the actions in response to the MAC feedback at the last MAC meeting in April. The Chair to confirm with Ms Guzeleva that the updates to the Minutes have been adopted.
	The Chair advised the MAC to note the RCMRWG discussion on the initial results of the system stress modelling and noted that the meeting papers provide:
	• an update on the process to date
	• minutes of the last meeting
	• a presentation which presents the results, highlighting three main areas on which MAC feedback was being sought:
	  ○ should curtailed injection be part of a capacity mechanism?
	  ○ should ramping capability be part of a capacity mechanism?
	  ○ should a two-limbed planning criterion be retained?
	The Chair noted the papers were taken as read.
	Mr Bowmaker from RBP provided a presentation to facilitate discussion with the MAC, noting the appendix to the presentation circulated includes detailed modelling outputs from the modelling done to date.	

Item	Subject	Action
	Slide 3 The Chair requested further elaboration on the response to the RCMRWG feedback to ensure it had been captured in the way it was intended. Mr Bowmaker ran through the points on the slide, noting in particular that: • Point 2: a question has been raised whether various aspects of each of the system stress events can be solved through the RCM or left to the energy market and that there would be discussion on this moving forward. • Point 5: the team is happy to receive input on design directions, noting RBP is familiar with assessing projects for investors and will be incorporating into the design. The team would welcome input on any particular areas that may be difficult for investors. • Point 6: The WOSP that is currently available is fairly old and on a different basis to the Electricity Statement of Opportunities (**ESOO**) so inconsistency will occur if the two are combined. The purpose of the modelling is to forecast system stress events under different future demand and generation scenarios. RBP will continue using ESOO forecasts and projecting those forward beyond the ESOO horizon. • Mr Schubert sought to clarify whether the ESOO being used was last years, noting there was a new one coming out in June. • Mr Bowmaker confirmed that was correct. Slide 4 • Mr Bowmaker noted the modelling is still ongoing and will be refined on with a Monte Carlo simulation to improve accuracy. The team is now looking for the MAC to provide guidance on those preliminary design options as indicated on each issue, noting some of those initial decisions may need to be revisited in later stages. Slide 6 • Initial system stress modelling has been conducted which is feeding into analysis on the required capacity services going forward. RBP will be moving into the economic modelling to look at the impacts of Certified Reserve Capacity (**CRC**) allocation and Benchmark Reserve Capacity Price (**BRCP**) options and how that affects future capacity mix. • Ms White noted an action from RCMWG was for RBP to do some further modelling that better captured peak events. • Mr Bowmaker responded that RBP would incorporate more of a Monte Carlo simulation approach to the modelling going forward, avoiding averaging and instead using individual historical load shapes and multiple modelling iterations to better capture peaks and ramping events.	

Slide 8

- Mr Bowmaker noted the characteristics of capacity that would be needed based on the modelling as per the slide.
- The Chair clarified that 'significant capacity to balance generation' referred to the technologies that are actually able to help with the problem of having high levels of intermittent or non-scheduled generation, noting that this goes to whether or not the market needs to value the different characteristics of different technology.

Slide 9

- Mr Bowmaker noted that one of the key issues is whether it should it be the role of the new RCM to deal with the issue of minimum demand and, if so, what are the metrics that could be used.
- Mr Schubert referred to discussions in the November 2021 MAC meeting noting there is a lot of flexible load that is not incentivized to turn on during periods of low demand. Market mechanisms should ensure flexible demand turns on in a low demand situation, with curtailment of renewable energy used as a last resort.
- The Chair noted that this will be covered by the review and asked Mr Schubert to check whether the recommendation is consistent with that view or whether another issue needs to be captured as a supporting assumption.

Slide 10

- Mr Bowmaker noted the general agreement in the RCMRWG and that Low load is an issue that needs to be addressed and dealt with through real time activity rather than having a separate curtailed injection as a product within the RCM.

Slide 11

- Mr Bowmaker noted the preliminary direction was that curtailed injection will not be included in the RCM and asked whether the MAC agreed with that preliminary direction.
- Mr Huxtable noted that building flexibility into demand side assets typically requires long lead times and capital expenditure because they are usually sized to be fit for purpose.
- Mr Bowmaker noted there were two tranches of demand response: what is existing and can be used without a lot of capital expenditure and major projects with longer lead times that can add this flexible demand.
- The Chair noted the preliminary direction is that the RCM does not need to deal with the issue of curtailed injection because there are more effective ways of dealing with it and there are work programs in place that are addressing it.
- Mr Schubert noted that, provided other market mechanisms incentivize flexible loads to consume during low load periods, that position is acceptable but that Mr Huxtable's point on capital expenditures is very valid for large scale projects and that

Item	Subject	Action
	commercial signals were not getting through to customers with existing demand flexibility. • The Chair reiterated that the focus of this point in the discussion was to get agreement that having curtailment of injection excluded from the RCM at this stage is not viewed as a problem by the MAC, noting other work may address this. • Mr Sharafi agreed the focus of the RCM review should not be dealing with the low load issues but that if, through this work, there are opportunities identified that also address some of these issues it was beneficial to recognise them. • The Chair requested that RBP captures that these issues are being raised and it is understood that they are addressed elsewhere. • Ms White noted her feedback to the RCMRWG was that it is important to consider low load in some manner and that this preliminary direction should be open to change later in the project if new information justifies this. Ms White noted that while it can be useful to narrow the scope and have decision gates to help focus the work, if it later turns out that issues need reconsideration then change should be considered. Additionally, on out of scope issues, the WEM is interwoven and not looking at the flow on effects as part of the project is a risk and therefore consideration should be given to whether out of scope items will need to be reopened in the interest of ensuring the market design works as a whole. • Ms Guzeleva noted that time was of the essence due to the need to make changes as soon as possible to ensure power system security in the context of the RCM's long lead times. Given this, it would be counterproductive to reopen the scope and miss the opportunity to make changes, and issues would be logged as they arise. She also noted that the participation of flexible loads in the energy market needs a broader review. • The Chair agreed with Ms Guzeleva that an element of pragmatism was required due to the need to keep moving forward, noting that it was not out of the question to revisit something if it was required but that each review will not be able to address every issue. Slide 12 • Mr Bowmaker continued with design options to achieve investment in capacity products sufficient to meet ramping needs, including the options to integrate ramping capability in the RCM or to procure it as an Essential Systems Service (**ESS**) (as per the slide)	

Slide 13

- Mr Bowmaker noted that there was mixed feedback from the RCMWG as to whether flexibility should be incorporated in the RCM or not.

Slide 14

- The team has not come to a conclusion on ramping as the economic modelling is to provide insight into what sort of capacity is expected to be introduced into the market as a result of the reformed RCM.
- Ms Varma noted that AEMO is procuring about 100 megawatts of fast ramping or fast frequency response service through the Non-Co-optimised ESS (**NCESS**) framework and sought to clarify if that will feature in the modelling to see whether 100 megawatts will be sufficient to respond to the “duck’s neck”. Ms Varma noted the significance of needing to delineate between capacity that is capable of ramping quickly and the service of providing fast ramping. She suggested that the concept of the RCM procuring capacity for a future service provision should be front and center in the working group's minds to ensure there is the right type of capacity coming in to deal with ESS issues.
- Mr Bowmaker noted the modelling will incorporate all the ESS requirements and that, in assessing the issue going forward, there would be delineation between the planning aspect and the operational aspect of ramping. Mr Bowmaker noted that the purpose of the modelling is to look at that planning time frame to determine whether the RCM market, as currently anticipated, provides sufficient fast ramping capacity or whether the design needs to be altered to ensure there is sufficient ramping capacity entering the market.
- Ms Ng noted that she did not want existing facilities to be required to have fast ramping capability and demonstrate that as part of a CRC allocation process as this could require significant capital expenditure. Ms Ng agreed there was an issue that needed to be looked at but the two should not be linked together.
- The Chair noted that this was another issue of integration between the RCM and ESS markets. The Chair considered what other encouragement methods might be available and asked how distracting would be for this review to actually think about that as an add-on.
- Mr Schubert agreed with Ms Ng’s comment noting that, technically, it was possible for some assets in the existing fleet to provide fast ramping. He added that there are currently only a few units doing load following which would require the dispatch of more units to cope with the fast ramping. Mr Schubert provided an example of markets where all units have to contribute to fast response and ramping, noting that a way this could be achieved would be to allow generators to only run up to 95% of their

Item	Subject	Action
	capacity, leaving 5% of headroom for them to respond to the need to ramp quickly, but this would have economic implications. • Ms Guzeleva noted that the methods for assigning CRC will be assessed as part of the RCM Review and that looking at whether different types of capacity with different characteristics should be renumerated differently in the capacity mechanism was in scope. • Mrs Papps noted that additional investments may be needed to enable gas fired power plants' fast-ramping capabilities. Mrs Papps considered that the ESS markets ~~will~~ may not be sufficient to incentivise this investment. • Mr Sharafi noted that he considered ramping should be included in the RCM review., AEMO has seen ramping requirements this year almost double (compared to last year), so ramping capability should be the focus of this work. • The Chair noted that the comments highlight that the issue is what the role of the RCM is and whether planning or operational horizons are the focus of this work and how these two different horizons can be best addressed. • Ms Varma expanded further on her previous comment to highlight that longer term investment signals that ensure that the right capacity will enter the market and be ready to participate when it is needed in operational horizons are important. • Mr Bowmaker noted that ramping is becoming quite an issue in the near term. Part of the modelling will provide insight into whether the new RCM will incentivise new capacity that will provide sufficient ramping capability. Modelling may indicate there does need to be additional measures within the RCM to ensure that there is sufficient ramping capability over the modelling horizon. Slide 16 – Planning criterion • Mr Bowmaker noted that there are many ways to measure reliability and noted some options for the WEM as per the slide. Slide 17 – Aspects of the current peak load component • Mr Bowmaker noted that some aspects are not fit for purpose at the moment, as per the slide, and that these elements will be considered as part of the options analysis. Slide 18 – Planning criterion – WG feedback • Mr Bowmaker noted that there was support from the RCMRWG for retaining a two-limbed planning criterion and for further assessment of what the different options are. • It was generally agreed that unserved energy is clearly important., However, there is distinction between a large number of small outages or one very deep outage that also needs to be captured as part of the criterion.	

Slide 19

- Mr Bowmaker noted that, as part of the modelling going forward, the team will be looking at how different planning criteria effect the capacity target and system reliability and was seeking the MAC feedback on that direction.
- Mr Schubert supported retaining a two-limbed planning criterion noting that further modelling will give the MAC more information. Mr Schubert intuitive preference was for retaining peak load in the criterion because it was easy for everyone to understand what that means.
- Ms Varma noted that there was a third arm, which is about having enough capacity to meet contingency events and sought to clarify how that was included in the modelling.
- Mr Bowmaker noted that this will be incorporated into the modelling.
- Ms Varma noted that historically the unserved energy limb of the planning criteria has been the determining factor but carrying enough capacity to meet spinning reserve requirements is becoming increasingly important and the framework needs to ensure that the planning criteria can trigger investments to meet both limbs.
- Mr Bowmaker noted that this is one of the things the team will be looking at as it refines tits recommendations in this area.
- Mrs Papps agreed with the preference to retain the two-limbed planning criterion. She noted that if it was just peak demand that would potentially undervalue the assets that contribute during other periods of system stress. Mrs Papps noted that working out how a generator contributes to reducing the expected unserved energy could be quite complex and that we would want to avoid the planning criterion resulting in an overengineered certification criteria. Mrs Papps noted that one of the key concerns around the RCM at the moment is that it is really difficult to explain to boards and financiers and, therefore, what is chosen for the planning criterion should be kept as simple as possible.
- Mr Sharafi noted the importance of the RCM addressing both adequacy and security.
- The Chair noted that the MAC supports the recommendations with further work to assess the planning criterion.

Slide 20 – approach to revising the planning criterion

- Mr Bowmaker noted that this slide would be taken as read.

Slide 22 – next steps

- Mr Bowmaker talked through the slide.
- Mr Sharafi mentioned the outcome of the 10 May meeting that AEMO had with the team, noting AEMO would like to see:
    - more granularity of the results;
    - ESS requirement over the shorter-term (2025-2030);

Item	Subject	Action

- further details about the modelling of system strength, inertia and fault current;
- additional scenarios to capture more detail about how the transition will be addressed;
- reassurance that extreme conditions will not be lost through averaging in the modelling.

- Mr Sharafi noted that the discussion regarding ramping and ESS is valid and that, from an AEMO perspective, the RCM review is designed to address not only adequacy but also system security issues and AEMO would like to see system stress situations addressed in the modelling.
- Mr Schubert supported Mr Sharafi's comments.
- Mr Bowmaker thanked the MAC members for their feedback.

(c) CAR Working Group (CARWG)

The paper was taken as read.

Chair of the CARWG, Ms Guzeleva, addressed the MAC noting;

- The Cost Allocation Review (**CAR**) focuses on two groups of costs not fully examined through the work of the Taskforce: cost of regulation and the cost of the market fees, and how these should be allocated to market participants.
- The first meeting of the CARWG was held on Monday 9 May.

Slide 3

- Ms Guze~~a~~leva outlined the guiding principles of the review noting that, where a causer can be identified, the causer pays principle would be applied subject to also meeting all of the other guiding principles.
- Ms Guze~~a~~leva encouraged members to continue to go back to these principles as she is aware that members of the Working Group have some very strong views of what costs should be allocated where from the outset.

Slide 4 - 5

- Mr Draper from Marsden Jacob Associates (**MJA**) provided an overview of what was in scope for this Review as per the slides

Slide 6

- Mr Draper noted that the team will begin working with the Working Group on assessing the extent to which the current allocation methods are consistent with the causer pays principle and whether there are opportunities to improve cost allocation.
- Following this the team will do practicality assessments, which will include analysing the financial implications of different options and assessing the equity and efficiency consequences.
- The review will recommend a preferred approach to cost allocation and implementation and develop a methodology and formal rule changes, if required.

Item	Subject	Action
	Slide 8 – 9 • Mr Draper noted that stakeholder engagement will occur as per the slides. Slide 11 • Mr Draper noted there are not many examples of cost allocation methodologies using a causer pays principle in the energy sector. MJA has looked at work done by the Independent Pricing and Regulatory Tribunal (IPART) on allocating water, disaster and local land services costs, which provides a framework for cost allocation that is relevant to this review. • Mr Draper ran through the elements of the framework on the slide and noted that a key consideration will be whether charging a 'causer' prompts an efficient response that reduces costs as this is key to achieving efficiency. • Mr Draper noted that allocating costs to taxpayers is out of scope. Slide 12 • Mr Draper ran through the content on the slide, noting in particular that the State Government is a causer/beneficiary of costs through policy changes or other interventions. • Mr Sharafi suggested two principles should be followed: clarity and flexibility. Clarity being important in the identification of causers and beneficiaries, so the cost can be allocated appropriately, noting that a causer or beneficiary must be a market participant to enable costs being allocated to them. Flexibility is important where it's not clear who the causer or beneficiary is – in this case some practicality will need to be applied and an 80/20 rule could be adopted. • Mr Draper agreed sensibility and balance were required when it came to allocating costs – requirements for full activity-based costing to guide cost allocation would not necessarily be efficient. Slide 14 - 18 • Mr Draper advised that MJA is reviewing cost allocation methods in other jurisdictions and provided some early feedback from this as per the slides, noting reforms implemented in the UK would be more difficult to implement here due to metering arrangements. Slide 19 -20 • Mr Draper noted CARWG feedback and response as per the slide. • The Chair sought to clarify what would be useful for the MAC to provide at this time. • Ms Guzeleva noted that there had been discussions on looking outside of this review into things like retail tariffs and whether costs should be allocated to the government. Ms Guzeleva advised that EPWA is seeking for MAC to confirm the original scope of works, which is focusing on the market and market	

Item	Subject	Action
	participants, and on costs that have not recently been reviewed; namely regulation and market fees, both of which are currently charged at a flat rate per MWh on both sides of the market. • The Chair noted that Ms Guzeleva was seeking to clarify that MAC was supportive of settling the fees and charges to be included in the review, as well as which parties would be eligible to contribute to these costs. • Mrs Papps sought to make sure that the costs associated with some non-business as usual (**BAU**) policy projects are borne by the correct, limited group of beneficiaries and causers. For example: the implementation of the Distributed Energy Resources roadmap is caused by and benefits rooftop solar customers; and Project Symphony only benefits Synergy at the moment rather than market aggregators because of its exclusive access to franchise customers. • Mr Draper noted that point 4 on slide 20 addresses this matter, noting that this was in scope for this review. • Mr Arias and Ms White noted they support Ms Papp's comments. • The Chair agreed that it would be important to identify discrete services and allocate costs appropriately. • Mr Schubert noted that at the CARWG meeting it was requested that MJA assess the causers and beneficiaries with more granularity and noted an example of allocating costs associated with volatility to intermittent generation. • Ms Draper noted that MJA would take this into account. • Ms Varma noted that it was important to ensure that drivers of fee allocation are understood and explored. Historically, it appears in the WEM that the fees have been allocated based on AEMO effort in administering the market and this was expanded to include the Coordinator as well. Ms Varma noted that she did not consider behaviour modification was ever the objective of the allocation.	
7	**Rule Changes**	
	(a) Overview of Rule Change Proposals The paper was taken as read.	
8	**General Business** • The Chair noted the letter Ms White had sent to Ms Guzeleva and the Chair regarding the RCM review which will be taken into account as part of that review. • Updates to the schedule of MAC meetings were agreed.	

The meeting closed at 11:42 am.

Government of **Western Australia**
Energy Policy WA

Agenda Item 4: MAC Action Items

Market Advisory Committee (**MAC**) Meeting 2022_06_28

Shaded	Shaded action items are actions that have been completed since the last MAC meeting. Updates from last MAC meeting provided for information in RED.
Unshaded	Unshaded action items are still being progressed.
Missing	Action items missing in sequence have been completed from previous meetings and subsequently removed from log.

Item	Action	Responsibility	Meeting Arising	Status
1/2022	MAC Secretariat to publish the minutes of the 17 May 2022 MAC meeting on the Coordinator's Website as final.	MAC Secretariat	2022_05_17	**Closed** The minutes were published on the Coordinator's Website on 18 May 2022.

Government of **Western Australia**
Energy Policy WA

Agenda Item 5: Market Development Forward Work Program

Market Advisory Committee (**MAC**) Meeting 2022_06_28

1. Purpose

- To provide an update on the Market Development Forward Work Program provided in Table 1, including:
  - the Chair of the Reserve Capacity Review Working Group (**RCMRWG**) is to update the MAC on the progress by the Working Group– see Agenda Item 6(b); and
  - the Chair of the Cost Allocation Review Working Group (**CARWG**) is to update the MAC on the progress by the Working Group– see Agenda Item 6(c).
- To provide an update on other issues to be addressed via the Market Development Forward Work Program provided in Table 4:
  - No updates.
- Changes to the Market Development Forward Work Program provided at the previous MAC meeting are shown in red font in the Tables below.

2. Recommendation

The MAC Secretariat recommends that the MAC notes the updates to the Market Development Forward Work Program.

3. Process

Stakeholders may raise issues for consideration by the MAC at any time by sending an email to the MAC Secretariat at energymarkets@energy.wa.gov.au.

Stakeholders should submit issues for consideration by the MAC two weeks before a MAC meeting so that the MAC Secretariat can include the issue in the papers for the MAC meeting, which are circulated one week before the meeting.

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
RCM Review	A review of the RCM, including a review of the Planning Criterion.	• The MAC has established the RCM Review Working Group. Information on the Working Group is available at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group, including: ○ the Scope of Works for the review, as approved by the Coordinator; ○ the Terms of Reference for the Working Group, as approved by the MAC; ○ the list of Working Group members; ○ meeting papers and minutes from the Working Group meeting on 20 January 2022 and 17 February 2022; ○ meeting papers for the Working Group meeting on 17 March 2022, 5 May 2022; ○ meeting papers and minutes from the Working Group meeting on 2 June 2022; and ○ meeting papers from the Working Group meeting on 16 June 2022. • The Chair of the Working Group will update the MAC on the work done by the Working Group to date. The Chair will update the MAC on the initial results of the system stress modelling – see Agenda Item 6(b).
Cost Allocation Review	A review of: • the allocation of Market Fees, including behind the meter (**BTM**) and Distributed Energy Resources (**DER**) issues; • cost allocation for Essential System Services; and	• The MAC has established the Cost Allocation Review Working Group. Information on the Working Group is available at https://www.wa.gov.au/government/document-collections/cost-allocation-review-working-group, including: ○ the Scope of Work for the review, as approved by the Coordinator; ○ the Terms of Reference for the Working Group, as approved by the MAC; and

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
	• Issues 2, 16, 23 and 35 from the MAC Issues List (see Table 3).	○ the list of Working Group members; and ○ meeting papers and minutes from the Working Group meeting on 9 May 2022; and ○ meeting papers from the Working Group meeting on 7 June 2022. • EPWA has engaged Marsden Jacob Associates for the consultancy services to assist with the Cost Allocation Review. • The Chair will update the MAC on the Working Group's progress to date – see Agenda Item 6(c).
Procedure Change Process Review	A review of the WEM Procedure Change Process to address issues identified through Energy Policy WA's consultation on governance changes.	• This review will commence in mid-2022. ○ No update.
Forecast quality	Review of Issue 9 from the MAC Issues List (see Table 4).	• This review has been deferred.
Network Access Quantity (**NAQ**) Review	Assess the performance of the NAQ regime, including policy related to replacement capacity, and address issues identified during implementation of the Energy Transformation Strategy (ETS).	• This review will be commenced after completion of the RCM Review.
Short Term Energy Market (**STEM**) Review	Review the performance of the STEM to address issues identified during implementation of the ETS.	• This review has been deferred.

Table 2 – Issues to be Addressed in the RCM Review			
Id	**Submitter/Date**	**Issue**	**Status**
1	Shane Cremin November 2017	**IRCR calculations and capacity allocation** There is a need to look at how IRCR and the annual capacity requirement are calculated (i.e. not just the peak intervals in summer) along with recognising BTM solar plus storage. The incentive should be for retailers (or third-party providers) to reduce their dependence on grid supply during peak intervals, which will also better reflect the requirement for conventional 'reserve capacity' and reduce the cost per kWh to consumers of that conventional 'reserve capacity'.	To be considered in the RCM Review.
3	Shane Cremin November 2017	Penalties for outages.	To be considered in the RCM Review.
4	Shane Cremin November 2017	Incentives for maintaining appropriate generation mix.	To be considered in the RCM Review.
14/36	Bluewaters and ERM Power November 2017	**Capacity Refund Arrangements:** The current capacity refund arrangement is overly punitive as Market Participants face excessive capacity refund exposure. This refund exposure is well more than what is necessary to incentivise the Market Participants to meet their obligations for making capacity available. Practical impacts of such excessive refund exposure include: • compromising the business viability of some capacity providers – the resulting business interruption can compromise reliability and security of the power system in the SWIS; and • excessive insurance premiums and cost for meeting prudential support requirements.	To be considered in the RCM Review.

Table 2 – Issues to be Addressed in the RCM Review			
Id	**Submitter/Date**	**Issue**	**Status**
		Bluewaters recommended imposing seasonal, monthly and/or daily caps on the capacity refund. Bluewaters considered that reviewing capacity refund arrangements and reducing the excessive refund exposure is likely to promote the Wholesale Market Objectives by minimising: • unnecessary business interruption to capacity providers and in turn minimising disruption to supply availability; which is expected to promote power system reliability and security; and unnecessary excessive insurance premium and prudential support costs, the saving of which can be passed on to consumers.	
30	Synergy November 2017	**Reserve Capacity Mechanism** Synergy would like to propose a review of WEM Rules related to reserve capacity requirements and reserve capacity capability criteria to ensure alignment and consistency in determination of certain criteria. For instance: • assessment of reserve capacity requirement criteria, reserve capacity capability and reserve capacity obligations; • IRCR assessment; • Relevant Demand determination; • determination of NTDL status; • Relevant Level determination; and • assessment of thermal generation capacity. The review will support Wholesale Market Objectives (a) and (d).	To be considered in the RCM Review.

Table 2 – Issues to be Addressed in the RCM Review			
Id	**Submitter/Date**	**Issue**	**Status**
56	Perth Energy July 2019	**Issues with Reserve Capacity Testing** • Market Generators that fail a Reserve Capacity Test may prefer to accept a small shortfall in a test (and a corresponding reduction in their Capacity Credits) than to run a second test. • There is a discrepancy between the number of Trading Intervals for self-testing vs. AEMO testing. • There is ambiguity in the timing requirements for a second test when the relevant generator is on an outage. There is ambiguity on the number of Capacity Credits that AEMO is to assign when certain test results occur.	To be considered in the RCM Review (except that the first bullet may be out scope, in which case it will be added to Table 4).
58	MAC October 2019	**Outage scheduling for dual-fuel Scheduled Generators** '0 MW' outages are currently used to notify System Management when a dual-fuel Scheduled Generator is unable to operate on one of its nominated fuels. There is no explicit obligation in the WEM Rules or the Power System Operation Procedure: Facility Outages to request/report outages that limit the ability of a Scheduled Generator to operate using one of its fuels. In terms of the provision of sent out energy (the service used to determine Capacity Cost Refunds), it is questionable whether this situation qualifies as an outage at all. More generally, the WEM Rules lack clarity on the nature and extent of a Market Generator's obligations to ensure that its Facility can operate on the fuel used for its certification, what (if anything) should occur if these obligations are not met, and the implications for outage scheduling and Reserve Capacity Testing. • (See section 7.2.2.5 of the Final Rule Change Report for RC_2013_15.)	To be considered in the RCM Review (or may be out of scope, in which case it will be added to Table 4).

Table 3 – Issues to be Addressed in the Cost Allocation Review			
Id	**Submitter/Date**	**Issue**	**Status**
2	Shane Cremin November 2017	Allocation of market costs – who bears Market Fees and who pays for grid support services with less grid generation and consumption?	To be considered in the Cost Allocation Review.
16	Bluewaters November 2017	BTM generation is treated as reduction in electricity demand rather than actual generation. Hence, the BTM generators are not paying their fair share of the network costs, Market Fees and ancillary services charges. Therefore, the non-BTM Market Participants are subsiding the BTM generation in the WEM. Subsidy does not promote efficient economic outcome. Rapid growth of BTM generation will only exacerbate this inefficiency if not promptly addressed. Bluewaters recommends changes to the WEM Rules to require BTM generators to pay their fair share of the network costs, Market Fees and ancillary services charges. This is an example of a regulatory arrangement becoming obsolete due to the emergence of new technologies. Regulatory design needs to keep up with changes in the industry landscape (including technological change) to ensure that the WEM continues to meet its objectives. If this BTM issue is not promptly addressed, there will be distortion in investment signals, which will lead to an inappropriate generation facility mix in the WEM, hence compromising power system security and in turn not promoting the Wholesale Market Objectives.	To be considered in the Cost Allocation Review.
23	Bluewaters November 2017	Allocation of Market Fees on a 50/50 basis between generators and retailers may be overly simplistic and not consider the impacts on economic efficiency. In particular, the costs associated with an electricity market reform program should be recovered from entities based on the benefit they receive from the	To be considered in the Cost Allocation Review.

Table 3 – Issues to be Addressed in the Cost Allocation Review			
Id	**Submitter/Date**	**Issue**	**Status**
		reform. This is expected to increase the visibility of (and therefore incentivise) prudence and accountability when it comes to deciding the need and scope of the reform. Recommendations: to review the Market Fees structure including the cost recovery mechanism for a reform program. The cost saving from improved economic efficiency can be passed on to the end consumers, hence promoting the Wholesale Market Objectives.	
35	ERM Power November 2017	**BTM generation and apportionment of Market Fees, ancillary services, etc.** The amount of solar PV generation on the system is increasing every year, to the point where solar PV generation is the single biggest unit of generation on the SWIS. This category of generation has a significant impact on the system and we have seen this in terms of the daytime trough that is observed on the SWIS when the sun is shining. The issue is that generators that are on are moving around to meet the needs of this generation facility but this generation facility, which could impact system stability, does not pay its fair share of the costs of maintaining the system in a stable manner. That is, they are not the generators that receive its fair apportionment of Market Fees and pay any ancillary service costs but yet they have absolute freedom to generate into the SWIS when the fuel source is available. There needs to be equity in this equation.	To be considered in the Cost Allocation Review.

Table 4 – Other Issues			
Id	**Submitter/Date**	**Issue**	**Status**
9	Community Electricity November 2017	Improvement of AEMO forecasts of System Load; real-time and day-ahead.	Consideration of this issue has been deferred.

MARKET ADVISORY COMMITTEE MEETING, 28 June 2022

FOR NOTING

SUBJECT: UPDATE ON AEMO'S MARKET PROCEDURES

AGENDA ITEM: 6(A)

1. PURPOSE

Provide a status update on the activities of the AEMO Procedure Change Working Group and AEMO Procedure Change Proposals.

2. AEMO PROCEDURE CHANGE WORKING GROUP (APCWG)

	Most recent meetings	Next meeting
Date	30 November 2021	TBC
Market Procedures for discussion	Market Procedure: Prudential Arrangement	TBC

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as at 28 June 2022. Changes since the previous MAC meeting are in red text. A procedure change is removed from this report after its commencement has been reported or a decision has been taken not to proceed with a potential Procedure Change Proposal.

ID	Summary of changes	Status	Next steps	Indicative Date
None				

Government of Western Australia
Energy Policy WA

Agenda Item 6(b): Update on the RCM Review Working Group

Market Advisory Committee (**MAC**) Meeting 2022_06_28

1. Purpose

- The Chair of the Reserve Capacity Review Working Group (**RCMRWG**) is to update the MAC on the activities of the RCMRWG since the last MAC meeting.
- The MAC is to:
  - note the further results of the system stress modelling; and
  - provide guidance to the RCMRWG on the proposed direction and options for the Planning Criterion and the methodology for assigning for Certified Reserve Capacity (**CRC**).

2. Recommendation

That the MAC:

(1) notes the minutes from the RCMRWG meetings on 5 May 2022 and 2 June 2022;

(2) note the resulting actions and responses regarding the MAC's feedback at previous meetings (slides 41 to 43);

(3) notes the update on the RCMRWG meetings on 2 and 16 June 2022, including its feedback on:

 (a) the further modelling results;

 (b) the review of the Planning Criterion including proposals to include an additional limb in the Planning Criterion to account for the need of flexible capacity; and

 (c) options for the methodology(s) for assigning CRC.

(4) provides guidance to the RCMRWG on the matters outlined in the slides, including:

 (a) does the MAC agree with the RCMRWG's recommendation to retain the two existing limbs of the Planning Criterion: peak load and EUE (slide 11);

 (b) does the MAC agree with the RCMRWG's recommendation that the reserve margin definition should be changes ahead of the rest of the RCM (slide 13);

 (c) does the MAC agree with the RCMRWG's recommendation to compare a continuation of the current single-product RCM with a two-product RCM with separate targets for peak capacity and flexible capacity (slide 16);

 (d) does the MAC agree with the RCMRWG's recommendation to set a flexible capacity target based on the steepest ramp (slide 18);

 (e) does the MAC agree with the MAC Secretariat's proposed treatment of curtailed intermittent generation in the flexible capacity target (slide 18);

(f) does the MAC agree with the MAC Secretariat's proposal to replace the availability classes with new capability classes (slide 19);

(g) does the MAC agree with the RCMRWG's recommendation to have targeted availability obligations (slide 20);

(h) does the MAC agree with the RCMRWG's recommended options for assessing CRC allocation (slide 23); and

(i) does the MAC have any comments or questions on the installed capacity (**ICAP**) vs unforced capacity (**UCAP**) assessment (slide 25)?

3. Process

- Outcomes from the 5 May 2022 RCMRWG meeting were presented at the 17 May 2022 MAC meeting, when the MAC:
  - discussed the initial results of the system stress modelling and the RCMRWG's feedback on these results; and
  - supported the preliminary directions, including:
    - to not include curtailment injection in the Reserve Capacity Mechanism;
    - to undertake further modelling to assess whether the fleet is likely to have sufficient ramp capability or whether options should be developed for the CRC allocation methodologies to encourage ramping capability; and
    - that a two-limbed Planning Criterion should be retained, and that modeling should be undertaken of the available options and their effect on the Reserve Capacity Target and system reliability.

  Minutes from the 5 May 2022 RCMRWG meeting are attached (**Attachment 1**)
- On 2 June 2022, the RCMRWG discussed options for assigning CRC to facilities and for addressing the need for flexibility in the RCM (see **Attachment 2** for the minutes of this meeting).
- On 16 June 22, the RCMRWG discussed further results of the system stress modelling, the implications of the results on the Planning Criterion, and options for the Planning Criterion, including:
  - retaining a 'peak capacity product' with a two-limbed Planning Criterion similar to the existing criterion; and
  - developing a new 'flexible capacity product' and a separate Planning Criterion for this product.
- **Attachment 3** provides a summary of the outcomes from the 2 and 16 June 2022 RCMRWG meetings. Attachment 3 will be taken as read at the MAC meeting on 28 June 2022 and only the key results from the RCMRWG meetings will be presented. The purpose of this presentation is to:
  - inform MAC of the further outcomes of the system stress modelling;
  - provide an opportunity for MAC to provide guidance on the directions supported by the RCMRWG (see recommendation (4) above and slides 34-37); and
  - provide an opportunity for MAC to comment on the proposed assessment of the installed capacity (**ICAP**) and unforced capacity (**UCAP**) regimes for the SWIS;
  - update the MAC on the project timeline and next steps.

Further information on the RCM Review is available on the RCM Review webpage at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group.

4. Attachments

(1) RCMRWG 2022_05_05 – Minutes of Meeting

(2) RCMRWG 2022_06_02 – Minutes of Meeting

(3) Reserve Capacity Mechanism Review Slides – MAC Update

Government of **Western Australia**
Energy Policy WA

Minutes

Meeting Title:	Reserve Capacity Mechanism Review Working Group (**RCMRWG**)
Date:	5 May 2022
Time:	9:30am – 11:30am
Location:	Microsoft TEAMS

Attendees	Company	Comment
Laura Koziol	Chair	Proxy for Dora Guzeleva
Paul Arias	Bluewaters Power	
Rhiannon Bedola	Synergy	
Manus Higgins	AEMO	
Peter Huxtable	Water Corporation	
Mark McKinnon	Western Power	From 9:45 AM
Wendy Ng	Shell Energy	
Patrick Peake	Perth Energy	
Jacinda Papps	Alinta Energy	
Toby Price	AEMO	Subject matter expert
Matt Shahnazari	Economic Regulation Authority	
Noel Schubert	Small-Use Consumer representative	Observer
Dev Tayal	Tesla Energy	
Rebecca White	Collgar Wind Farm	
Andrew Stevens	Clear Energy	
Richard Bowmaker	Robinson Bowmaker Paul (**RBP**)	
Ajith Sreenivasan	RBP	
Tim Robinson	RBP	
Stephen Eliot	Energy Policy WA (**EPWA**)	
Shelley Worthington	EPWA	

Apologies	From	Comment
Dora Guzeleva	Chair	
Dale Waterson	Merredin Energy	
Andrew Walker	South32 (Worsley Alumina)	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30am.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	
3	**Minutes of RCMRWG meeting 2022_03_17** Draft minutes of the RCMRWG meeting held on 17 March 2022 were distributed in the meeting papers on 29 April 2022. The RCMRWG noted the tracked changes in the draft minutes and accepted the minutes as a true and accurate record of the meeting. **Action: RCMRWG Secretariat to publish the minutes of the 17 March 2021 RCMRWG meeting on the RCMRWG web page as final.**	**RCMRWG Secretariat**
4	**Action Items** The paper was taken as read. All action items were closed.	
	The slides for agenda items 5 to 10 are available on the webpage for the RCM Review (https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group).	
5	**Project Timeline** Mr Robinson presented the timeline in slides 4 to 6 and noted the following about the status of the project: • considerable progress has been made on the project – the international literature review is complete, data has been gathered, and the system stress modelling has commenced (initial results are discussed under agenda item 6); • indicative directions have been identified for defining the capacity service and the planning criterion based on the system stress modelling; • further modelling and analysis are to be completed; and • a draft consultation paper is to be completed in August 2022.	

Item	Subject	Action

6	**System Stress Modelling Outputs**
	Mr Bowmaker presented the initial results of the system stress modelling in slides 7 to 17. The discussion was as follows:
	• Mr Bowmaker noted that
	  ○ the system stress modelling looked at:
	    ▪ the causes of system stress in 2022, 2030 and 2050;
	    ▪ how the current generation mix and other capacity sources will operate and how they will support the identified types of current and future system stress;
	    ▪ whether the current Planning Criterion is adequate to meet the capacity requirements in the South West Interconnected System (**SWIS**);
	  ○ the modelling methodology was to:
	    ▪ generate future load and variable renewable energy traces;
	    ▪ insert the traces into a system adequacy model;
	    ▪ determine whether the system has sufficient capacity to meet demand on an hour by hour basis, at the points of system stress; and
	  ○ this quantifies how often system stress events occur, the extent to which system stress occurs, what times of the day stress occurs, etc., which allows conclusions to be drawn on whether the current Planning Criterion is adequate and the types of products that will be needed in the future.
	• Mr Bowmaker reviewed the scenarios that had previously been agreed by the RCMRWG for 2022, 2030 and 2050.
	  ○ Mrs Bedola asked whether additional wind and solar capacity is assumed to generate the hydrogen for scenario 3 and whether higher load was assumed for the creation of the hydrogen. Mr Bowmaker indicated that no specific technology assumptions were made – specific wind or solar capacity to generate hydrogen was not part of the results, nor was load for hydrogen generation.
	  ○ In response to questions from Mr Price, Mr Bowmaker indicated that:
	    ▪ behind the meter generation goes into the operational load forecast; and
	    ▪ no assumptions have been made around virtual power plants and how they are used.
	• Mr Bowmaker presented the initial modelling results (slide 10) and the key findings in terms of capacity additions (slide 11).
	• Mr Bowmaker presented the key finding in terms of minimum demand (slide 12).	

Item	Subject	Action
	○ In response to a question from Mrs Bedola, Mr Bowmaker indicated that the negative load results indicate load before accounting for demand flexibility and storage. ○ Mr Schubert noted that the SWIS has had peak demand greater than 4,000 MW in several years and asked why this does not seem to occur in the results. Mr Bowmaker indicated that high peaks do not appear because the results are an average load profile, and the final modelling will use a Monte Carlo simulaion approach with a number of different demand shapes to address extreme peak demand. Mr Schubert pointed out that these peak events would show what capacity is required. ○ In response to a question from Mr Higgins, Mr Bowmaker acknowledged that the system stress modelling only considers what generation capacity is required and that economic modelling will be done in the next stage. ○ In response to a question from Mr McKinnon, Mr Bowmaker indicated that negative operational load indicates periods where the market operator will need to find ways to absorb the additional energy in terms of bringing in batteries or demand side management. • Mr Bowmaker presented the key finding in terms of demand shape, (slide 13). ○ Mr Schubert suggested that the demand profile will be flatter if retail tariffs are structured properly, and incentives are put in place for electric vehicles (**EV**s). Mr Bowmaker indicated that the modelling accounted for EV charging, which tends to be in the evening – this pushes the peak later in the day and leads to a broader peak, but the duck curve shape does not disappear. • Mr Bowmaker presented the key finding in terms of timing of firming resources (slide 14). ○ Ms White pointed out that the modelling shows that unserved energy still occurs in the traditional peak periods, which is usually due to insufficient capacity, and indicated that she had expected that unserved energy in the future would be caused by low load and instability leading to system black or partial system black events. Ms White asked whether the modelling indicates that there are no low load issues that would lead to unserved energy? ▪ Mr Bowmaker indicated that the model identifies unserved energy that is caused by a shortage of capacity, not things happening as a result of system stability issues. ▪ Ms White asked whether this definition is appropriate going forward and raised the question of whether flexibility should be considered in the RCM.	

Item	Subject	Action
	▪ Mr Robinson indicated that issues associated with low load are addressed later in the agenda and suggested to return to the issue at that time. ○ Mr Bowmaker pointed out that the broader peak that is expected by 2050 suggests that unserved energy could occur as late as 10:00pm, so the hours over which capacity services are defined may need to be extended. Mr Robinson suggested that, alternatively, it may need to be ensured that the capacity is available in all of the peak hours. ○ Mrs Papps asked how this relates to 14-hour fuel requirement for Scheduled Generators and whether fuel requirements are only needed in the five hours in the back half of the day. Mr Robinson acknowledged that it could be argued that the critical period is shorter than 14 hours. The Chair suggested that fuel requirements will be considered when assessing the methods to assign Certified Reserve Capacity. Mr Robinson suggested that fuel requirements should be discussed later when discussing ramping and flexibility. ○ Mr Price asked whether the fleet assumptions will drive the types of unserved energy experienced – for example because reliance on storage pushes unserved energy to later in the day. Mr Price indicated that he had envisaged that a base case for the characteristic of demand would be developed and used to assess what types of fleet capabilities achieve certain levels of unserved energy. Mr Robinson clarified that this was why different scenarios were modelled. • Mr Bowmaker presented the key finding in terms of timing of demand ramping (slide 15). ○ Mr Bowmaker indicated that: ▪ the modelling showed that much higher demand ramping rates are required as the demand shape changes in the later years – about 2,000 MW/h by 2050 (about three times the current rate); and ▪ the ramping is well within the capabilities of current technologies like open cycle gas turbines (**OCGT**s) and batteries, but options to address ramping will be more limited with the zero carbon emissions policy, which will rule out OCGTs. ○ In response to questions from Mrs Bedola and Mr Stephens, Mr Bowmaker clarified that the model does not assess intra-interval ramping because this is a function of the ESS market and not the capacity mechanism. ○ Mrs Bedola asked whether the ramping issues are driven by renewables or load? Mr Bowmaker indicated that it is a	

Item	Subject	Action
	combination of what is going on behind the meter and the volatility of wind and solar. • Mr Bowmaker presented the key finding on the methods of measuring unserved energy (slide 17). ○ Mr Bowmaker pointed out the different ways to measure unserved energy: ▪ unserved energy as a percentage of total load (**EUE%**); ▪ loss of load hours (**LOLH**); and ▪ loss of load events (**LOLEv**). ○ Mr Bowmaker pointed out that the different scenarios resulted in different types of unserved energy in terms of EUE%, LOLH and LOLEv, which will be important when it comes to discussions on the Planning Criterion. ○ Mr Tayal asked whether the modelling showed any events with a continuous number of hours of unserved energy that would match the expected MWh profile of batteries or other storage technology that is required in 2030 or 2050? Mr Bowmaker indicated that RBP can present this information. ○ Mr Price asked if the modelling accounts for extreme scenarios, such as multiple days with a lack of wind or low irradiance. Mr Bowmaker clarified that the initial results presented are based on hour-by-hour modeling of averaged demand but that the final results will be based on a Monte Carlo simulation approach, modelling all actual traces available and considering many different scenarios, including extreme weather events. Mr Higgins asked if the modelling had assessed whether sufficient Scheduled Generation will be available in 2030. Mr Robinson clarified that this was the case, based on the current plan for generator retirements.	
	ACTION: RBP is to provide information to the RCMRWG on how the number of continuous LOLH matches against battery profiles.	**RBP**
7	**Capacity Services** Mr Bowmaker and Mr Robinson presented the initial assessment of the capacity services needed in the SWIS in slides 19 to 23. The discussion was as follows: • Mr Bowmaker presented the initial key findings of the assessment of the characteristics of the capacity needed in the SWIS (slide 19). ○ Mr Bowmaker confirmed that, at this point, the model has not identified any ramp rates that cannot be addressed by the available essential system services (**ESS**). ○ Ms White questioned how capacity characteristics beyond a simple MW requirement can be incentivised, considering that the Reserve Capacity Price is out of scope for the review. Ms	

Item	Subject	Action
	White considered that, without changing the Reserve Capacity Price it will be difficult to incentivise different capacity products, such as capacity from different technology types and in different locations. Ms White emphasised that incentives for having capacity in different locations on the network is important to increase the resilience of the system. Mr Robinson clarified that the capacity needed in future will not be solely defined by peak demand but also by other characteristics, such as ramping capabilities. Mr Robinson noted that the option to address the ramping needs through the RCM are discussed later in the presentation. Mr Robinson noted that there are different ways to address the needed characteristics that are in scope of the RCM Review, such as different capacity classes or methods for assigning Certified Reserve Capacity (**CRC**). Mr Robinson noted that the results indicate that there will be a need in the future for capacity to be more flexible and available over a wider range of hours than currently needed. Currently, different requirements for availability apply to different technology types with Scheduled Generators being the only facilities that must be able to respond at any time. In the future, it will be important that all facilities can respond in a wide range of hours. Mr Price considered that it may be beneficial if the RCM takes system resilience into account by setting appropriate minimum standards in the allocation of CRCs. ○ Ms White noted that Electrical Storage Resources only have to be available for four hours. ○ Mr Robinson noted that the objective is to find a technology neutral approach by defining the system need and the product to address it. Mr Robinson noted that the RCM Review is aiming to identify a common approach for certifying different technologies. Mrs Papps supported simplifying/rationalising the methods for assigning CRC and noted that the current regime is extremely complex, which has the potential to discourage investment. • Mr Robinson presented the initial assessment on whether flexibility should be addressed through the RCM (slide 20). ○ Mr Robinson noted that the initial results show that, by 2050, the demand ramp rates exceed 2 GW / hour and that the resulting need for load shaping will dominate the need for firming capacity. Mr Robinson noted that this need for fast ramping capacity can be addressed in different ways: ▪ as a specific capacity product with a specified target;	

Item	Subject	Action
	▪ as a specific class for capacity that is more capable and therefore gets capacity allocated before the other classes; and/or ▪ address flexibility through the ESS market rather than the RCM. Mr Robinson noted that demand side management could help addressing the issue, but in order to do so, the regime for DSPs will need to be changed. ○ Mr Shahnazari considered that, if ramping capability is considered as a separate product or 'class', its pricing and demand curve might be separate to the system adequacy product and based on its supply cost and benefit to the system. Therefore, this becomes a separate service itself. Mr Shahnazari considered that combining the services without separation of prices should be considered with caution. If not designed carefully, it is likely to distort price signals for system adequacy and ramping flexibility services. If, in the future, the system requires a system adequacy product but not ramping flexibility, or vice versa, a single price for both services may distort the signal for each service to enter the market. ○ Mr Peake suggested that system adequacy and fast ramping should be sought separately. However, if ramping is driving the capacity need then both system adequacy and ramping should be sought in a combined process so that the overall cost can be optimised. ○ Mrs Bedola considered that the market as a whole needs to encourage the right generation mix., Therefore, the RCM and the energy and ESS market together must provide the revenue that encourages investment in the services needed. ○ Mr Shahnazari noted that the rules already allow procurement of fast ramping services through the ESS market. Mr Robinson agreed that fast ramping can be included as a distinct service in the ESS market and noted that the question is whether inclusion in the ESS market is sufficient to ensure the required investment in fast ramping capacity. ○ Mr Robinson confirmed that the rules allow for a fast-ramping service to be procured through the Supplementary Essential System Service Mechanism (**SESSM**) if a need for this service is identified for the short term. ○ Ms White cautioned against the building of additional administrative mechanisms to avoid impeding competition. Ms White considered that the market should be designed to incentivise the needed services and administrative mechanisms such as the SESSM should only be a backstop solution.	

Item	Subject	Action
	Mrs Papps, Mrs Bedola, Ms Ng, and Mr Peake supported Ms White's comment. ○ Mr Shahnazari suggested that fast ramping capacity could be procured through its own mechanism, similar to the RCM, instead of including the procurement in the RCM. ○ Mrs Bedola noted that the setting of the Electric Storage Resource Obligation Intervals limits how to operate batteries in the time before those intervals. ○ Mr Price noted that AEMO is developing options to incorporate ramping (Operating Reserve) in the NEM and suggested to consider how this is proposed to be designed and integrated into any capacity mechanism that is introduced in the NEM. Mrs Papps noted that the Australian Energy Market Commission's (**AEMC**) rule change about ramp rates in the NEM has been deferred until June 2023 to wait for the outcome of Energy Security Board's (**ESB**) work on the capacity mechanism. ○ Mr Robinson clarified that the modelling suggests that the fast-ramping needs in the WEM can be addressed by existing technology but the question is how to encourage a sufficient amount of the required capabilities. Mr Robinson noted that the next steps of the RCM Review will include a more detailed assessment of whether the existing market mechanisms encourage sufficient fast-ramping capacity or if additional incentives are needed. ○ Mr Robinson indicated that, based on the RCMRWG's discussion, it will be worth investigating whether capacity classes can be used to address the need for fast-ramping capacity. Mr Higgins supported this approach. • Mr Robinson presented the initial assessment of whether the low load issue should be addressed through the RCM (slides 22 and 23). ○ Mr Robinson noted that, to address the low load through the RCM: ▪ a 'reverse capacity' product would be needed, assigning credits for the capability of increasing load or decreasing generation; and ▪ an additional planning criterion would be needed for such a service. Mr Robinson noted that the initial results indicate that such a service may be needed around 25% of the Trading Intervals by 2050 which is significantly more than the Trading Intervals where a capacity service is needed. ○ There was discussion about whether consumers should have the right to spill energy into the system at any time.	

Item	Subject	Action
	▪ Mr Stevens considered that allowing distributed energy resources (**DER**) to spill energy into the system at any time and potentially paying them for not spilling at times poses a risk to investors in larger scale generation. Mr Stevens considered that DER generation should have to register to obtain the right to spill into the system. Ms White supported Mr Stevens' comments. ▪ Mrs Bedola noted that restricting consumers from spilling energy into the system may result in consumers disconnecting from the network. ▪ The Chair noted that whether generation from DER should be restricted was considered by the DER Roadmap and is not in scope of the RCM Review. o Mr Huxtable considered that investment in large scale capability to increase load requires multiple years of lead time and significant capital expenditure. o Mr Peake considered that a lot of money is spent on enabling the absorption of DER and cautioned that increasing prices for consumers by too much could threaten the energy transformation and lead to support coal fired generation. o Mr Shahnazari considered that there should be a framework for deciding which services should be part of the RCM and which should not. For example, what makes us to consider ramping flexibility can be included in the RCM, but not other ESS services?	
8	**Planning Criterion** Mr Robinson presented the conclusions about the assessment of the Planning Criterion based on the initial results and the international review (slides 25 to 27). The discussion was as follows: • Mr Robinson noted that: o The international review suggests keeping the two-limbed Planning Criterion. o The system stress modelling indicates that EUE% should be retained as one of the limbs of the Planning Criterion. o The initial results indicate that there is no benefit in using both LOLH and LOLEv as system stress measurements for the Planning Criterion. o The initial results showing a small number of short and small outages indicate that it will be more appropriate to use peak load or LOLEv and not LOLH as the second limb of the Planning Criterion. o Further modelling should inform whether peak load or LOLEv are more appropriate measures for the second limb of the Planning Criterion.	

Item	Subject	Action
	• Ms White asked whether there is any policy direction for the reliability target. Mr Robinson clarified that the assessment of the Planning Criterion includes a cost-benefit analysis to assess the trade-off between higher reliability requirements and costs, noting the requirement that the current reliability standard should not be eroded. • Mr Schubert asked if the modelling differentiates between long- and short-duration storage. Mr Bowmaker clarified that the modelling assumes that the Electrical Storage Obligation Intervals would span four hours. Mr Bowmaker noted that the modelling to date was an hour-by-hour assessment and therefore not assessing when electrical storage resources (**ESR**) are charging over time, but that this will be assessed in the next round of modelling. • Mr Peake considered that the public would be most upset by deep outages and that regular but small outages can be spread around so no one customer is greatly affected. • Mrs Papps noted that Alinta Energy broadly supports the retention of a two-limbed Planning Criterion and asked how this will affect the fuel requirement for Scheduled Generators. Mrs Papps noted that the weakness of the current Planning Criterion is that it doesn't set an evidence-based period for how long capacity should be available. Mr Peake noted that the fuel requirement for Scheduled Generators will become a big issue if there is an increase in reliance on DSPs and the question is what availability DSPs will have to provide. The Chair noted that the fuel requirement will be considered when assessing the methods for assigning CRC. • Mr Robinson noted that even if the Planning Criterion is to be retained, the following aspects need to be addressed: o the reserve margin will need to be assessed to account for the largest contingency, which also sets the need for Spinning Reserve, and the largest contingency is now a network outage combined with the loss of generation from DER, not failure of the largest generator; and o whether CRC should be assigned based on the installed capacity (**ICAP**) or the unforced capacity (**UCAP**). • Mr Shahnazari referred the RCMRWG to the ERA's discussions in relation to the reserve margin in the following two publications: o Rule Change Proposal for the review of the Relevant Level Methodology, page 42;[1] and	

[1] The Rule Change Proposal is published on the Coordinator's website: Rule Change RC_2019_03 (www.wa.gov.au)

Item	Subject	Action
	○ 2020 Review of two market rules intended to incentivise the availability of generators, p. 16-17,65.[2] • Mr Shahnazari noted that keeping a two-limbed Planning Criterion has implications on the capacity value because Facilities may contribute differently to the two limbs. • Mr Higgins asked whether schedulable and non-schedulable generation should be separated into different availability classes. Mr Robinson noted that this will be considered when assessing the methods for assigning CRC.	
9	**Support for Preliminary Directions** The RCMRWG supported the preliminary directions.	
10	**Next Steps** Mr Robinson noted that the next step is modelling the alternative planning criteria and assessing the effect on the capacity target and system reliability. The next RCMRWG meeting in June 2022 to discuss: • final results for the assessment of capacity services and the Planning Criterion; and • CRC allocation approaches. The Chair invited RCMRWG members to provide out of session comments on the system stress modelling and the preliminary directions for the planning criterion by 13 May 2022. Ms White suggested that any out of session comments on the presented material should be consolidated and included in the papers for the next RCMRWG meeting. The Chair noted that how out of session feedback will be reported back to the RCMRWG will depend on the nature of the feedback.	
	ACTION: RCMRWG members are to provide any further feedback and comments on the system stress modelling and the preliminary directions on the planning criterion to the RCMRWG secretariate.	**RCMRWG members (13/05/2022)**
11	**General Business** No general business was discussed.	

The meeting closed at 11:30am.

2 The report is published on the ERA's website: [2020 Review of Incentives to Improve Availability of Generators - Economic Regulation Authority Western Australia (erawa.com.au)]

Government of **Western Australia**
Energy Policy WA

Minutes

Meeting Title:	Reserve Capacity Mechanism Review Working Group (**RCMRWG**)
Date:	2 June 2022
Time:	9:30am – 11:30am
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	
Paul Arias	Bluewaters Power	
Rhiannon Bedola	Synergy	
Oscar Carlberg	Alinta Energy	Subject matter expert
Zhang Fan	Collgar Wind Farm	Proxy for Rebecca White
Manus Higgins	AEMO	
Brad Huppatz	Synergy	Subject matter expert
Mark McKinnon	Western Power	
Wendy Ng	Shell Energy	
Jacinda Papps	Alinta Energy	
Toby Price	AEMO	Subject matter expert
Matt Shahnazari	Economic Regulation Authority	
Noel Schubert	Small-Use Consumer representative	
Andrew Stevens	Clear Energy	
Andrew Walker	South32 (Worsley Alumina)	
Nimish Trivedi	Synergy	Subject matter expert
Richard Bowmaker	Robinson Bowmaker Paul (**RBP**)	
Ajith Sreenivasan	RBP	
Tim Robinson	RBP	
Stephen Eliot	Energy Policy WA (**EPWA**)	
Laura Koziol	EPWA	
Shelley Worthington	EPWA	

Apologies	From	Comment
Peter Huxtable	Water Corporation	
Patrick Peake	Perth Energy	
Dev Tayal	Tesla Energy	
Dale Waterson	Merredin Energy	

Item	Subject	Action

1 Welcome

The Chair opened the meeting at 9:30am.

2 Meeting Apologies/Attendance

The Chair noted the attendance as listed above.

3 Minutes of RCMRWG meeting 2022_03_17

Draft minutes of the RCMRWG meeting held on 5 May 2022 were distributed in the meeting papers on 27 May 2022.

The RCMRWG noted the tracked changes in the draft minutes.

Ms Koziol noted the following additional changes to the minutes that had been requested after the circulation of the papers:

- Page 5:
  - In response to questions from Mrs Bedola and Mr Stephens, Mr Bowmaker clarified that the model does not assess intra-interval ramping because this is a function of the ESS market and not the capacity mechanism.
- Page 11:
  - Mrs Papps noted that Alinta Energy broadly supports the retention of a two-limbed Planning Criterion and asked how this will affect the fuel requirement for Scheduled Generators. Mrs Papps noted that the weakness of the current Planning Criterion is that it doesn't set an evidence-based period for how long capacity should be available.

The RCMRWG accepted the minutes, as amended, as a true and accurate record of the meeting.

Action: RCMRWG Secretariat to publish the minutes of the 5 May 2022 RCMRWG meeting on the RCMRWG web page as final. — **RCMRWG Secretariat**

4 Action Items

The paper was taken as read.

Item	Subject	Action
	The slides for agenda items 5 to 9 are available on the webpage for the RCM Review (https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group).	
5	**Project Timeline** Mr Robinson presented the timeline.	
6	**Certified Reserve Capacity (CRC): Contribution to Resource Adequacy** Mr Robinson presented the options for assessing resource adequacy (slides 10 to 21). The following issues were discussed: • Regarding slide 11, Mr Price clarified that Non-Scheduled Facilities containing only Electric Storage Resources (**ESR**) will be assigned Certified Reserve Capacity (**CRC**) based on linear derating for the first five years, after which they will be assessed under the relevant Level Methodology (**RLM**). • Mr Robinson explained the concepts of Effective Load Carrying Capacity (**ELCC**), Marginal Reliability Index (**MRI**) and Equivalent Firm Capacity (**EFC**). • Mr Robinson noted that these methods to measure the contribution to reliability are very similar and that stakeholders have previously reviewed the ELCC method. • Regarding the MRI, Mr Shahnazari considered that there is no order of entry in terms of contribution to the reliability of the system, so the MRI risks undercompensating facilities for their contribution. Mr Robinson noted that the MRI does not calculate the contribution to reliability as a MW value, but as a ratio of the increased reliability with an incremental increase in capacity from the assessed facility and the increased reliability with an incremental increase in perfect capacity. Mr Shahnazari noted that he is concerned that a Facility's MRI may be very low when there is over-capacity. • Mr Robinson noted that, when compared with the ELCC, the disadvantage of the MRI is that it is more difficult to explain and less transparent, and the advantage is that less iterations are needed to determine a Facility's MRI. • In response to a question form Mrs Bedola, Mr Robinson clarified that EFC can be determined on a facility or a fleet basis. Mrs Bedola asked whether the EFC method is applied on a fleet basis in any other jurisdiction and Mr Robinson noted that he is not aware of any such cases. • Mr Robinson presented the proposed options for assessing the contribution to reliability on slide 19. The following points were raised:	

Item	Subject	Action
	○ Mrs Papps asked how the proposed approaches to determine contribution to reliability link back to the system stress analysis. Mr Robinson clarified that the system stress modelling links to the assessment of whether to include a flexibility product in the Reserve Capacity Mechanism (**RCM**). Mr Robinson noted that the ELCC accounts for any peak stress event in any reference period. ○ Mr Shahnazari considered that the proposed options 1 and 2 need to be considered as mutually exclusive because ELCC can be a benchmark for all facilities but that the ELCC for some facilities such as non-intermittent facilities and ESR does not require a probabilistic determination. ○ Mr Carlberg noted his concern that under a probabilistic method it will not be clear for investors and system planners at which times availability is valued. Mr Carlberg suggested to explore a method that approximates a broader range of system stress intervals instead of an ELCC based on the system stress periods identified during the system stress modeling. Mr Carlberg considered that the key disadvantage of the current RLM is that it focusses on the highest load for scheduled generation and thus fails to recognize the contribution of intermittent generators to reduce the peak. Mr Robinson confirmed that one issue identified with ELCC (as shown on slide 21) is that it selects a small sample of historical system stress events, so a new system stress event may have a potentially large effect on the outcome from year-to-year. Mr Robinson noted that this issue will be assessed further. Mr Robinson suggested to explore alternative methods for assigning CRC to intermittent generators, that are not probabilistic. ○ Mr Carlberg noted his concern that applying a marginal ELCC could duplicate the signal already provided by the demand curve setting the Reserve Capacity Price. ○ Mr Schubert considered that wind can be reasonable on the south coast but light in the north during very hot weather. Mr Schubert asked whether this matters for assessing the wind fleet and individual wind farms? ○ Mr Robinson clarified that the ELCC method would assess the performance of individual wind farms during system stress and their ELCC would reflect this. ○ Mrs Papps raised concerns that the ELCC is volatile and not transparent and does not meet the guiding principles of the RCM Review.	

Item	Subject	Action
	Mr Robinson noted that the ELCC is used in other jurisdictions, while the current RLM is not, and that, internationally, investors have been able to manage the issues raised by Alinta. The Chair acknowledged that certainty for investors and simplicity is important but noted that the most important objective of the RCM Review is to develop an RCM that ensures adequate system reliability. The Chair emphasised that, to achieve this objective, the RCM must recognise the actual contribution of various types of facilities to system adequacy and security. ○ Mr Carlberg considered that a disadvantage of the ELCC is the uncertainty for investors because a Facility's ELCC can be affected by the entrance or withdrawals of other facilities. ○ Mr Robinson noted that the ELCC would be recalculated every year. ○ Mrs Bedola considered that it is also important to consider the interaction between ELCC and Network Access quantities (NAQ). Mrs Bedola noted that, even where the ELCC was reduced for only one year, this could have a long-lasting impact on a facility's NAQ. ○ Mr Stevens considered that monthly weather variations will become increasingly relevant in the future and will result in different risks for each month and season. Mr Stevens considered that applying the RCM on an annual basis will oversimplify the problem and forego the benefits of a monthly approach. ○ Mr Robinson suggested that monthly modeling results can be assessed to inform further investigations of this issue.	
7	**CRC: Outages** Mr Robinson presented the options for accounting for outages in the RCM (slides 22 to 25). The following issues were discussed: • In response to a question form Mr Price, Mr Robinson clarified that, in general under the unforced capacity (**UCAP**) approach, it is not considered whether outages coincide with system stress events. Mr Robinson noted that it is possible to consider the timing of outages under the UCAP approach but that this would increase complexity. • Mr Shahnazari noted that the ERA had reviewed the UCAP regime including the use of equivalent demand forced outage rate(**EFORd**)[1] in its review of the methodology for incentivising availability of generators.	

[1] In the PJM EFORd is defined as a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate

Item	Subject	Action
	• In response to a question from Mrs Papps, Mr Robinson noted that the ELCC of a Facility represents its capacity value under the UCAP approach. Therefore, intermittent generators would not get penalised twice for poor performance during system stress if both the ELCC method and the UCAP approach are applied. • Mr Huppatz asked whether the installed capacity considered under the ICAP approach is a facility's capacity at 41°C or if the approach would consider that certain facilities can generate more at lower temperatures considering that the SWIS is moving to a winter peaking system at times. Mr Robinson clarified that the adjustment to ambient conditions referred to the weather conditions expected at the time the capacity is needed and that this would be static. Mr McKinnon indicated that he considered that applying 41°C for RCM purposes across the SWIS does not reflect that: ○ the peak is shifting to times of the day with lower temperatures; and ○ temperature during the peak day could be very different for the south (e.g. Albany) and the metro area. • Mrs Papps considered that the WEM already provides several mechanisms to incentivise availability of capacity and that these mechanisms should be reassessed if the UCAP approach is implemented. The Chair noted that, under stage 2 of the RCM Review, the treatment of outages and the capacity refund regime will be assessed against the outcomes of stage 1 of the RCM Review. • Mr Carlberg asked what objective introducing the UCAP approach fulfills given that the current regime already penalises forced outages and incentivises participants to avoid forced outages. Mr Robinson noted that the objective of the UCAP approach is to increase certainty that sufficient capacity is procured. Mr Carlberg considered that outages cannot be forecast with sufficient accuracy to achieve this objective. The Chair noted that historically forced outages have occurred during system stress and that the objective is to provide certainty that system demand can be met adequately. • Mrs Papps asked whether the UCAP approach would be reflected in the Benchmark Reserve Capacity Price (**BRCP**) considering that: ○ no facility would get to 100% availability; and ○ more work to prevent forced outages may be undertaken with unintended consequences. Mr Robinson confirmed that the UCAP approach would need to be reflected in the BRCP, and that assessing the BRCP is part of the scope of works for the RCM Review.	

Item	Subject	Action
	• Mr Shahnazari noted that, in its review of the methodology for incentivising availability of generators, the ERA identified that the WEM Rules allow AEMO to discount the allocation of Capacity Credits to a generator for outages but that there is no clear guidance how to use this discretion.	
8	**CC: Preference for Resource Flexibility** Mr Robinson presented the options for addressing the need for flexibility in the RCM (slides 27 to 32). The following issues were discussed: • Mr Schubert considered that start-up time, speed of ramping and restart time should be considered as part of the flexibility. Mr Robinson agreed that RCM should address these aspects of flexibility. • Mr Shahnazari asked why ramping capabilities should be addressed through the RCM but not other Essential System Services (**ESS**). Mr Robinson clarified that the product would be a flexibility product, not a pure ramping product, but that the requirement would be set by the need for ramping capability, as the system stress modelling identified a particular need for ramping capabilities and it is expected that facilities that are capable of ramping will also be able to provide other ESS. • In response to a question form Mr Price, Mr Robinson clarified that the requirement for the flexibility product would be set by the relevant system stress events that may not necessarily coincide with system peak demand. • Mrs Bedola asked whether the flexibility product could be used as an RCM just for ESS requirements. Mr Robinson confirmed that a separate product could be defined for each ESS but noted that, based on the system stress modeling, the ramping capability was the only capability identified that may need long term investment signals. • Mrs Bedola asked how the assessment of ESRs to provide the flexibility service would account for the ESR Obligation Intervals. Mr Robinson noted that the question applies to any facility providing peak capacity and flexibility and that he considered that, at the time of dispatch, the obligations for the flexibility product would overshadow the obligation for the peak capacity product. • Mr Price considered that the interaction between the flexibility product and the Supplementary ESS Mechanism (**SESSM**) should be considered. Mr Price noted that the objective of the SESSM is to identify shortfalls in ESS services and underwrite the entry of the needed services. The Chair agreed with Mr Price and noted that the SESSM will be reassessed to remove any overlaps. The Chair considered that the	

Item	Subject	Action
	current design of the SESSM could incentivise the withholding of ESS capacity until a SESSM is called, which could also lead to “double” recovery of costs in the RCM/SESSM. • Mr Price asked whether there is an intent to harmonise the certification of ESR with the requirement for fuel storage. Mr Robinson clarified that the intent is to assess this in the future, but that it was not intended to change the assessment of ESR now. The Chair noted that the certification of ESR will be reviewed but is not in the scope of the RCM Review as the recent decisions were aimed at providing investment certainty for this new technology. • Mr Huppatz considered that a low minimum generation level should not be part of the requirement for a flexibility product because it is more important that a facility can come on and off quickly. The Chair noted that turning on and off a facility with high minimum generation can lead to step changes in supply and how this contributes to the requirements for flexibility products will need to be assessed. • Mr Carlberg considered that capability classes are more complex then defining a minimum availability period and discounting facilities that are less available. Mr Robinson noted that the main distinction is between firm capacity and non-firm capacity based on probabilistic availability. However, all else being equal, capacity that is available for longer will be more valuable than capacity that is available for a shorter duration. The Chair noted that, in any case, the current availability classes needed to be reviewed because they do not appropriately account for hybrid facilities. In response to a question from Mr Shahnazari, the Chair clarified that the capability classes were proposed to address the peak capacity product and that the flexibility product would be addressed separately. Mr Schubert suggested to identify the need for different capability classes instead of prioritising capacity from one class over another. Mr Schubert considered that prioritising capacity that is available all the time may lead to over-procurement, to the detriment of capacity that provides other benefits, such as low emissions. The Chair noted that emissions are assumed to be addressed through Government policies and are not currently within the scope of the RCM Review. Mr Robinson acknowledged over-procurement of one class of capacity should be avoided if there is a more efficient way of procuring the needed capacity. • In response to a question from Mr Price, Mr Robinson noted that the CRC would be determined separately for the peak capacity and the flexibility product.	

Item	Subject	Action
	• Mrs Bedola asked whether discounting capacity for intermittent generators through the ELCC method and then giving them a lower priority based on the capability class will penalise intermittent generators twice for the limited availability. Mr Robinson clarified that the ELCC would be used to assign CRC and the capability classes would be used to prioritise procurement of capacity. • Mrs Papps asked whether a Facility with a lower capability class that is assigned Capacity Credits in one year could not be assigned Capacity Credits in a subsequent year. • The Chair clarified that, once a facility received Capacity Credits in one year it would be eligible, subject to its performance, in subsequent years to provide certainty to investors.	
9	**Next Steps** The RCMRWG agreed that, based on the discussion, the MAC should be advised that the following issues should be investigated further: • alternative methods for assigning CRC to intermittent generators, other than ELCC; • a more granular assessment of the capacity requirement, such as monthly or quarterly; • whether generation at 41°C is still adequate; and • whether minimum generation needs to be considered as part of the flexibility product.	
10	**General Business** No general business was discussed.	

The meeting closed at 11:30am.

Government of **Western Australia**
Energy Policy WA

Market Advisory Committee

Update from RCMRWG

28 June 2022

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

Agenda

Item	Item	Duration
1	Project Timeline	2 min
2	Session purpose	10 min
3	Planning criterion	5 min
4	Incentivising flexible capacity	15 min
5	CRC: Contribution to Resource Adequacy	5 min
6	CRC: Outages	5 min
8	Next Steps	3 min
Appendix	Comments from previous meetings	
Appendix	CRC allocation – further information	
Appendix	Updated System Stress Modelling Outputs	

1. Project Timeline

Project Timeline

10/06

Stage	Step	Short description	Analysis	21/01	28/01	4/02	11/02	18/02	25/02	4/03	11/03	18/03	25/03	1/04	8/04	15/04	22/04	29/04	6/05	13/05	20/05	27/05	3/06	10/06	17/06	24/06	1/07	8/07	15/07	22/07	29/07	5/08	12/08	19/08	26/08	2/09	9/09	16/09	23/09
1	Working group meetings		RCM Working Group meetings	WG				WG				WG							WG				WG		WG					WG									
1	MAC meetings		MAC meetings							MAC					MAC						MAC						MAC								MAC				
1	Step 1	Requirements analysis	(a)International Literature review																																				
1	Step 1		Gather assumptions and set up models																																				
1	Step 1		(b)Model system stress																																				
1	Step 1		(c)Analyse the required capacity services																																				
1	Step 2	Review Planning	(d)Assess the Planning Criterion																																				
1	Step 2	Criterion	(e)Assess the ICAP and UCAP Concepts																																				
1	Step 3	Review CRC allocation	(f)Assess CRC Allocation and identify options																																				
1	Step 5	Model CRC allocation	(h)Scenario Analysis - Model CRC allocation options																																				
1	Step 4	Review BRCP	(g)Analysis of the BRCP																																				
1	Consultation paper		Consultation paper																																				

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

2. Session Purpose

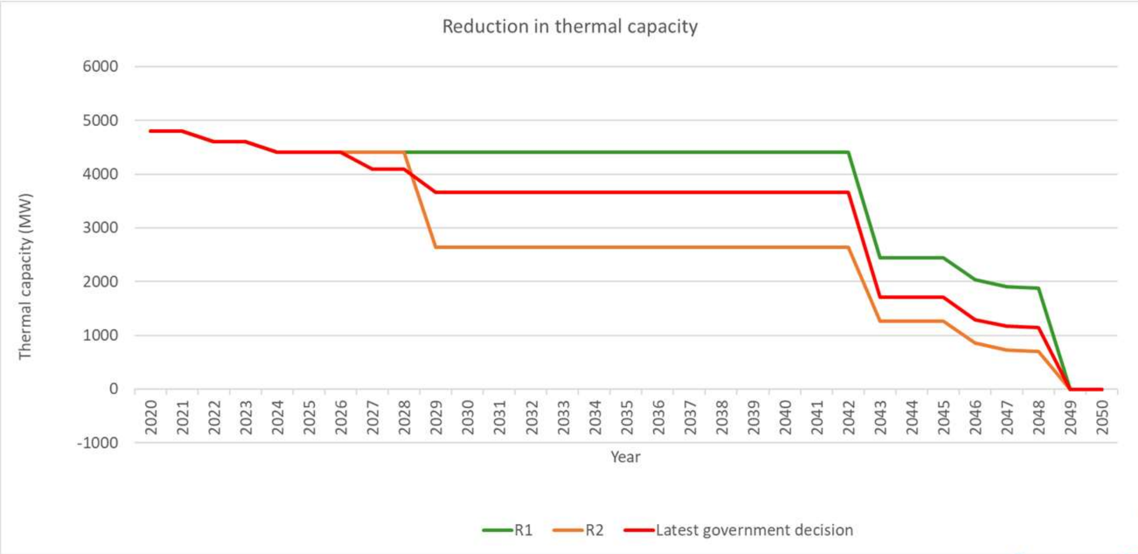
Purpose of this Session

- Having completed the system stress modelling, we use the results to inform proposals for evolution of the RCM.
- In this session we will discuss the rationale for, and high-level shape of, a potential new flexible capacity product, based on a target set according to a new limb of the planning criterion
- Finally, we will discuss proposed options to be assessed for CRC allocation.
- These options will be assessed in the next (final) stage of modelling, where we seek to quantify the effects of the various options on the economics of different technologies and evolution of the generation fleet
- We seek MAC's views on the proposed direction and options for final assessment as recommended by the working group.

Implications of the Recent Government Announcement

On 15 June, the WA government announced the retirement of all Synergy coal facilities by 2030, and no new gas fired facilities from 2030.

- This retirement programme falls between the assumptions made in our two 2030 scenarios, so no rework is needed for the system stress modelling.
- The announcement of significant investment in storage aligns with our assumptions about fleet evolution.
- We will incorporate the new retirement and build assumptions into the economic modelling. We will also consider changing assumptions based on the new ESOO.



What is the purpose of the RCM?

"***The purpose of the RCM is to ensure acceptable reliability of electricity supply at the most efficient cost***"

- Historically, 'acceptable reliability' could be achieved by procuring sufficient MW to avoid unserved energy at during peak demand throughout a hot day.
- In future, the peak demand will not last all day, and having sufficient MW to meet the peak may not be sufficient to maintain acceptable reliability (avoid unserved energy).
- Size (MW) is an important factor in the reliability contribution of a facility, but it is not the only factor. Also affecting facility contributions are:
  a. How firm the capacity is
  b. Whether it has any fuel restrictions
  c. Whether it has any availability restrictions (e.g. cannot be called at certain times).
  d. Whether it can start, stop, and change output quickly
  e. Whether it has a minimum generation level

Key Aspects of the RCM for Discussion Today

Four key topics to cover today:

1. Updates to the planning criterion (based on system stress modelling)
2. Recognising the contribution to other aspects of reliability (particularly flexibility)
3. Determining the contribution to resource adequacy for different facility capabilities
4. Accounting for outages in CRC and the planning criterion

3. The Planning Criterion

Planning Criterion for Peak Capacity Product

Issue: How should we set the reliability target for the SWIS?

Options considered:

- EUE only
- Peak/event based only
- Two limb: Event count and EUE
- Two limb: Peak load and EUE

Recommendation: retain the two current planning criterion limbs (Peak load and EUE)

Why:

- International scan shows that a single limb criterion risks missing some aspects of reliability
- EUE is the most nuanced measure
- Using a loss of load event count would be appropriate if analysis showed infrequent long and deep outages, but analysis shows that with the flattening of the peak, most loss of load events are short and shallow.

The RCMRWG agreed.

Does the MAC agree with the RCMRWG's recommendation to retain the two existing limbs of the Planning Criterion: peak load and EUE%?

NEM Reliability Review

The NEM Reliability Panel released its draft review of the NEM reliability criterion on 9 June 2022.

- The Reliability Panel determined that it would be economically efficient to reduce the EUE target from 0.002% to 0.0015%.
- The Reliability Panel considered a revised form of the reliability criterion, determining that:
  - the criterion needs to have more than one limb;
  - one of the limbs needs to be EUE, as this metric is more useful than the LOLP or LOLH used elsewhere; and
  - a ‘risk aversion’ limb could account for potential low probability deep/sustained outages that are possible in the NEM in coming years, but significant work will be required to finalise the design
- These proposals generally align well with the WEM direction but analysis of the WEM does not raise a concern over deep/sustained outages, so a novel ‘risk aversion’ approach is unnecessary.

The Reserve Margin in the Planning Criterion

Issue: The current Planning Criterion includes a reserve margin to account for outages coincident with peak load. As written, it no longer captures the largest contingency on the power system.

Options considered:

- Remove reserve margin altogether
- Retain the reserve margin as its is until completion of RCM review, then replace reference to largest generator with largest contingency
- Change the reference to largest contingency in advance of other RCM review changes

Recommendation: Make changes ASAP

Why:

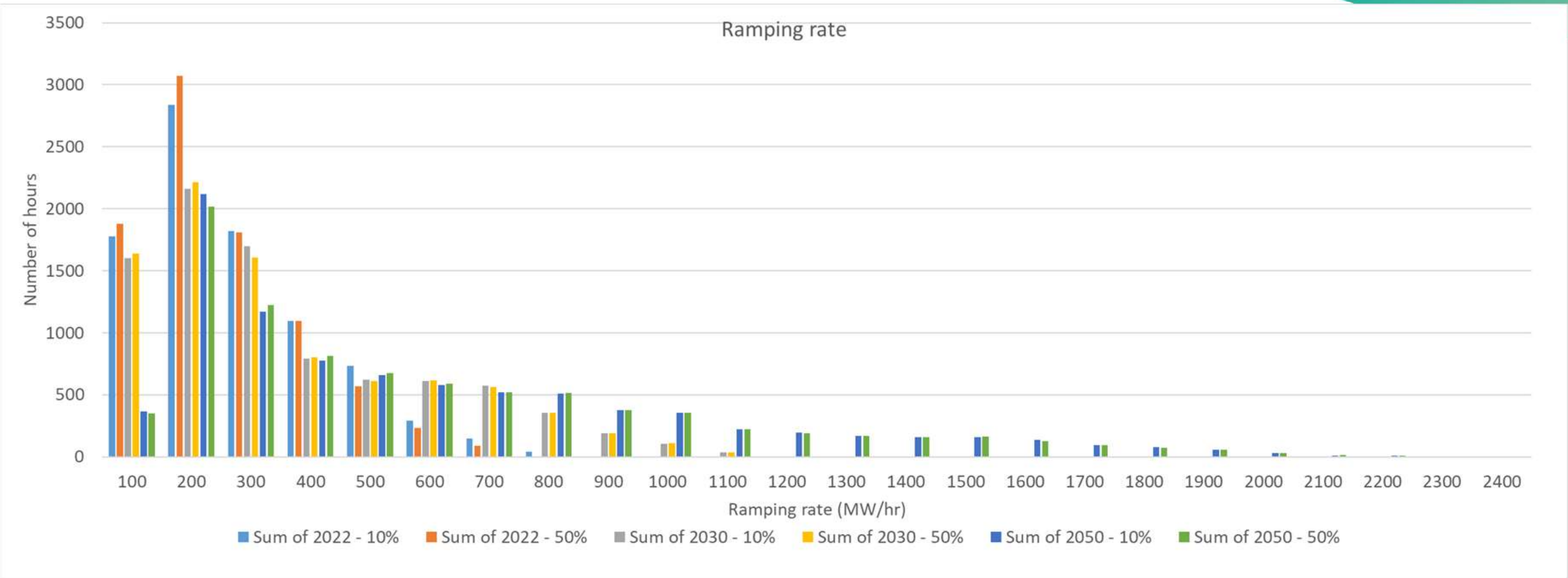
- Reserve margin is needed to allow ESS provision coincident with peak load
- Largest network contingency is already larger than largest generator
- Waiting would mean that next reserve capacity target would not cover all Spinning Reserve needed at peak

The RCMRWG agreed.

Does the MAC agree with the RCMRWG's recommendation that the reserve margin definition should be changed ahead of the rest of the RCM?

4. Incentivising Flexible Capacity

The Need for a Flexible Capacity Product (1)



- By 2050, we see much higher demand ramping than currently. The highest ramp rates in 2050 are >2000 MW/hr, 3x those in 2022.
- These ramp rates are still well within the capabilities of current technologies (e.g. OCGT), as long as sufficient capacity is available.
- However, under a zero-emissions policy, options for ramping capacity will be more limited, and it is not clear that this capability will be present in the fleet unless it is incentivised to be there.

The Need for a Flexible Capacity Product (2)

Issue: System stress modelling confirms that ramping needs will become more extreme. It is not clear that this need can be met by all of the capacity that provides the existing capacity service.

Options considered:

- Retain existing single capacity product based on two limbed planning criterion
- Specifically procure ‘flexible capacity’ through a second capacity product, with target defined by a new limb of the Planning Criterion, based on ramping needs
- Specifically procure capacity to meet each FCESS service, with additional planning criterion limbs for each FCESS

Recommendation: Explore financial viability of flexible capacity with single product or two products through economic modelling

Why:

- It is possible that flexible capacity will enter without a specific product, but economic analysis is needed
- Capacity that can contribute to meeting the ramping requirements would likely also be capable of providing other FCESS

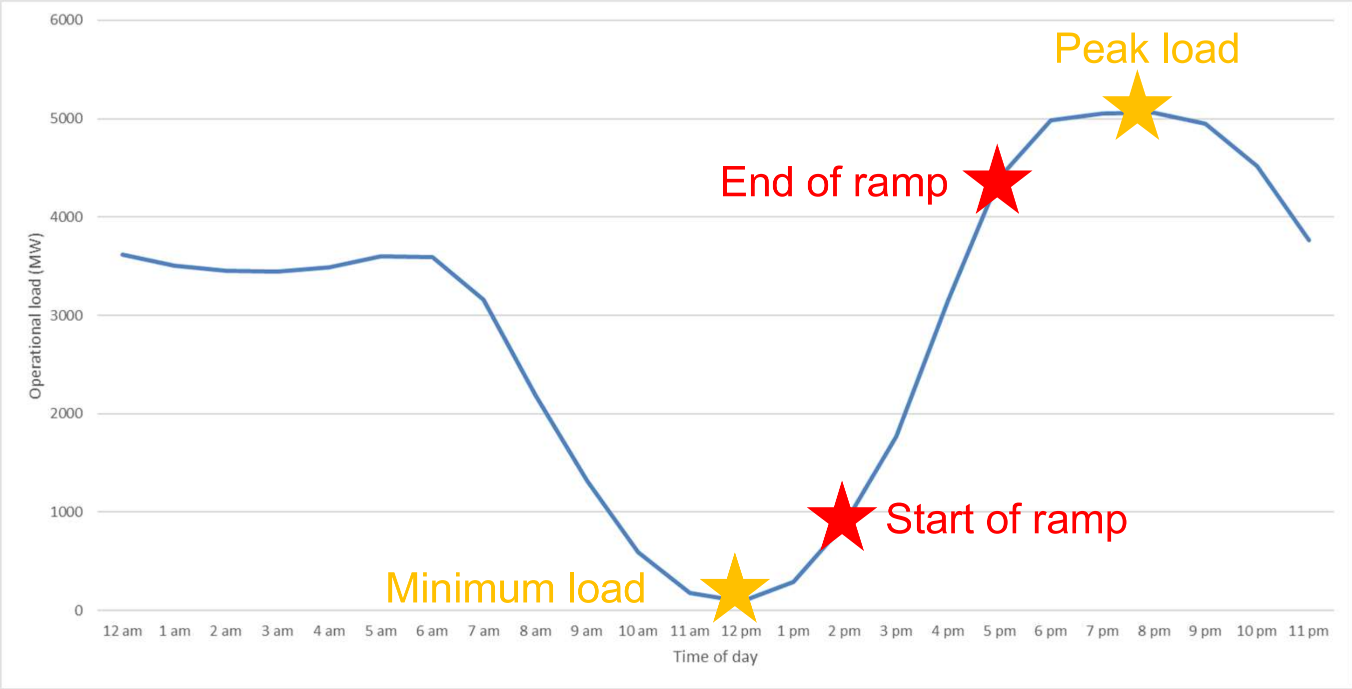
Does the MAC agree with the RCMRWG’s recommendation to compare a continuation of the current single-product RCM with a two-product RCM with separate targets for peak capacity and flexible capacity?

Defining a Flexible Capacity Target (1)

Issue: The rules need to provide a method to determine the target for flexible capacity.

Options identified:

- Difference between lowest and highest operational demand (simple but potentially over-procures); or
- Difference between start and end of ramp (more complex, but better matches the need).



Defining a Flexible Capacity Target (2)

Recommendation: Set flexible capacity target based on difference in operational load at the start and end of period with steepest ramp in the 10% POE load forecast, less the intermittent generation capacity curtailed at the start of the ramp.

Why:

- The key parameters driving the need for flexible capacity are the magnitude, slope, and duration of the ramp
- Using the 10% POE load forecast is consistent with the measure used for the peak capacity target
- Using the operational load means that only the uncontrollable ramp is accounted for
- Intermittent generation will be first to return to pre-curtailment levels
- Capacity Credits allocated to intermittent generators already account for their contribution to reliability at peak

The RCMRWG considered that the start and end of the period of the steepest ramp was the best reflection of the need for flexible capacity and did not comment on the specific approach to account for intermittent curtailment.

Does the MAC agree with the RCMRWG's recommendation to set a flexible capacity target based on the steepest ramp?

Does the MAC agree with the MAC Secretariat's proposed treatment of curtailed intermittent generation in the flexible capacity target?

Recognising Non-MW Dimensions of Capability

Availability Classes vs Capability Classes

Issue: In the current RCM, AEMO assigns Capacity Credits to facilities, up to the reserve capacity target, in order of availability class.

The current availability classes do not include a dimension for the ‘firmness’ of the capacity, even though intermittent and non-intermittent facilities have different CRC allocation methods and different capacity obligations.

MAC Secretariat conclusion: Retaining the current availability classes is not viable, as they do not allow for hybrid facilities

Proposal: Replace availability classes with “capability classes” that better align with firmness of delivery and availability obligations:

- Class 1: Unrestricted firm capacity (no fuel/availability limitations)
- Class 2: Restricted firm capacity (fuel/availability limitations)
- Class 3: Non-firm capacity

The RCMRWG agreed that the capability classes make sense but had reservations about the detail. The RCMRWG wanted to ensure that existing capacity would not miss out and noted that the design should avoid procuring more firm capacity than necessary if it would increase overall cost.

Does MAC agree with the MAC Secretariat’s proposal to replace the availability classes with new capability classes?

Proposed Changes to Capacity Obligations

See slide 77 for supporting analysis.

Issue: The current RCM requires scheduled facilities to be always available in the market. This was based on the historic assumption that capacity needed to be available during all hours of a hot summer day.

Options considered:

1. Retain current 24x7 availability requirement and fuel storage requirement
2. Require availability for morning and evening peak only, with hours set in the WEM Rules
3. Require availability for set hours only, with AEMO setting indicative obligation hours in ESOO based on likelihood of unserved energy (or for the flexibility product, likelihood of inability to meet ramp), with ability to amend hours at short notice

Recommendation: Option 3.

Why:

- Current requirement does not match timing of reliability risks
- Targeted availability hours will reduce fuel holding costs
- AEMO needs option to amend if circumstances change (similar to current approach to ESR obligation hours).

The RCMRWG agreed that changes to availability obligations made sense and considered that it would be important to clearly define any differences in obligation for flexible capacity providers (more detail in appendix).

Does the MAC agree with the RCMRWG's recommendation to have targeted availability obligations?

5. CRC: Contribution to Resource Adequacy

CRC allocation methods (1)

Issue 1: The current method for allocating CRC to intermittent generators was designed for an environment where intermittent generation made up a small proportion of the fleet. A key part of the review is to consider alternative CRC approaches.

Issue 2: The current method for assigning CRC to DSPs is controversial and was designed when DSPs were only expected to be dispatched at extreme peak load events and not other occasions of system stress.

Issue 3: The current RCM applies different methodologies for assigning CRC to different technologies – the RCM Review aims to reduce the complexity and ideally harmonise the approach for assigning CRC.

The working group considered:

- Different options for assigning CRC to different technologies based on probabilistic and non-probabilistic methods.
- Different probabilistic methods for assigning of CRC (preferred method: Effective Load Carrying Capability (ELCC)).

Working group feedback:

- Some RCMRWG members consider that the ELCC method best aligns with allocating capacity based on contribution at times of system stress.
- Other RCMRWG members are concerned that, for intermittent generators, a probabilistic method will be complex, opaque and have volatile outputs, and that an approach also including non-stress periods would provide better certainty for investors.

CRC Allocation Methods (2)

Recommendation: Assess the following three options, with the objective to determine CRC allocation that ensures ab acceptable reliability of electricity supply at the most efficient cost:

1. ELCC for intermittent generation and DSPs only, other facility types retain current methods
2. A single probabilistic method (ELCC) for all facility types
3. Simplified approach for intermittent generation and DSPs, other facility types retain the current methods

Why:

- International review shows that probabilistic methods are the norm for intermittent generation
- Of the probabilistic methods, ELCC and EFC are best aligned with planning criterion and steps can be taken to address volatility and long-term investment concerns
- WEM participants have exposure with ELCC through RC_2019_03
- Probabilistic methods can also be applied to non-intermittent generation
- Analysis can inform options for a simplified approach and its impact on overall system reliability

Does MAC agree with the RCMRWG's recommended options for assessing CRC allocation?

6. CRC: Treatment of Outages

Options to be assessed

Issue: How should we incorporate the effect of outages in the capacity certification process?

Options:

- ICAP = Installed capacity
- UCAP = Unforced capacity (ICAP less forced outage rate)

RCMRWG feedback:

- Some RCMRWG members consider that UCAP best aligns with the capacity service being delivered and automatically accounts for poor performance ex-ante rather than ex-post
- Other RCMRWG members expressed a preference to retain ICAP on the basis that current incentives are sufficient to ensure availability, historical outages are not good predictors of future outages, and that a UCAP approach may increase the overall cost of capacity procurement.

Recommendation: Assess impact of each approach for existing facilities on system reliability and on the overall cost of reserve capacity procurement.

Does MAC have any comments or questions on the ICAP vs UCAP assessment?

7. Next Steps

Next Steps

- CRC allocation analysis (incl. ICAP/UCAP and how many intervals are driving the ELCC)
- Calculate optimal EUE percentage (per slide 47)
- BRCP assessment for the two capacity products
- Economic impact modelling
- Working Group meeting mid July 2022
  - Discussion: BRCP approach
- Next MAC meeting 23 August 2022
  - Discussion: Consultation paper

- **Questions or feedback can be emailed to energymarkets@energy.wa.gov.au**

We're working for Western Australia.

Appendix: Comments from Previous RCMRWG Meetings

Relevant Comments from Previous RCMRWG Meetings to be considered in the Review – General

comment/feedback	Response
Need to be realistic about the duration of interruptions demand side providers will offer, especially if relying heavily on demand side reductions.	To be considered in design of demand response certification method.
Applying overly onerous penalties and creating missing money for intermittent generation needs to be avoided to meet the net-zero emissions target. Mr Carlberg suggested that one way to achieve this could be having different capacity buckets, potentially with different periods where they have guaranteed capacity payments.	Will be assessed through the design and modelling.
Reliance of generation from a single location can also be an issue e.g. in case of outages or network congestion.	Will be assessed through the design and modelling.
The certification requirement for Scheduled Generators to demonstrate sufficient fuel contracts and transport arrangements to maintain 14 hours of continuous operation imposes unnecessary high costs on Market Generators	Will be considered in design of CRC allocation.

Relevant Comments from Previous RCMRWG Meetings to be considered in the Review – ELCC

comment/feedback	Response/action
If using an ELCC approach to set CRC, a facility may have different contributions under each limb of the planning criterion.	To be considered in design of CRC allocations.
If there are only few system stress events the ELCC method may deliver very volatile outcomes and therefore may not send clear signals as to when intermittent generators should be available.	To be considered in further assessment of options for ELCC method.
The ELCC method is complex and difficult to explain to investors.	To be considered in further assessment of options for ELCC method.
About ELCC: Less complexity and less volatility would be an advantage.	To be considered in further assessment of options for ELCC method.
About ELCC: Correlation can be overstated and the impact be overestimated if only a few events of system stress are considered	To be considered in further assessment of options for ELCC method.

Note that the RCM Review is considering ELCC fresh and does not build on the ERA's RLM Review and the associated Rule Change Proposal. However, analysis from that review and rule change process will be considered.

Relevant Comments from Previous RCMRWG Meetings to be considered in the Review – ICAP vs UCAP

comment/feedback	Response/action
• Forced Outages should not be considered when allocating Certified Reserve Capacity (CRC) to generators and that this would increase risk to generators without improving reliability. • There are adequate incentives for generators to be available. • Forecasting outages is unlikely to be more accurate than applying a reserve margin. • Historic outages do not predict future performance and derating capacity for past outages will disadvantage generators that run more often because they have the greatest outage risk while also have the highest incentive to be available.	To be considered when modelling ICAP vs UCAP
concern about the risk to the reliability of the system from generators not delivering capacity when needed, including scheduled generators and renewable generators	To be considered when modelling ICAP vs UCAP To be considered in the design of CRC allocations.
It is important to review the purpose of the reserve margin and whether it is the best way to manage the effect of outages as it creates a free riding problem	To be considered when modelling ICAP vs UCAP.

Appendix: CRC Allocation – Further Information

Current WEM Arrangements (1)

Overview

Facility class	Component	Certification Method	Description
Scheduled and semi scheduled facility	Non-intermittent generating system	Capability at 41℃	Energy they can send out at 41℃.
Scheduled and semi scheduled facility	Intermittent generating system (IR)	Relevant Level Methodology (RLM)	Historical Intermittent Generating System output during Trading Intervals when surplus capacity (after intermittent generation) is the lowest, and therefore the system is under greatest stress.
Scheduled and semi scheduled facility	Electric Storage Resource (ESR)	Linear Derating Capacity	Ability to sustain output during The Electric Storage Resource Obligations Intervals during a Trading Day, given their storage (MWh) capability and capacity (MW).
Non-scheduled facility	Non-intermittent, IR, ESR	RLM	Historical output during Trading Intervals when surplus capacity (after intermittent generation) is the lowest, and therefore the system is under greatest stress.
Non-scheduled facility – only ESR	ESR	Linear Derating Capacity	Same as scheduled ESR facility.
Demand Side Participation		Relevant Demand	Based on the DSP's ability to curtail load relative to its Relevant Demand, which is indicative of the historical consumption of its Associated Loads during peak Trading Intervals.

Current WEM Arrangements (2)

Relevant Level Methodology

$$RLM\ (MW) = average\ output\ - \left(K + \frac{U}{average\ output}\right) \times variance\ of\ the\ output$$

- Output calculated during 5 historic years during periods where demand net of the sum of the output of all intermittent generators are the highest: **when output from scheduled generators is the highest. (**Load for Scheduled Generation or LSG)
- **The value of K depends on the probability distribution of demand and available capacity of existing resources and their correlation.** For instance, the outage rate of scheduled generators affects the value of parameter K. Outage rates determine the probability distribution of the available capacity of scheduled generators.
- **The value of parameter U** (added to address a lack of data about the performance of intermittent generators during extremely high demand periods) **is the ratio of**:
    - change in LSG, on days with peak LSG when air temperature was above 38 degrees Celsius to:
    - the mean output of the fleet of intermittent generators during peak LSG trading intervals

Note: The WEM Rules do not provide guidance on determination of K and U, but these are the definitions used by the ERA in its most recent review.

International Review

Overview

Market	Non-intermittent generation system	Intermittent system	ESR	DSP
Ireland	Derated based on historic outage	Class of resource derated based on historic outage	Derated based on historic outage	Based on historic performance
UK	All capacity facilities are derated to account for unplanned plant closure or maintenance **seasonally**	Based on **Equivalent Firm Capacity (EFC)**	Based on historic performance	Based on historic performance
ISO NE	Median of the existing generating capacity resource’s summer or winter seasonal claimed capability rating for the previous five years	Seasonal median output during reliability hours, currently investigating **Marginal Reliability Index MRI**	Historic performance	Reliability measured during historical peak demand or system stress periods
PJM	Nameplate capacity around the year subject to EFORd	**Effective Load Carrying Capability (ELCC)**	Nameplate capacity subject to EFORd from the availability of the component equipment	Resource’s estimated demand reduction value as submitted and reviewed

Effective Load Carrying Capacity (1)

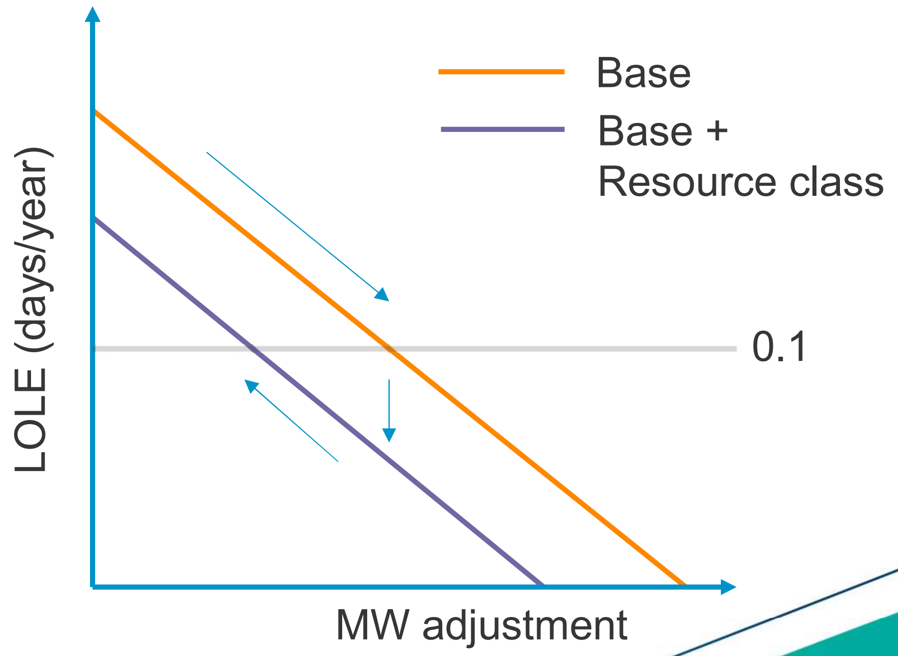
A resource's ELCC value measures the equivalent amount of additional load the system could serve ("carry") with the resource (versus without it), while meeting the same LOLE

- Determining LOLE in base case
- Adding resource to base case
- Adjusting load until LOLE is back to same level

$$ELCC = \frac{\boldsymbol{Load\ added\ (MW)}}{\boldsymbol{Resource\ nameplate\ added\ (MW)}}$$

Marginal ELCC: the incremental capacity value of a resource measured relative to an existing portfolio – individual resources or resources of same type are attributed an ELCC based on their marginal contribution to resource adequacy (e.g. wind class, solar class)

Portfolio ELCC: the combined capacity contribution of a combination of intermittent and energy-limited resources. This method inherently captures all interactive effects (e.g. wind + battery, solar + battery)



Effective Load Carrying Capacity (2)

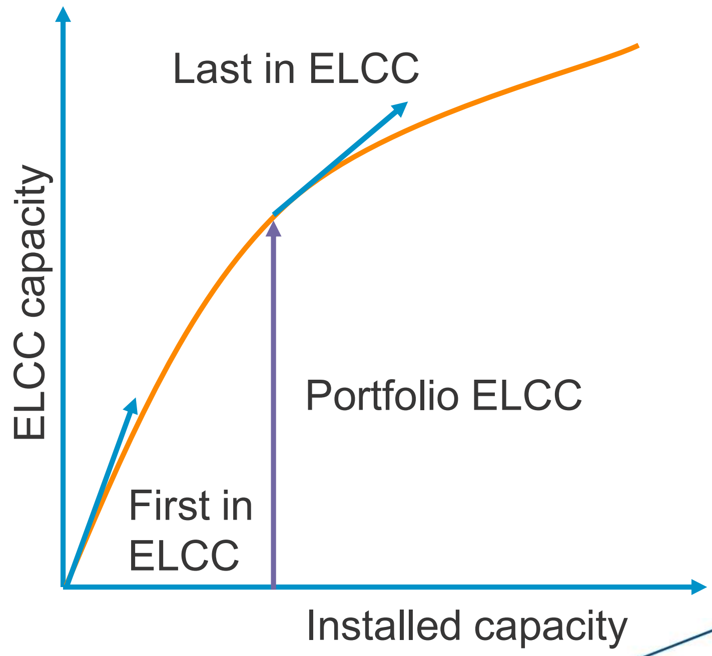
Delta method

Portfolio ELCC (P): Portfolio ELCC is the total ELCC provided by a combination of intermittent and energy-limited resources.

The First-In ELCC (FI_i): The marginal ELCC of each individual resource in a portfolio with no other intermittent or energy-limited resources.

The Last-In ELCC (LI_i): The marginal ELCC of each individual resource when taken in context of the full portfolio.

$$ELCC_i\ (each\ resource) = LI_i + \left(P - \sum_{j=1}^{n} LI_j\right)\left(\frac{LI_i - FI_i}{\sum_{j=1}^{n} LI_j - FI_i}\right)$$

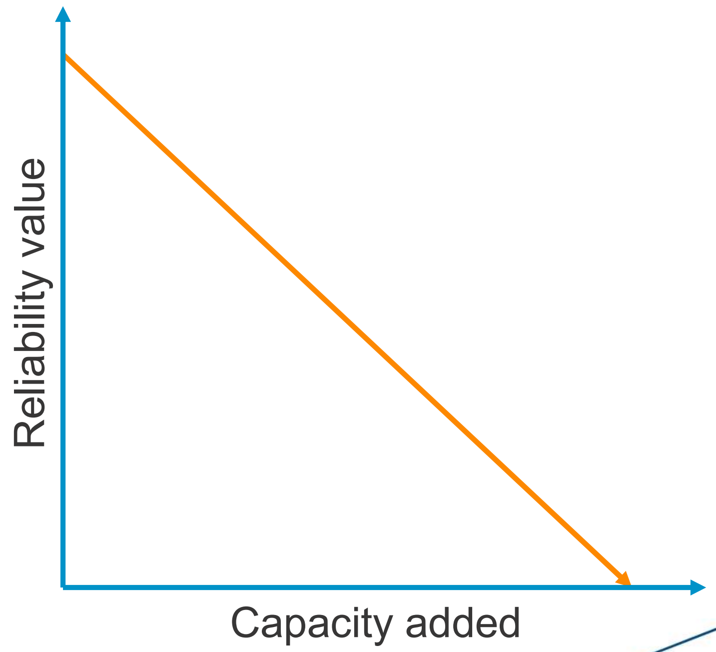


Marginal Reliability Index

A resource's MRI value measures the incremental impact of its 'last' MW on system LOLE, relative to the incremental impact of 'perfect capacity'

- First with base case reflecting the expected system resource mix, including the nameplate capability of the resource class being examined and increase load so $LOLE_1$ is 0.1 days/year.
- Add to the base case an incremental amount of nameplate capability for the resource class being examined $\{\text{x MW}, LOLE_2\}$.
- Add to the base case the same incremental amount of 'perfect capacity' $\{\text{x MW}, LOLE_3\}$ but here $LOLE_3 < LOLE_2$

$$\boldsymbol{MRI = \frac{(0.1 - LOLE_2)}{(0.1 - LOLE_3)}}$$



Equivalent Firm Capacity

An EFC is defined as the precise amount of perfectly reliable firm capacity a resource can displace while maintaining the exact same level of risk on the system

- First the LOLE is noted with base case reflecting the expected system resource mix, including the nameplate capability of the resource class being examined.
- A certain amount of perfect capacity is added in the place of resource class being examined until LOLE is back to previous amount.

$$\boldsymbol{LOLE(R \cup \{i\}) = LOLE(R \cup efr_R(i))}$$

Similarities

- MRI and EFC are similar. Both measure the reliability by replacing intermittent facility class with firm generation capacity (perfect capacity):
  - In **MRI**, the **difference in LOLE** is calculated when **x MW** of intermittent is replaced with **x MW** of perfect capacity
  - In **EFC**, the **LOLE is kept the same** by replacing **x MW** of intermittent with **y MW** of perfect capacity
- ELCC and EFC are also similar. Both measure the capability of the resource by keeping the LOLE constant:
  - In **EFC**, the **LOLE is kept the same** when **x MW** of intermittent is replaced with **y MW** of perfect capacity
  - In **ELCC**, the **LOLE is kept the same** by adding **y MW** of load for the addition of **x MW** of intermittent

ELCC Methodology – Dealing with Volatility

Because the modelling is mostly forward looking, it is geared towards informing long term average outcomes. Parked for now are volatility issues relating to intermittent facilities:

- Volatility of outcomes unrelated to performance or external changes (e.g. underlying load)
- Correlation between weather and load and renewable generation
- Small sample of historical system stress events (meaning new system stress events potentially having a large effect on the outcome from year to year).

Options for mitigating volatility include:

- Excluding events outside the planning criterion from the input dataset
- Adjusting intermittent facility performance for outliers (either at participant request or AEMO discretion)
- Adjusting demand based on other criteria to simulate additional system stress events.

ELCC Assessment for the WEM

- ELCC would be calculated for individual facilities, not facility classes
- The delta method would be used to account for and distribute fleet effects
- Assume storage and demand side resources are used to maximise peak shaving.
- Analysis will use *forecast* demand traces (consistent with other modelling)
- Modelling will not include differential treatment for existing and proposed facilities. In practice we could adopt a similar approach to the NAQ assessment, where AEMO first calculates ELCC for the existing/committed fleet, and then for new facilities, to avoid having ELCC reduced by new facilities.
- Assessment will consider potential for time differentiation by extracting monthly and quarterly CRC values (requested by working group).
- Assessment will consider whether 41 degrees is still the relevant ambient temperature.
- Analysis will consider methods to mitigate volatility (see previous slide).

Capacity Valuation

Installed capacity (ICAP)

- Physical generating capacity adjusted to ambient weather conditions
- 1 MW of ICAP across resources does not provide same reliability

  E.g., $\boldsymbol{Coal} \neq \boldsymbol{Gas} \neq \boldsymbol{Wind}\ (\boldsymbol{MW\ ICAP})$

- So $\boldsymbol{ICAP} = \boldsymbol{UCAP}$ for variable resources given their intermittent nature
- Using ICAP rather than UCAP has the risk of rewarding poorer performing resources, or procuring capacity from facilities that are not available when needed.

Unforced Capacity (UCAP)

- Generating capacity available after forced outage rate (EFORd) taken into account

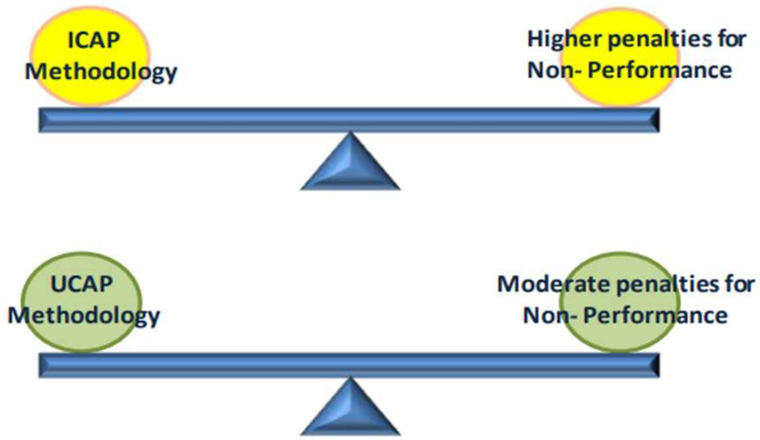
  $\boldsymbol{UCAP} = \boldsymbol{ICAP} * (\textbf{1− unit's EFORd})$

- EFORd accounts for unit runtime
- UCAP creates stronger alignment between the product procured and the product expected to be delivered
- 1 MW of UCAP is a comparable product/service across all capacity providers

  E.g., $\boldsymbol{Coal} = \boldsymbol{Gas} = \boldsymbol{Wind}\ (\boldsymbol{MW\ UCAP})$

ICAP v UCAP: Issues

- Since ICAP does not account for failure probabilities for individual generators – penalties for non-performance need to be stronger to ensure in the same level of system reliability.
- UCAP bases capacity allocation based on historic performance and will not necessarily reflect future performance.



- Participants would need to be able to submit that certain outages are one off and should not be incorporated into historic outage rate
- Need to consider method to determine EFORd for facilities which are seldom dispatched.

ICAP vs UCAP: Assumptions

We will calculate the effect on CRC allocation *for non-intermittent generators* of:

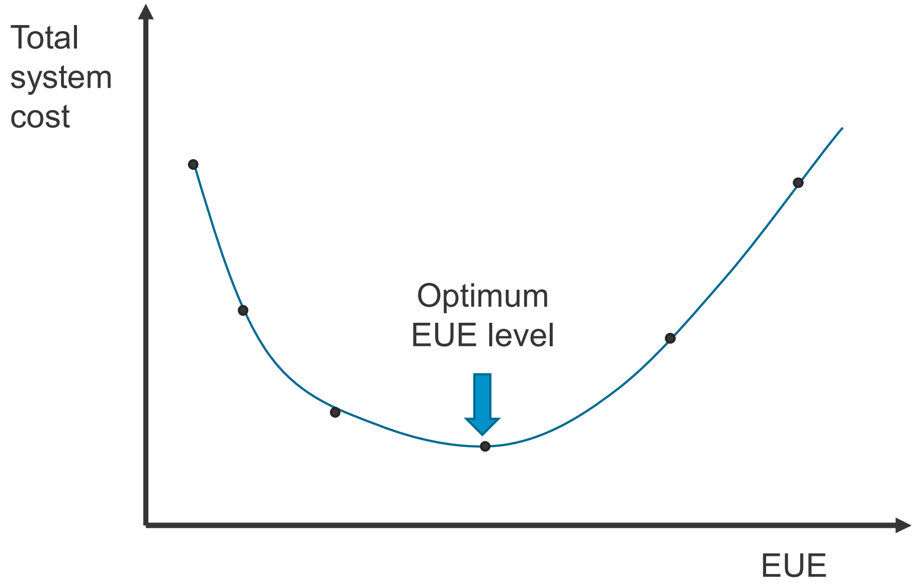
- ICAP
  - Assumes facilities are fully available
  - Peak limb of planning criterion includes consideration of expected outage rate
  - Refunds paid for planned outages above a threshold, and forced outages (as now)
- UCAP
  - Probabilistic method assumes stochastic outages with EFORd based on historic facility outage rates (or class average for new facilities), but facilities are otherwise fully available.
  - Peak limb of planning criterion does not account for expected outages, only for single largest contingency.
  - Refunds paid only when actual (planned + forced) rate exceeds expected rate

Recap: Approach to Revising the Planning Criterion

To determine an appropriate metric for each limb of the planning criterion, we need to explore the trade-off between higher reliability requirements and cost (noting that the outcome of the review should not erode the current reliability standard).

For the EUE limb the methodology would be as follows:

1. Determine the lowest cost new entrant technology (previous studies assumed an OCGT, could be PV + storage)
2. Determine a Value of Customer Reliability (VCR) for the SWIS (used Western Power value)
3. Perform system adequacy modelling (CAPSIM) with various levels of new capacity of the type determined in step 1 to determine the level of EUE (in MWh)
4. Determine total system cost at each level of new capacity, as EUE x VCR + cost of new capacity
5. Chart total system cost vs EUE, and determine the level of EUE at which minimum total system cost occurs.



Appendix: Additional detail on Planning Criterion

Planning criterion reserve margin – more detail

4.5.9(a)…plus a reserve margin equal to the greater of:

(i) 7.6% of the forecast peak demand (including transmission losses and allowing for Intermittent Loads); and

(ii) the maximum capacity, measured at 41°C, of the largest generating unit; …

Subclause (i) accounts for the use of an ICAP based CRC method, and reflects the expected quantity of forced outage at system peak. Subclause (ii) reflects the need to maintain sufficient capacity to meet Spinning Reserve requirements.

Subclause (i) would not be needed under a UCAP approach to CRC allocation, and in any case could be improved by replacing the hardcoded percentage with a methodology.

Subclause (ii) no longer accurately captures the largest contingency on the power system, as the spinning reserve requirement can now be set by a network contingency.

Appendix: Additional Detail on Flexible Capacity Product

What is flexible capacity?

The flexible capacity product would procure MW of capacity to collectively meet:

- a defined minimum ramp requirement;
- maintained over a defined duration.

To be certified to provide flexible capacity, a facility must be able to show:

- What MW quantity it can ramp over the defined time period
- How long it can sustain that ramp for, and whether it differs at different times of day.

In addition, to be eligible for certification, the facility would need to have:

- short start, load, and stop times
- firm capacity
- low or zero minimum generation level

A large facility with a low ramp rate would be unlikely to receive flexible CRC for its full capacity, but only for the MW it could move in the defined period.

Procurement of Two Capacity Products

It is possible that there would be sufficient capacity to meet ramping needs even without explicitly paying for flexibility. A flexible capacity product would need to:

- Procure service only where it is needed
- Incentivize participants to make capacity available for both products (prevent withholding)
- Have a BRCP and pricing structure that accounts for payments for peak capacity

Facilities would apply for CRC for both types of capacity at the same time, with upgrades distinct from existing capacity as is the case today.

When allocating capacity credits, AEMO would procure capacity for both products. It is not yet clear whether it would do so in sequence (peak capacity first, then procuring flexible capacity only if the already procured fleet does not meet the flexible capacity target) or in parallel (to ensure the lowest overall cost).

Where flexible capacity has a non-zero price, both existing and new facilities would receive it, and facilities providing flexibility would have a fixed price option to lock in pricing for multiple years.

The working group expressed a need to not prefer one product over another when the system needs both.

Appendix: Additional Detail on Capacity Obligations

Proposed changes to capacity obligations

- Participants would nominate their own fuel storage duration, which would be accounted for in ELCC calculations and Capability Class allocation.
- Any technology can nominate for any capability class. This includes DSPs and pure intermittent generators. Facilities would need to provide evidence to support their nominated class (particularly their ability to meet availability obligations), and could be placed in another class if performance does not match certification.
- Unrestricted firm capacity (class 1) would have availability obligations in all obligation hours.
- Restricted firm capacity (class 2) would have availability obligations in all obligation hours
- Non-firm capacity (class 3) would have no availability obligations (but would expect to receive proportionally fewer capacity credits than other classes)
- Availability Hours may differ for the two products, and may overlap. If the same MW of capacity was providing both products, it would have both sets of obligations.

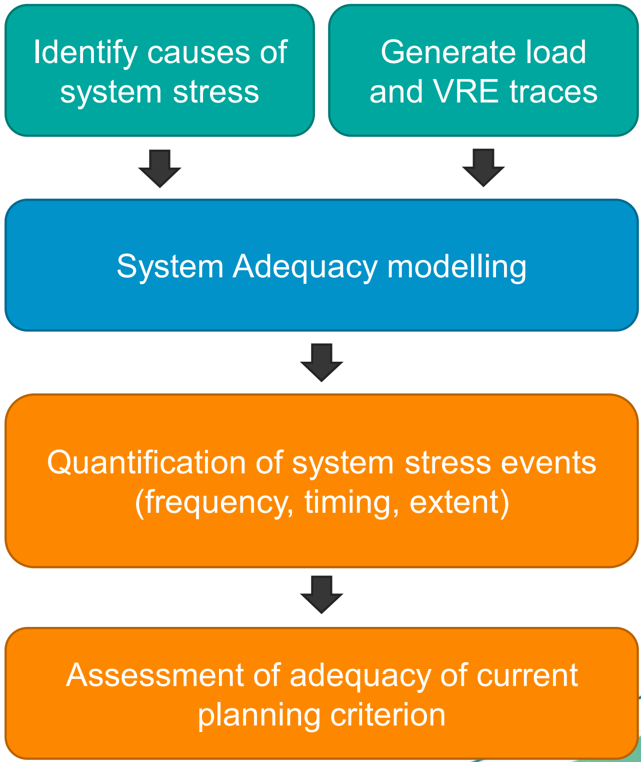
Appendix: Updated system stress modelling outputs

Modelling Methodology – Recap

System Stress Modelling Objectives:

- Identify causes of system stress – current and future.
- Quantify how the current generation mix (and other capacity sources) accommodate the identified types of system stress under credible demand scenarios (current, 2030 and 2050) and identify any deficiencies.
- Assess whether the current Planning Criterion is adequate for meeting the capacity requirements of the SWIS.
- Modelling focuses on expected unserved energy under each scenario.

System Stress Modelling Methodology:



Modelling Methodology – Scenarios

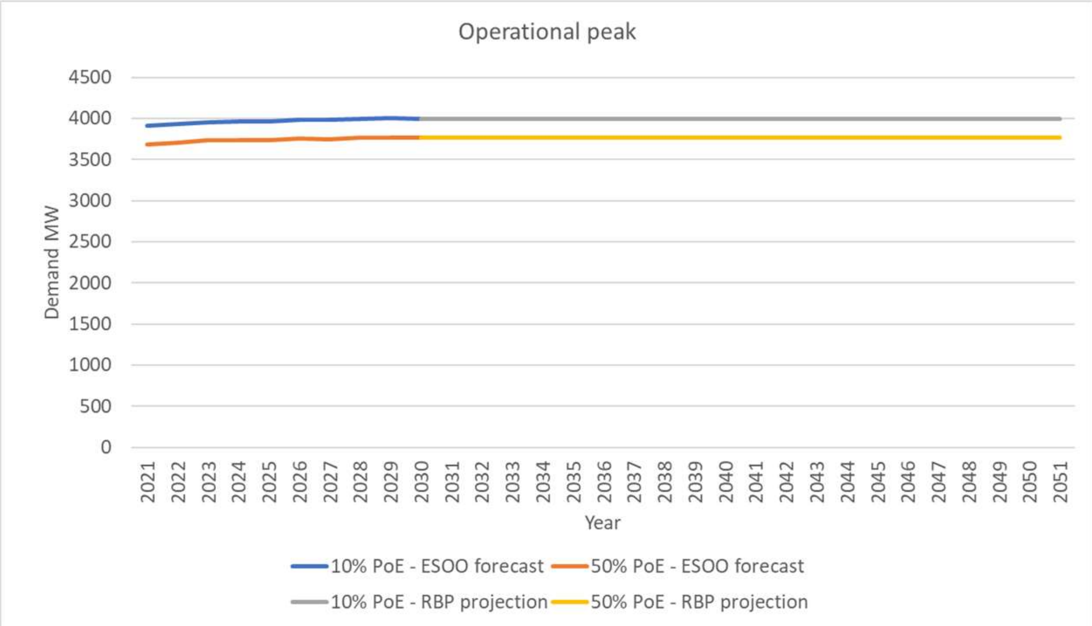
Retirement Scenarios:

	2022	2030	2050
R1	Current capacity mix	Muja retires on schedule	All thermal plant retired
R2		All thermal baseload plant retires	

New Build Scenarios:

	2022	2030	2050
S1	Current capacity mix	New capacity as required in line with respective 2050 targets	Sufficient PV + wind by 2050 to meet energy requirement. Large storage capacity Some demand flexibility
S2			PV + Wind overbuild by 2050 reducing amount of storage required Less storage capacity Large demand flexibility
S3			Sufficient PV + wind by 2050 to meet energy requirement Green H2 thermal Some storage Some demand flexibility

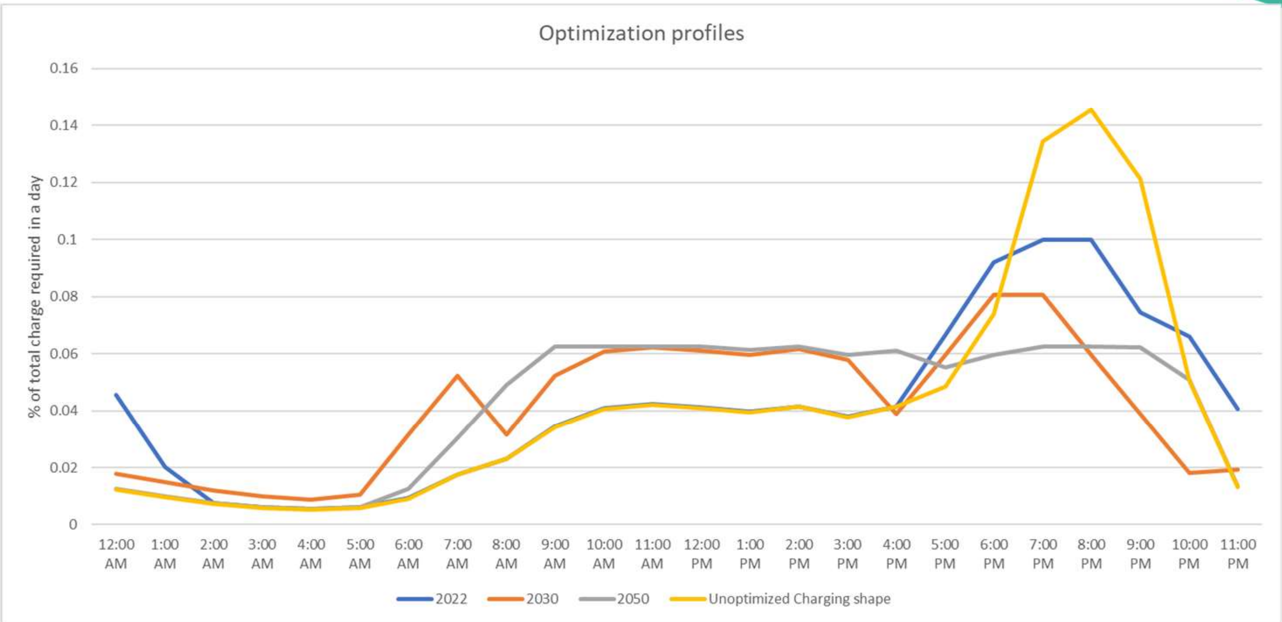
ESOO Load Forecast



Year	10% POE (MW)	50% POE (MW)
2022	3936	3700
2030	4000	3772
2050	4000	3772

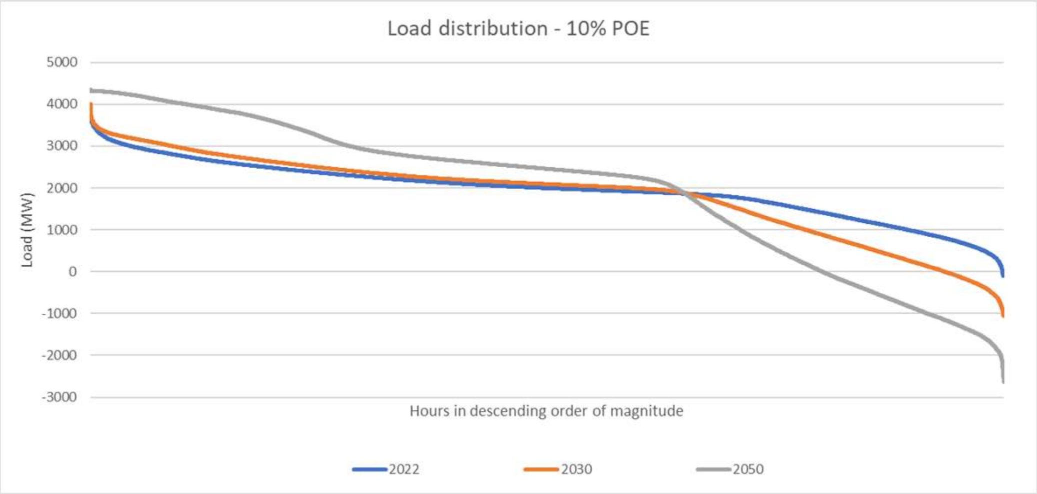
- 2021 ESOO forecasts operational demand until CY 2030 and we have extended the forecast until 2050. We have capped the operational demand to account for the accelerated increase in BTM solar uptake.
- In 2050, EV demand is significant and hence the load value is greater than the operational demand forecast.

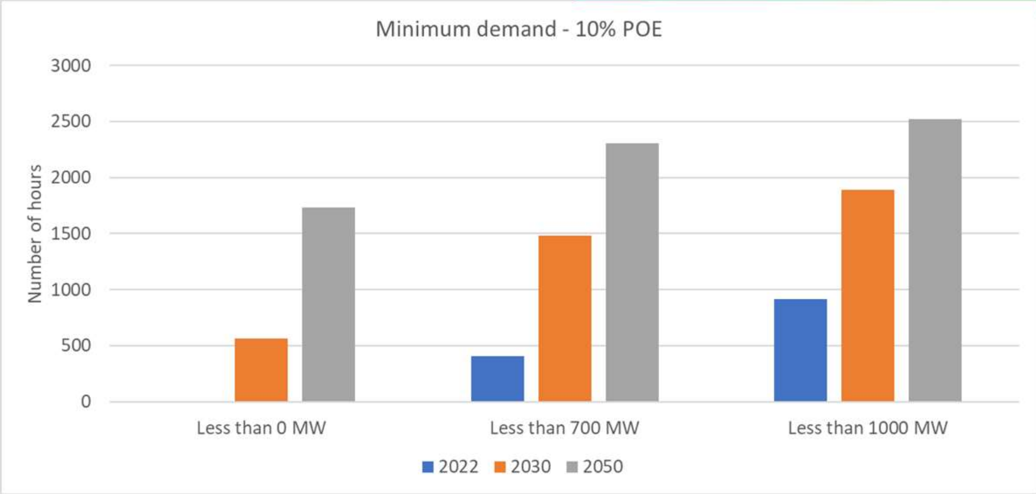
EV changing pattern



- The EV uptake and EV charging pattern is modelled is based on ESOO/CSIRO model (unoptimized charging shape).
- We have separately developed an optimization model to spread out EV charging. This reflects an assumption that there will be at least some off-market optimisation of charging times.
- To accommodate technology maturity, we have improved the effectiveness of the optimization in steps over 2022, 2030 and 2050.

Modelling Results – Load Analysis (10% POE)





Year	Maximum demand (MW)	Minimum demand (MW)
2022	3937	-98
2030	4002	-1021
2050	4346	-2600

AEMO have previously cited 700 MW as the minimum level of operational demand for system stability – see https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/2019/Integrating-Utility-scale-Renewables-and-DER-in-the-SWIS.pdf

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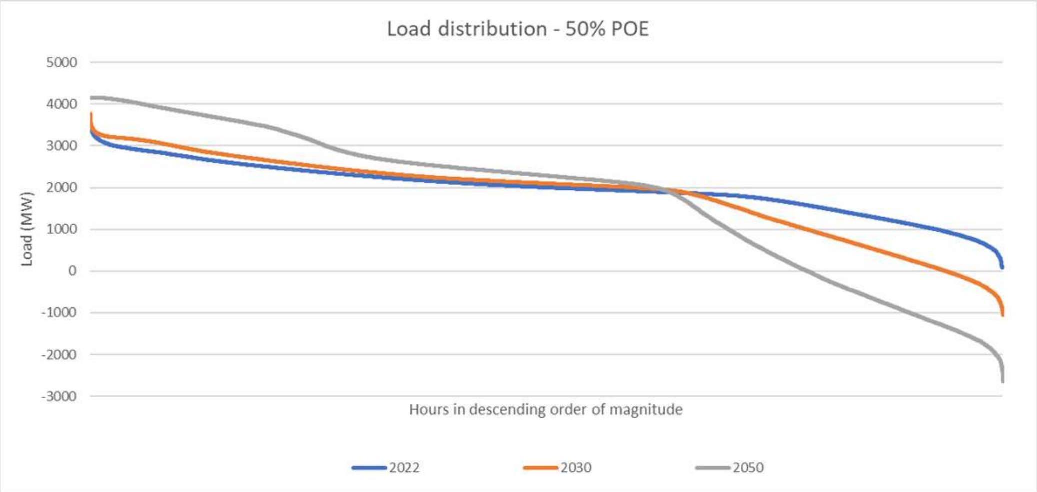
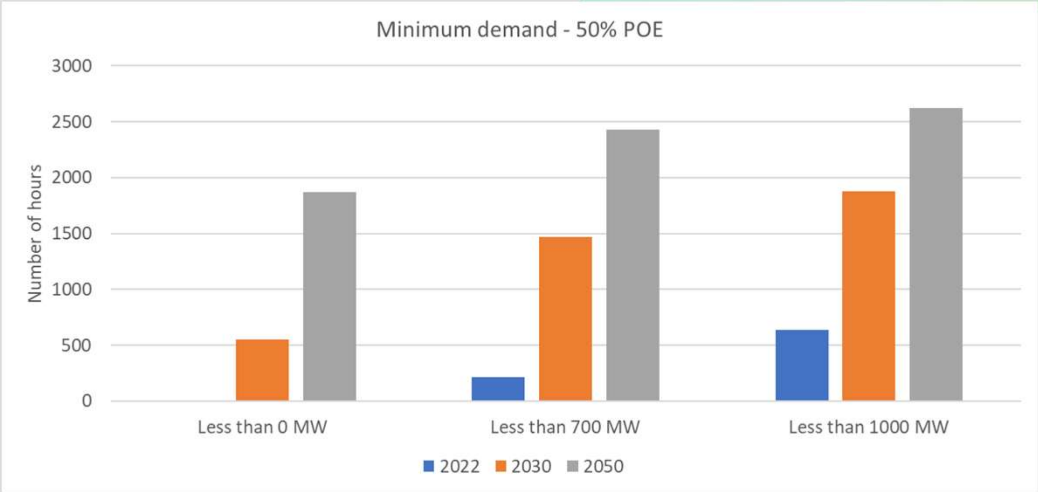
Modelling Results – Load Analysis (50% POE)



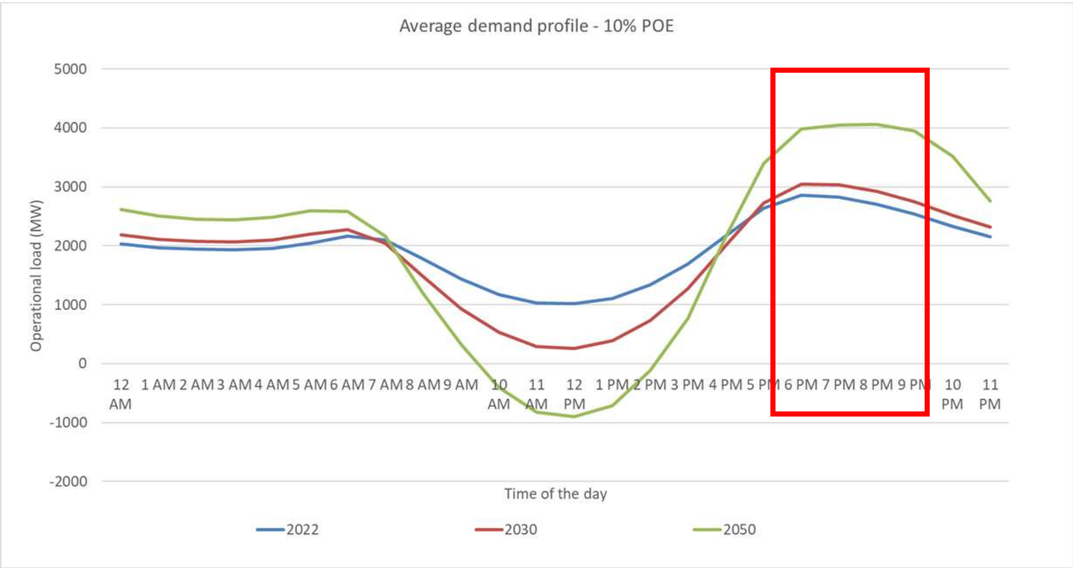


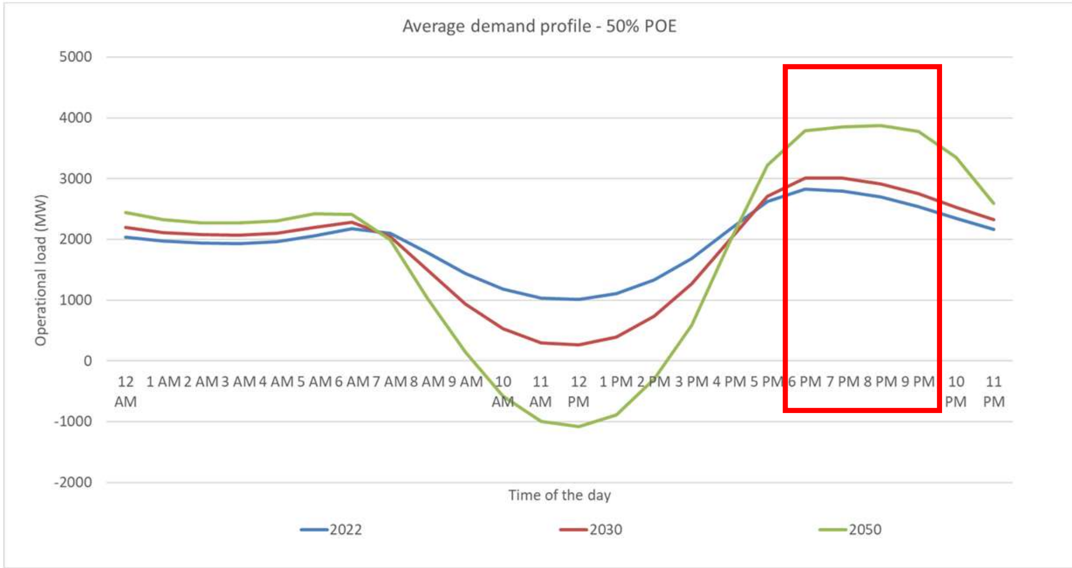
Year	Maximum demand (MW)	Minimum demand (MW)
2022	3686	-110
2030	3770	-1059
2050	4159	-2635

- Incentives needed to deal with minimum demand before 2030.
- Significant management of minimum demand needed in 2050.
- By 2050, operational demand is less than 700 MW for 2400 hours per year (27% of all periods).

Modelling Results – Evolving Demand Shape

System peak becomes later and flatter by 2050, occurring from 6:00pm to 9:00pm:

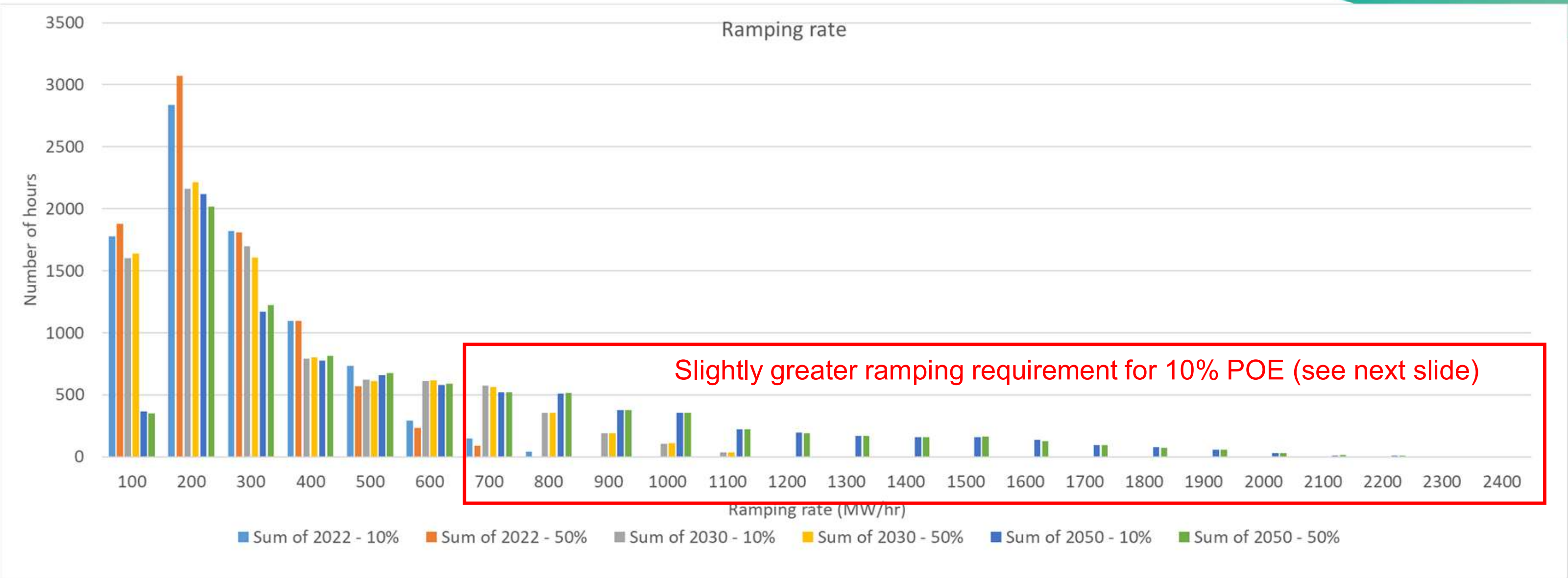




Year	Maximum demand (MW)	Minimum demand (MW)
2022	2858 – **6:00pm**	1013 – **12:00pm**
2030	3043 – **6:00pm**	262 – **12:00pm**
2050	4060 – **8:00 pm**	-903 – **12:00pm**
Periods of peak demand	**6:00pm – 9:00pm**	

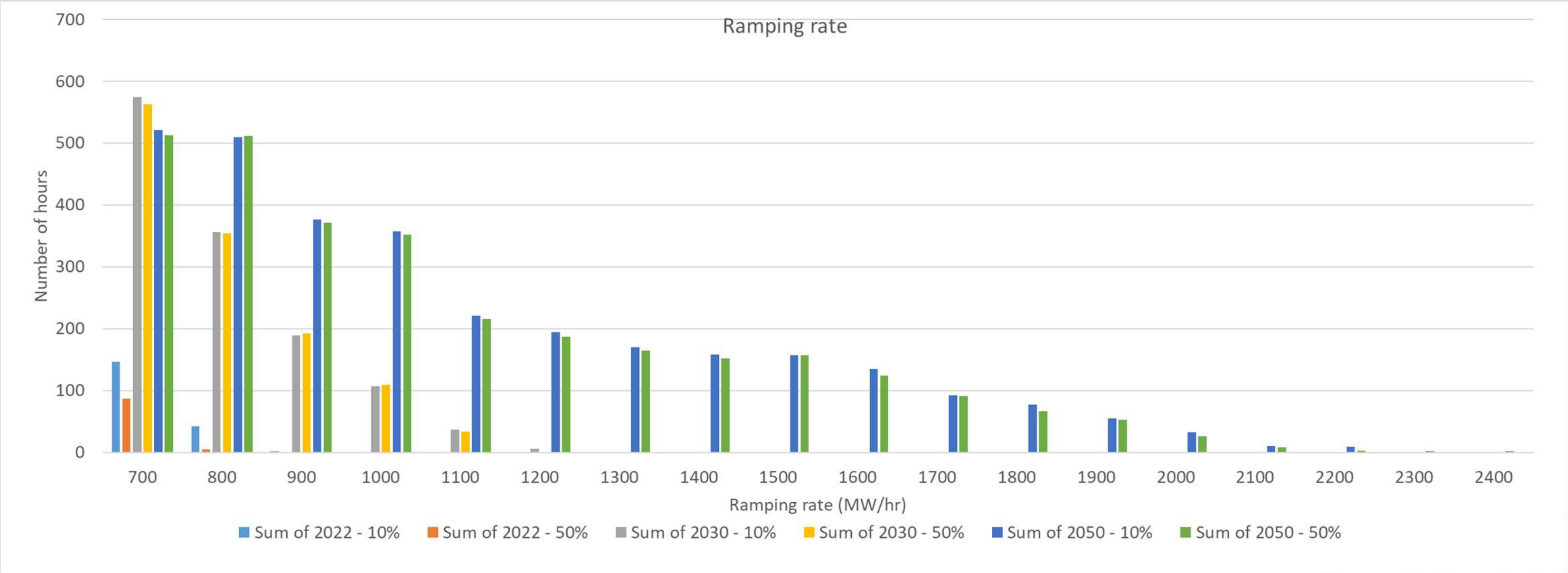
Year	Maximum demand (MW)	Minimum demand (MW)
2022	2824 – **6:00pm**	1016 – **12:00 pm**
2030	3012 – **6:00pm**	265 – **12:00pm**
2050	3876 – **8:00pm**	-1075 – **12:00pm**
Periods of peak demand	**6:00pm – 9:00pm**	

Modelling Results – Demand Ramping (1)



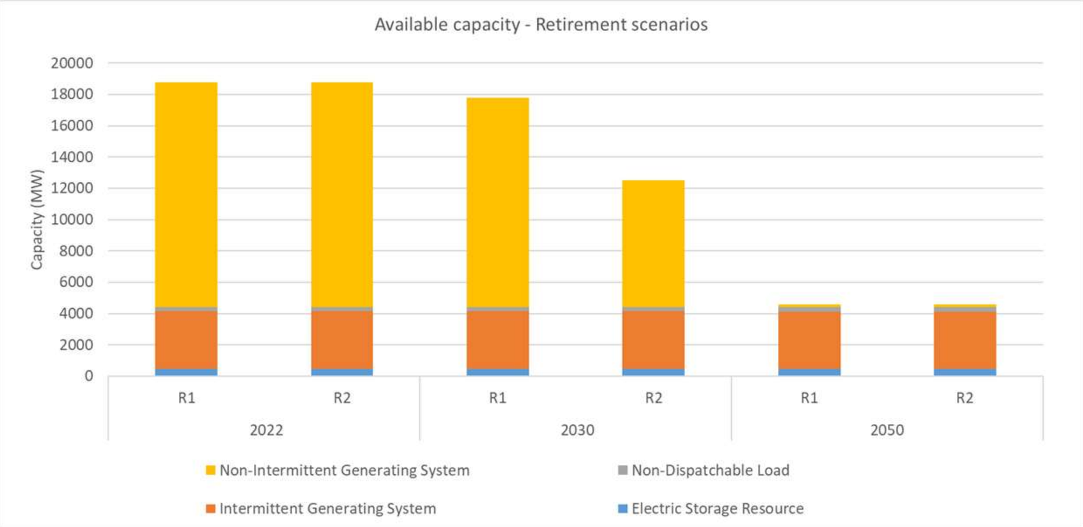
- In later years, much higher demand ramping is experienced.
- In the 50% POE load curve, the number of hours with low ramp rate is high whereas for the 10% POE case, the number of hours with higher ramp rate is higher implying higher ramping requirements for the 10% POE case.
- The highest ramp rates in 2050 are >2000 MW/hr, 3x those in 2022.
- However, these ramp rates are still well within the capabilities of current technologies (e.g. OCGT), as long as sufficient capacity is available.
- By 2050, >2GW of fast-ramping capacity (e.g. OCGT or battery) will be required.
- However, under a zero-emissions policy, options for ramping capacity are much more limited.

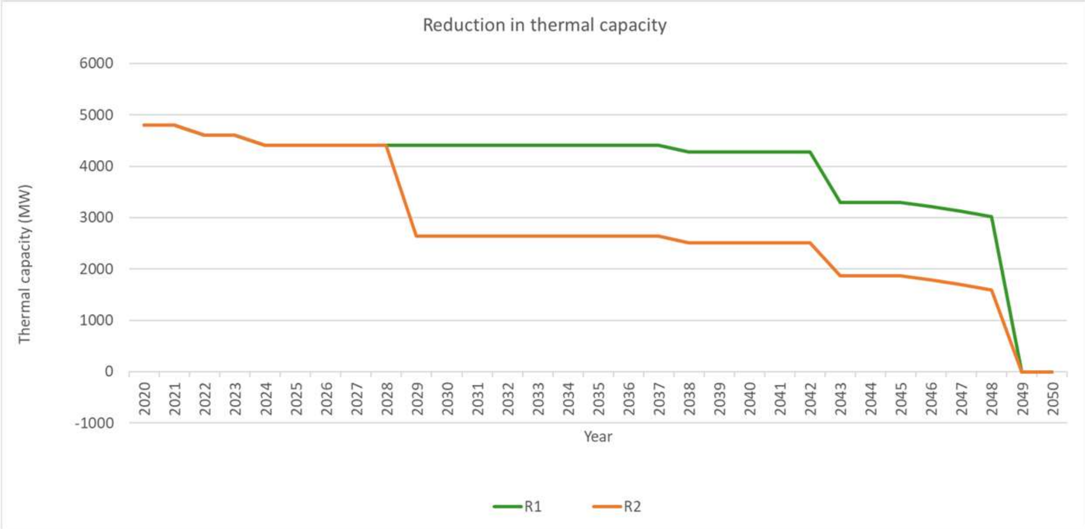
Modelling Results – Demand Ramping (2)



Modelling Results – Capacity Available

Available capacity after retirement of thermals (two scenarios):





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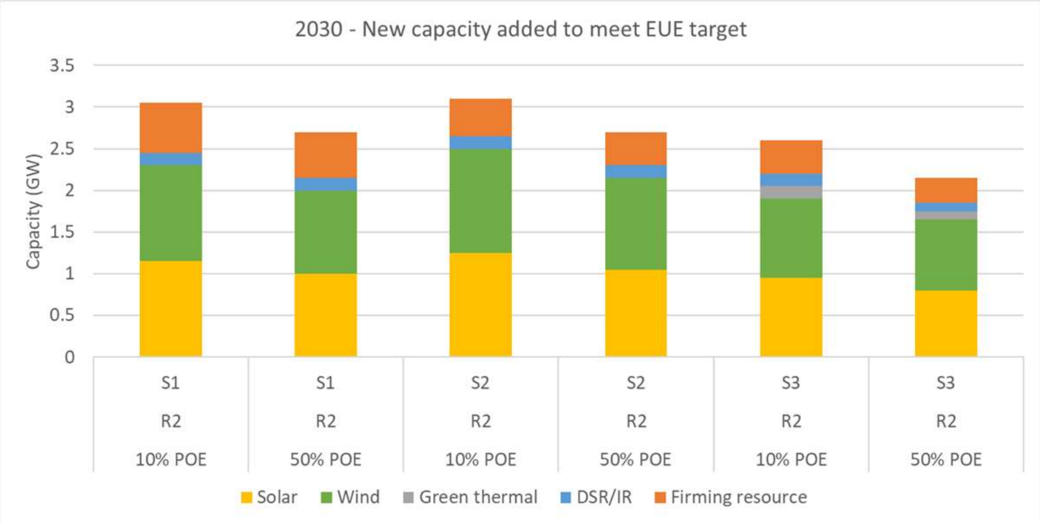
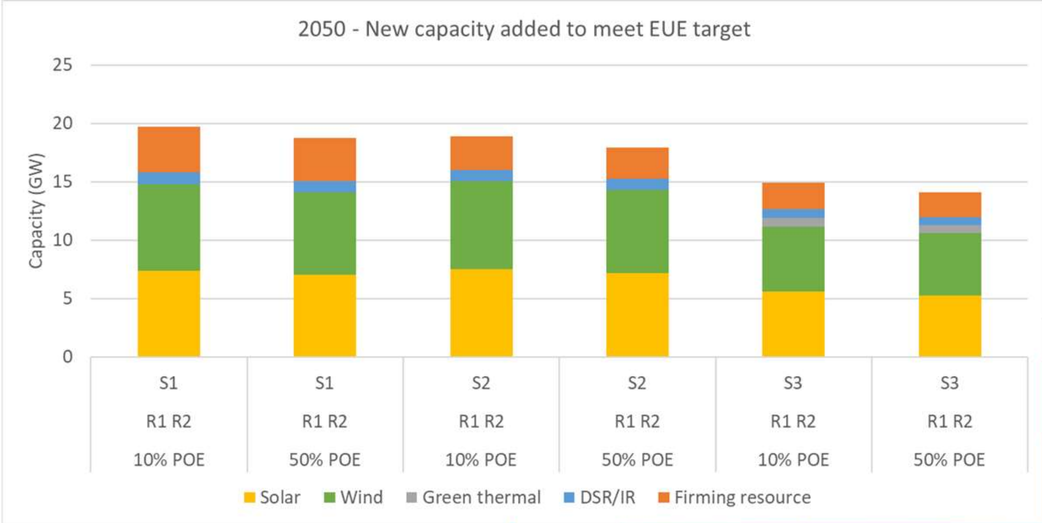
Modelling Results – Capacity Additions

Capacity additions (MW) to achieve unserved energy (EUE) close to current reliability criterion:

Proportion of new capacity added

Scenario	Solar	Wind	DSR/IR	Battery	Green thermal
S1	37.5%	37.5%	5%	20%	0%
S2	40%	40%	5%	15%	0%
S3	37.5%	37.5%	5%	15%	5%





Modelling Results – Unserved Energy – 10% POE

Unserved energy for each capacity year under each of the retirement and new build scenarios

Retirement scenario	Scenario	Year	Solar	Wind	Green thermal	DSR/IR	Firming resource	Additional capacity added	Unserved energy %
R1	S1	2022	0	0	0	0	0	0	0.000021%
		2030	0	0	0	0	0	0	0.000000%
		2050	7400	7400	0	1000	3950	19750	0.002030%
	S2	2022	0	0	0	0	0	0	0.000000%
		2030	0	0	0	0	0	0	0.000000%
		2050	7550	7550	0	950	2850	18850	0.002082%
	S3	2022	0	0	0	0	0	0	0.000000%
		2030	0	0	0	0	0	0	0.000000%
		2050	5600	5550	750	750	2250	14850	0.002016%
R2	S1	2022	0	0	0	0	0	0	0.000021%
		2030	1150	1150	0	150	600	3050	0.002086%
		2050	7400	7400	0	1000	3950	19750	0.002030%
	S2	2022	0	0	0	0	0	0	0.000000%
		2030	1250	1250	0	150	450	3100	0.002068%
		2050	7550	7550	0	950	2850	18850	0.002082%
	S3	2022	0	0	0	0	0	0	0.000000%
		2030	950	950	150	150	400	2550	0.002061%
		2050	5600	5550	750	750	2250	14850	0.002016%

Key		
New build capacity (MW)	Total capacity added (MW)	Unserved Energy (%)

Modelling Results – Unserved Energy – 50% POE

Unserved energy for each capacity year under each of the retirement and new build scenarios

Retirement scenario	Scenario	Year	Solar	Wind	Green thermal	DSR/IR	Firming resource	Additional capacity added	Unserved energy %
R1	S1	2022	0	0	0	0	0	0	0.000000%
		2030	0	0	0	0	0	0	0.000000%
		2050	7050	7050	0	950	3750	18800	0.002011%
	S2	2022	0	0	0	0	0	0	0.000000%
		2030	0	0	0	0	0	0	0.000000%
		2050	7200	7150	0	900	2700	18000	0.001993%
	S3	2022	0	0	0	0	0	0	0.000000%
		2030	0	0	0	0	0	0	0.000000%
		2050	5300	5300	700	700	2100	14150	0.002008%
R2	S1	2022	0	0	0	0	0	0	0.000000%
		2030	1000	1000	0	150	550	2700	0.002096%
		2050	7050	7050	0	950	3750	18800	0.002011%
	S2	2022	0	0	0	0	0	0	0.000000%
		2030	1050	1100	0	150	400	2650	0.002090%
		2050	7200	7150	0	900	2700	18000	0.001993%
	S3	2022	0	0	0	0	0	0	0.000000%
		2030	800	850	100	100	300	2200	0.002075%
		2050	5300	5300	700	700	2100	14150	0.002008%

Key		
New build capacity (MW)	Total capacity added (MW)	Unserved Energy (%)

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Modelling Results – Capacity Additions

Key findings (50% POE):

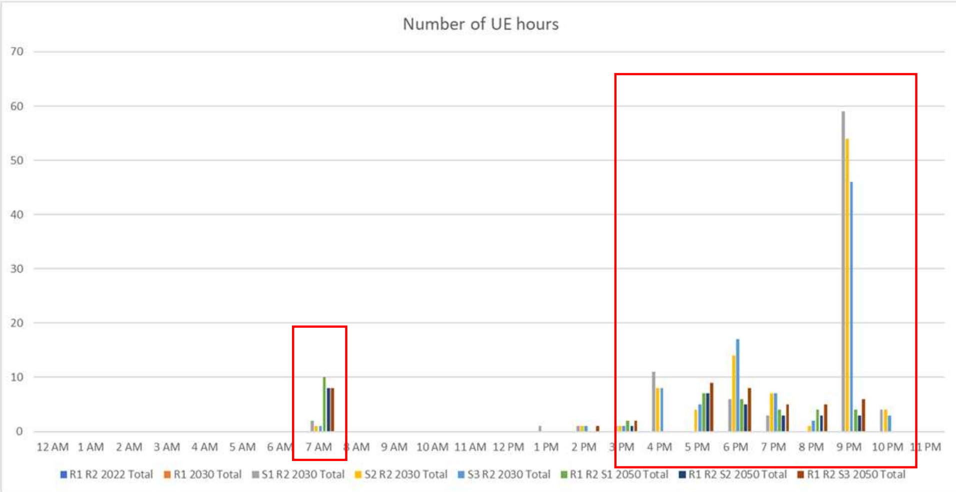
- Current excess of capacity in 2022.
- Under retirement scenario R1 (Muja retires as planned), no additional capacity is required in 2030, and zero EUE results. Under retirement scenario R2 (all thermal baseload plant retires by 2030), >800 MW renewables build is required, plus storage/DSM to balance.
- New build scenario S1 (sufficient PV + wind by 2050 to meet energy requirement) requires >0.5 GW firming resource in 2030 and >3.5 GW firming resource in 2050 to avoid excessive EUE.
- New build scenario S2 (PV + wind overbuild by 2050 reducing amount of storage required) requires 0.4 GW firming resource in 2030 and >2.5 GW firming resource in 2050 to avoid excessive EUE.
- New build scenario S3 (Sufficient PV + wind) requires much lesser storage as a firm green thermal capacity such as H_2 is available.

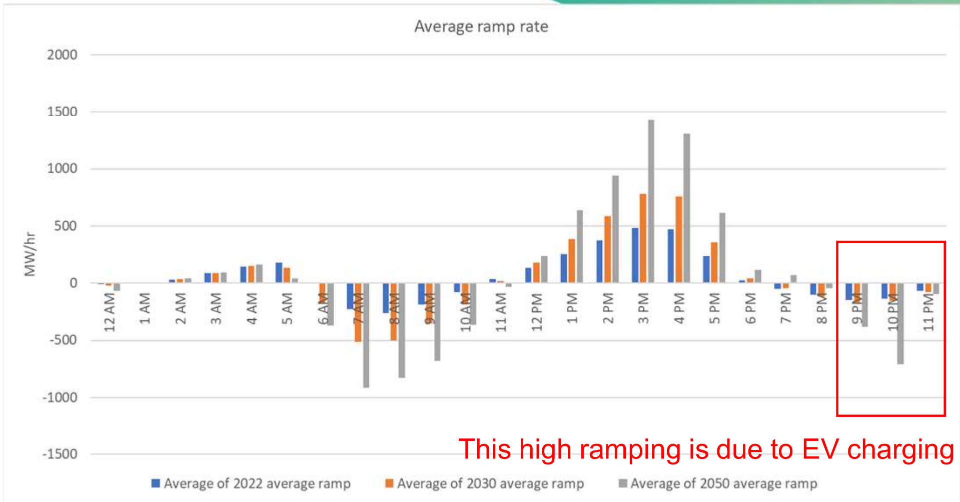
Comparing 10% POE and 50% POE:

- Higher ramping and peak demand is experienced in 10% POE case (as expected).
- Capacity added to retain the UE% at 0.002% is higher for 10% POE. Around 400 MW additional capacity added in 2030 and 1000 MW in 2050 when compared to 50% POE.

	2030			2050		
10% POE capacity additions	**S1**	**S2**	**S3**	**S1**	**S2**	**S3**
Intermittent (Wind + Solar) (MW)	2300	2500	1100	14800	15100	11150
Firming resource (MW)	600	450	400	3950	2850	2250

When do we need capacity to be available?





Historically, the RCM was designed to ensure availability of market dispatchable capacity across the entire duration of a hot summer peak demand day.

By the mid 2020s, the SWIS will have sufficient behind the meter solar penetration that unserved energy due to lack of capacity is *extremely* unlikely in the middle of the day.

The evening peak will be flattened and extended in duration.

We need to make sure the fleet includes facilities which provide capacity in the evening when solar output is low, and in the morning (before BTM solar ramps up).

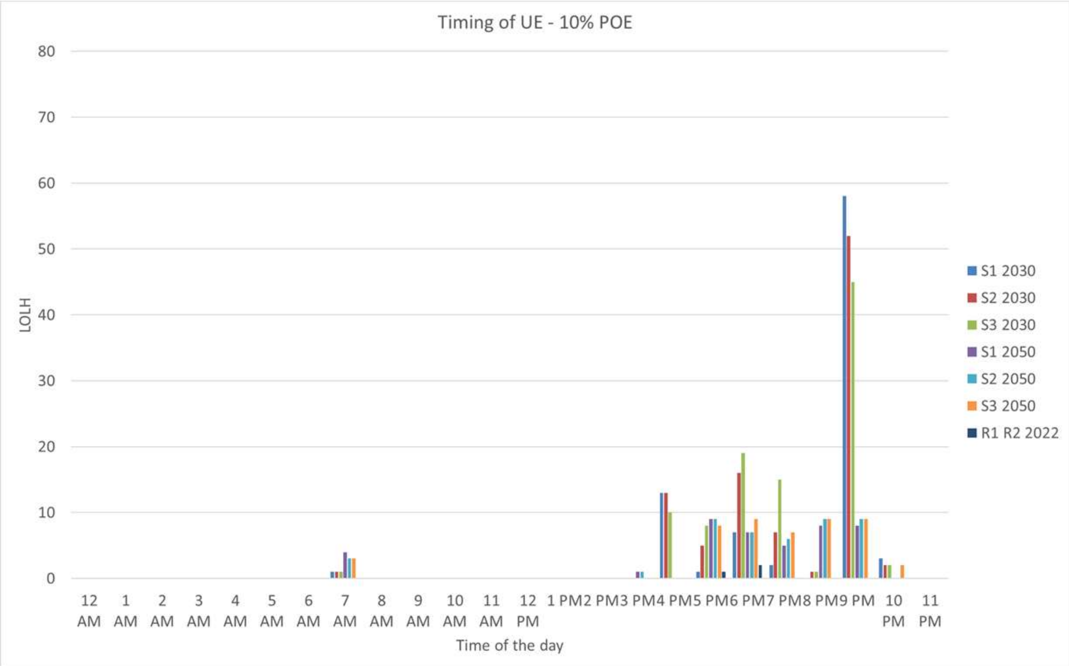
It will be important to have facilities that can ramp up fast in the evening, and facilities that can ramp down fast in the morning.

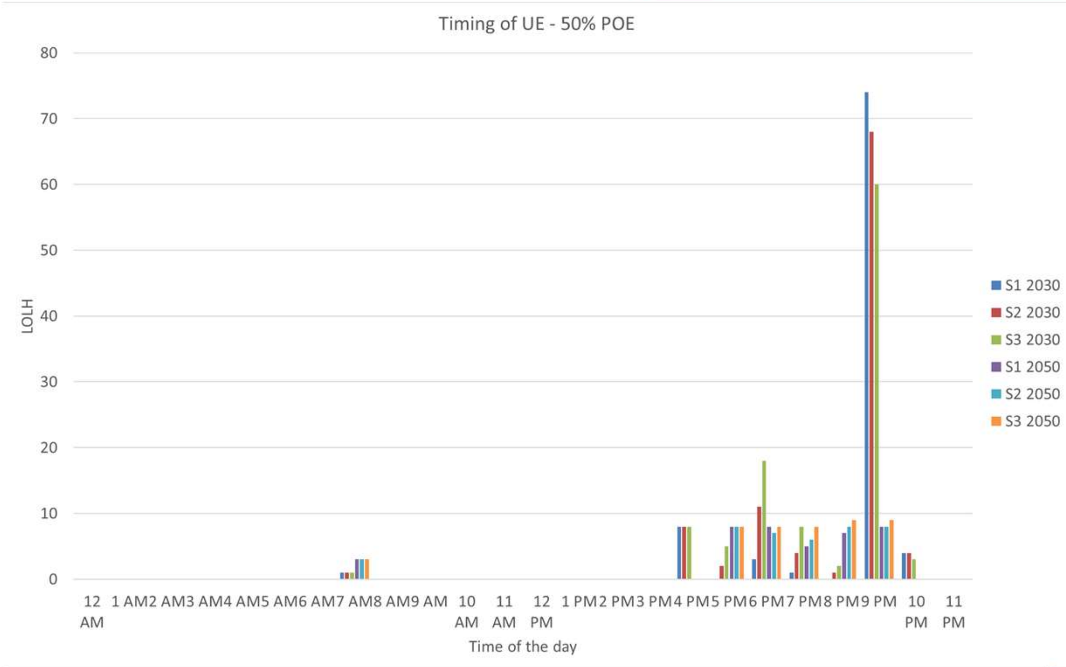
In future intermittent generators may be well placed to provide fast ramping service in both directions as they increasingly pre-curtail.

These charts assume some spread of EV charging times (see slide 62). The working group asked to also model a scenario with no DER optimisation.

Modelling Results – Timing of Unserved Energy

Unserved energy events concentrated around evening and the morning periods

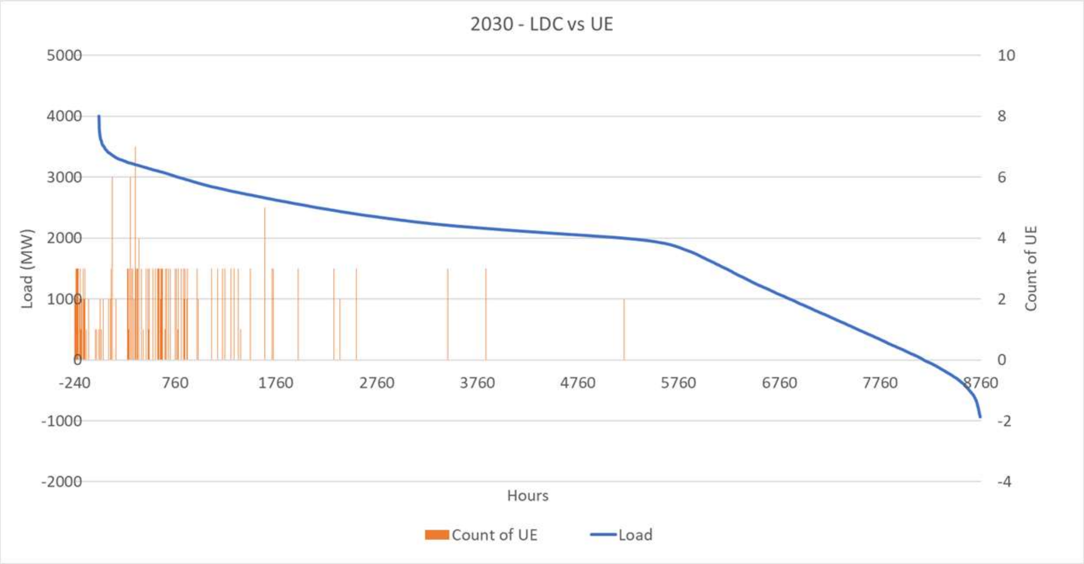


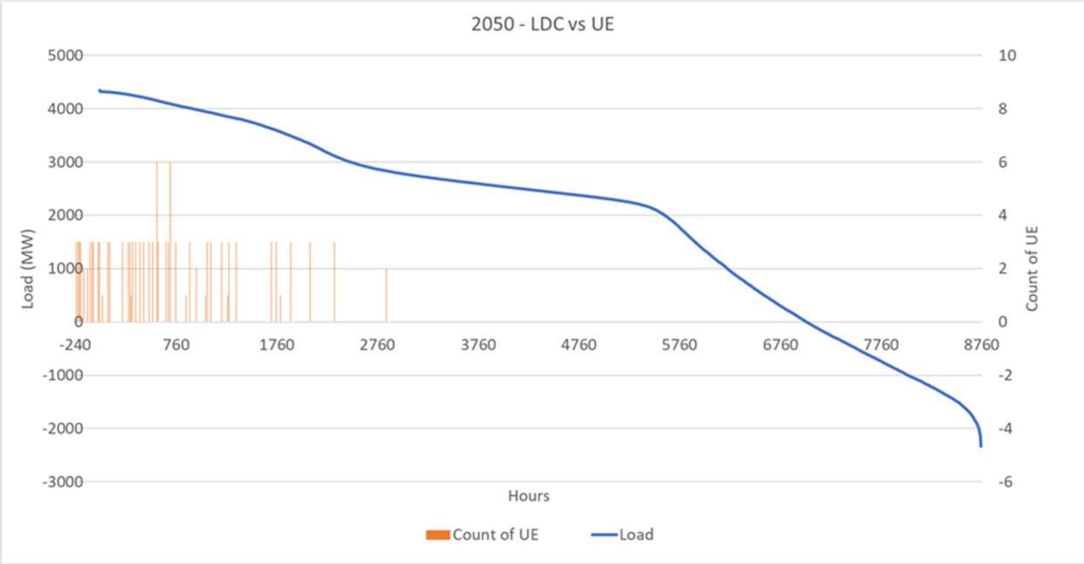


- In 2050, the EUE is distributed over several periods whereas in 2030, EUE is mostly concentrated at 9:00pm (next couple of slides).
- UE at 7:00am because of unavailability of battery and low solar output.
- The EUE at 9:00pm is greater in 50% POE case compared to 10% POE because UE is distributed over several hours and also due to the different capacity resources added in the 10% POE case.
- Around 75% of the UE is during periods of peak demand (6:00pm – 9:00pm)

Modelling results – Load vs UE – 10% POE

Most UE is experienced during periods of high load (including system peak) in 2030 and 2050

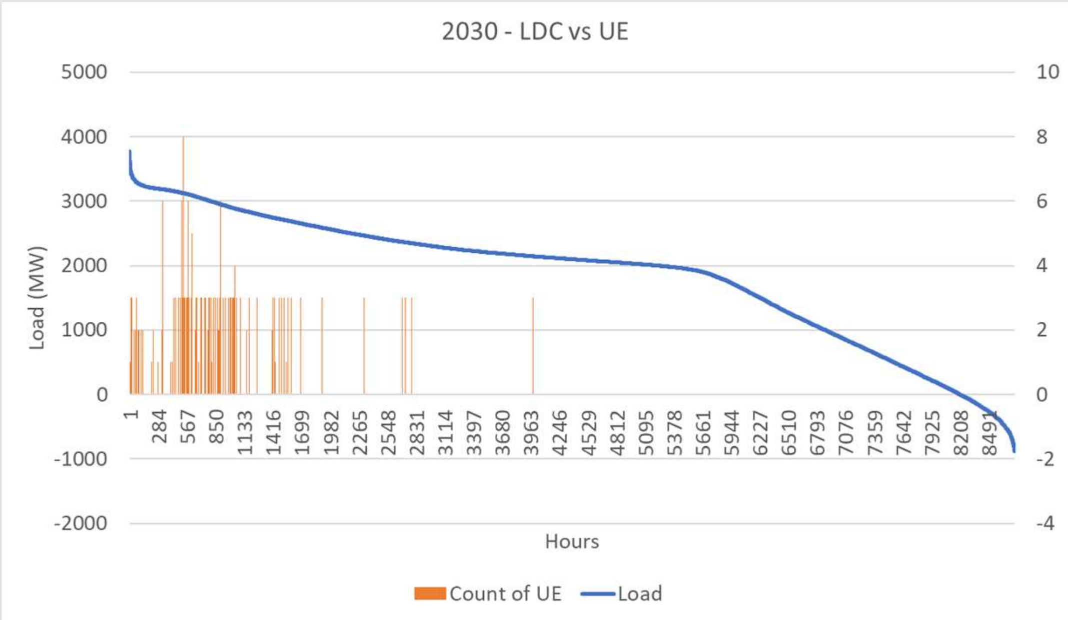


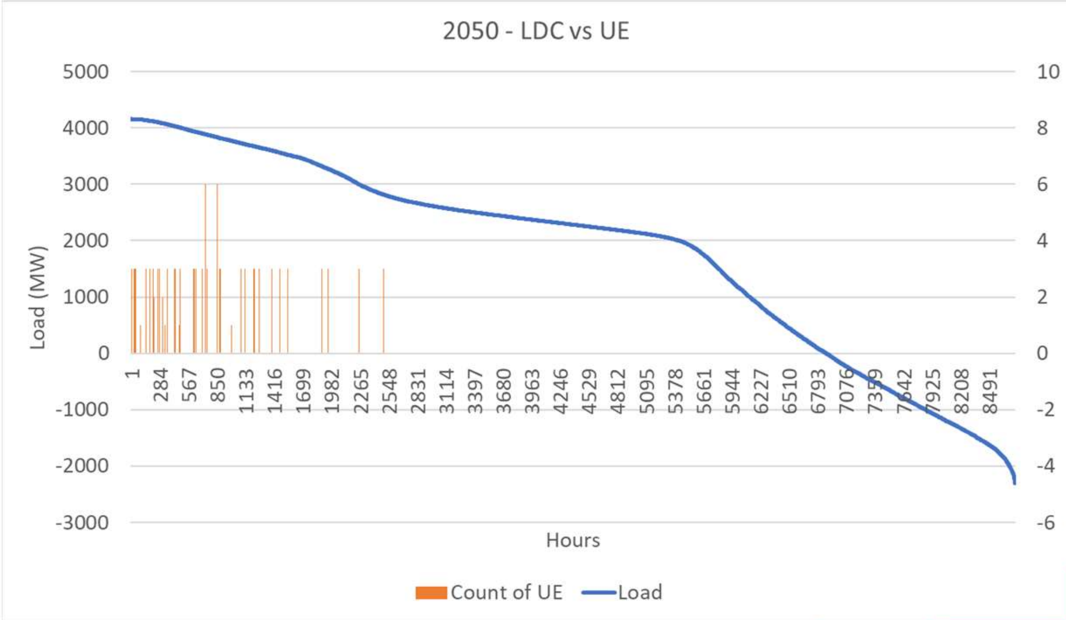


This (EUE-based) modelling shows that system peak still has relatively high likelihood of a lost load event. This confirms the need to retain a peak load limb to ensure reliability is maintained at at least the same level as today.

Modelling results – Load vs UE – 50% POE

Most UE is experienced during periods of high load (including system peak) in 2030 and 2050





Modelling Results – Measurement of Unserved Energy (1)

Amount of total unserved energy according to the hour of the day **(MWh)**

10% POE

Time	S1 2030	S2 2030	S3 2030	S1 2050	S2 2050	S3 2050	R1 R2 2022
12 AM							
1 AM							
2 AM							
3 AM							
4 AM							
5 AM							
6 AM							
7 AM	9.2	5.8	5.9	101.2	103.3	59.6	
8 AM							
9 AM							
10 AM							
11 AM							
12 PM							
1 PM							
2 PM							
3 PM				0.5	1.4		
4 PM	190.7	128.5	112.5				
5 PM	13.6	36.6	55.6	349.1	356.4	272.7	8.8
6 PM	103.7	389.9	534.8	569.6	574.7	585.3	9.2
7 PM	15.6	73.0	162.4	217.6	233.3	233.0	
8 PM		1.2	6.1	292.6	305.1	315.4	
9 PM	1331.5	1021.7	776.3	211.4	212.3	259.7	
10 PM	21.6	14.0	11.4			4.0	
11 PM							

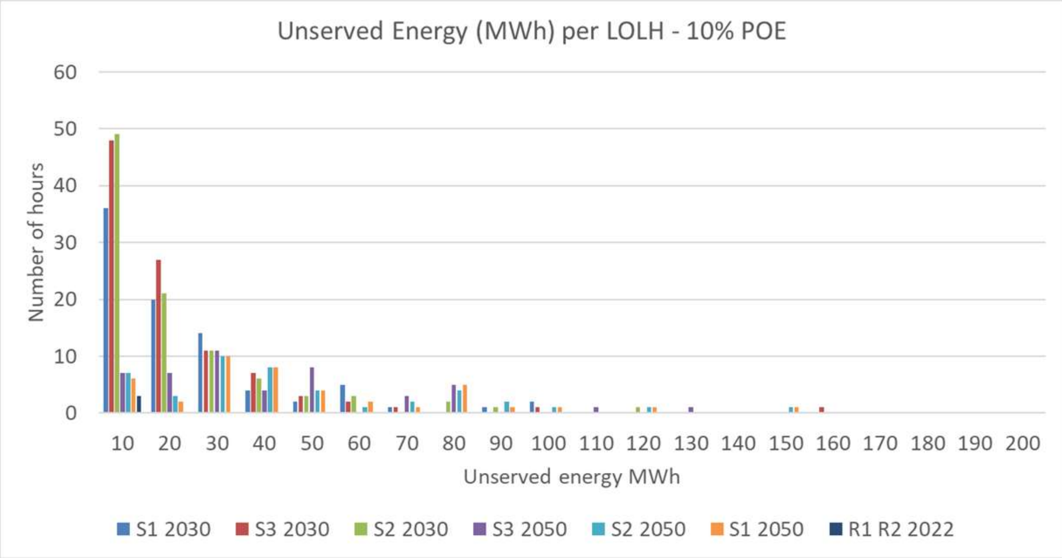
50% POE

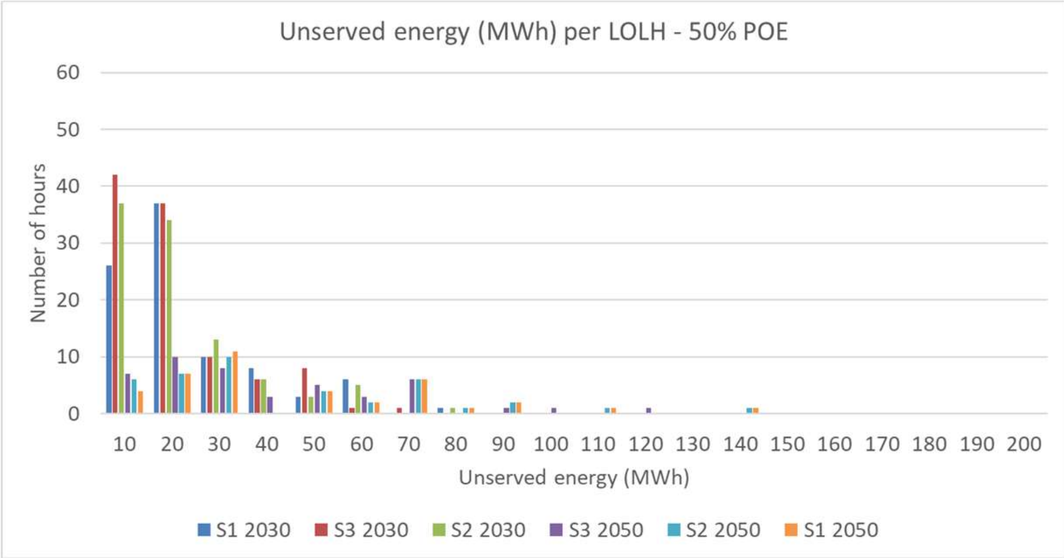
Time	S1 2030	S2 2030	S3 2030	S1 2050	S2 2050	S3 2050
12 AM						
1 AM						
2 AM						
3 AM						
4 AM						
5 AM						
6 AM						
7 AM	15.6	14.0	15.4	103.2	97.9	62.4
8 AM						
9 AM						
10 AM						
11 AM						
12 PM						
1 PM						
2 PM						
3 PM						
4 PM	121.2	105.9	109.6			
5 PM		9.9	24.4	305.3	305.8	232.8
6 PM	43.3	144.3	244.0	491.6	490.2	525.8
7 PM	3.1	38.5	78.2	166.4	170.1	178.3
8 PM		0.5	8.6	270.9	270.7	289.7
9 PM	1455.5	1324.0	1162.7	233.7	223.0	280.0
10 PM	55.0	51.5	34.0			
11 PM						

Low UE — High UE

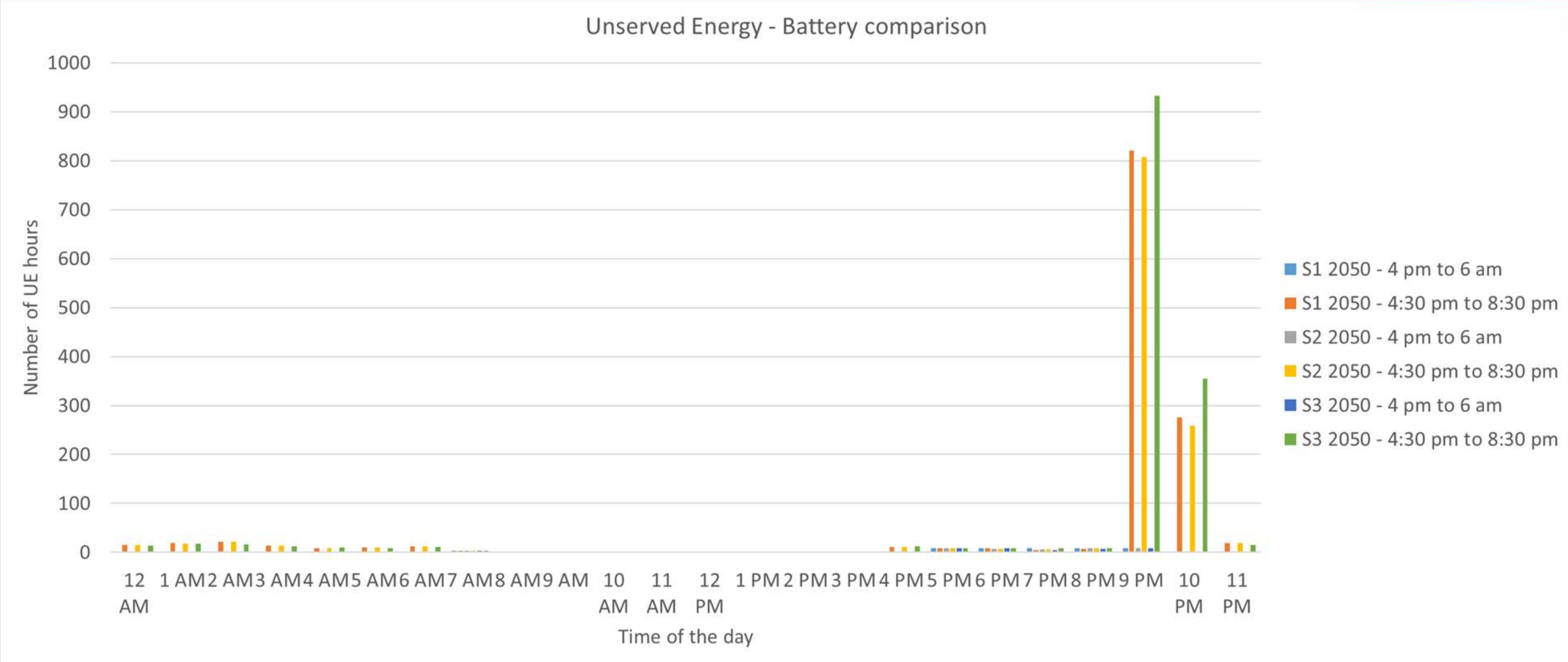
- The UE peaks at **9:00pm** in **2030**. This is because the battery reliability hours are between 4:30pm and 8:30pm and unavailability of battery leads to large UE.
- In **2050**, highest UE is experienced at **6:00pm** when the solar output is the very low and the demand is high.

Modelling Results – Measurements of Unserved Energy (2)



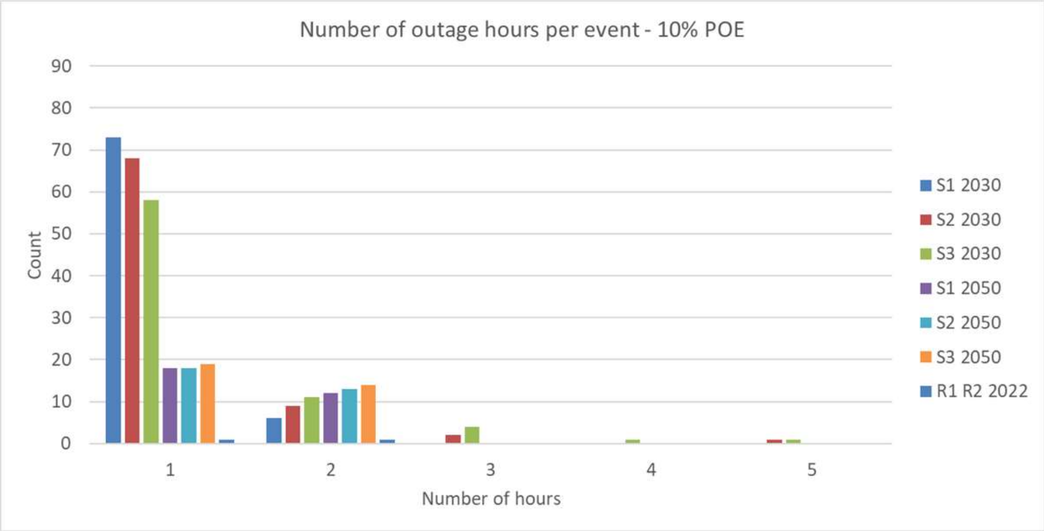


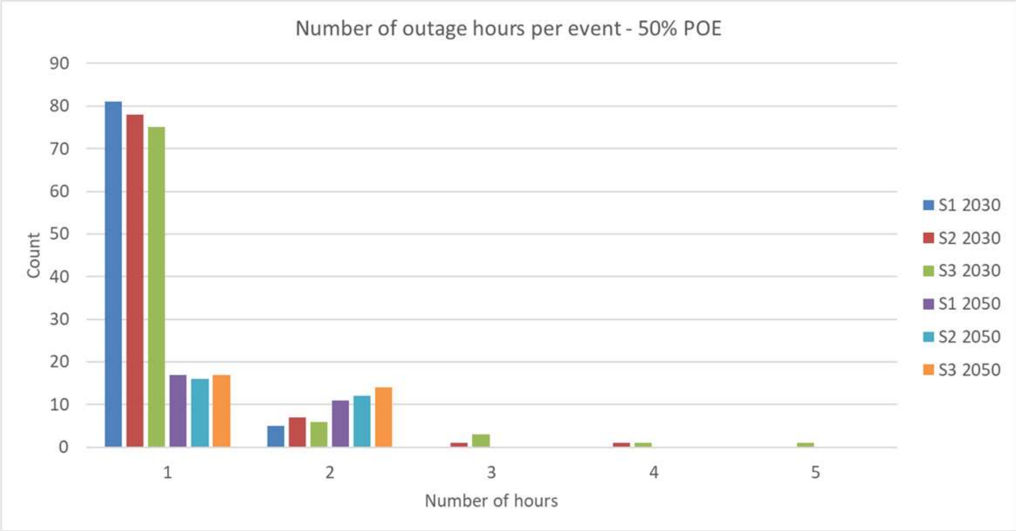
Modelling Results – Timing of Firming Resource – 50% POE



- If storage discharge periods are limited to the current RCM setting (4:30pm to 8:30pm), unserved energy occurs overnight in 2050 scenarios.
- Extending storage availability overnight prevents this.
- This indicates that capacity services are required for a broader range of hours in 2050.

Modelling Results show short, shallow outages

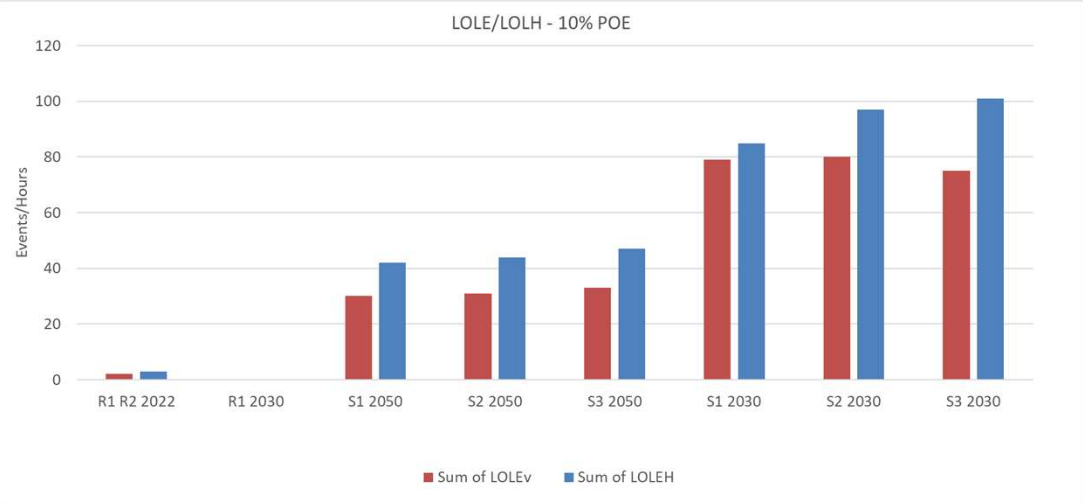


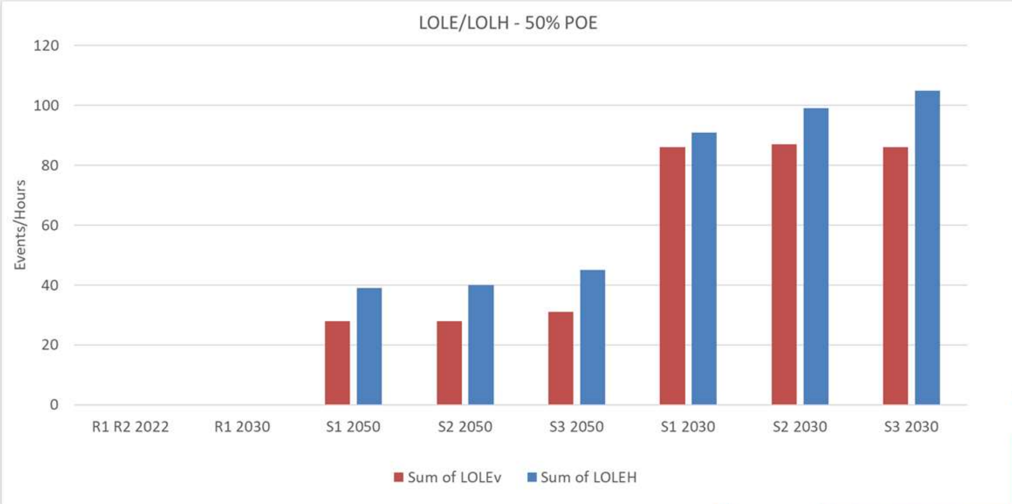


- Most outages are short – one or two hours – with a small number of outages up to 5 hours duration.
- The 50% POE cases have shorter, shallower events while 10% POE cases have slightly longer/deeper events.

Modelling Results – Measurements of Unserved Energy

- Unserved energy at current reliability criteria levels represents a very small number of loss of load hours (LOLH) or events (LOLEv).
- Each LOLH can represent a very wide range of MWh outage quantities.
- UE remains the most nuanced measure of reliability impact.





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Agenda Item 6(c): Update on the Cost Allocation Review Working Group

Market Advisory Committee (**MAC**) Meeting 2022_06_28

1. Purpose

- The Chair of the Cost Allocation Review Working Group (**CARWG**) is to update the MAC on the activities of the CARWG since the last MAC meeting.
- The MAC is requested to provide support for:
  - the proposed priorities for the assessment of the allocation of the Market Fees and ESS costs; and
  - the options proposed to be assessed for the allocation of the Market Fees and ESS costs.

2. Recommendation

That the MAC:

(1) notes the minutes from the CARWG meeting on 9 May 2022 (**Attachment 1**);

(2) notes the update on the CARWG meeting on 7 June 2022 (**Attachment 2**); and

(3) provides support for:

(a) assigning high priority to the assessment of the allocation of the Market Fees;

(b) assessing the following options for allocating Market Fees, in comparison to the current allocation methodology:

- the current NEM practice (see option 2, slide 9);
- a 'Hybrid Gross MW/MWh' option (see option 4, slide 10);

(c) prioritising the assessment of the allocating ESS costs as follows:

- Frequency Regulation as a high priority;
- Contingency Reserve (Raise and Lower), Black Start and Non-co-optimised ESS as a medium priority;
- RoCoF is to be classified further after further consultation with AEMO;
- black start, Non-co-optimised ESS and fast frequency response are a low priority (no further assessment required);

(d) assessing the following options for allocating Frequency Regulation costs, in comparison to the current methodology:

- the current NEM practice (see option 2, slide 12);
- a new causer-pays methodology, potentially based on 'Tolerances' (see option 3, slide 12); and

(e) assessing the following options for allocating Contingency Reserve Lower costs, in comparison to the current allocation methodology:

- a new modified runway method applied to loads (see option 2, slide 14).

3. Background

The CARWG held its first meeting on 9 May 2022. The MAC was provided with an update on the 9 May 2022 CARWG meeting at the MAC meeting on 17 May 2022 and a copy of the CARWG minutes is attached for information (**Attachment 1**).

The CARWG held its second meeting on 7 June 2022 to:

- review the preliminary results and conclusions from the jurisdictional review (step 1(a) from the Scope of Works for the review);
- discuss the priority and options for assessment of the methodologies to allocate Market Fees and ESS costs to align these with the causer-pays and beneficiary-pays principles (step (1(b) from the Scope of Works for the review); and
- provide initial feedback on options to allocate Market Fees and ESS costs.

Attachment 2 provides a summary of the outcomes from the 7 June 2022 CARWG meeting. Attachment 2 will be taken as read at the MAC meeting on 28 June 2022 and the MAC will be asked to provide guidance to the CARWG on the matters listed in section 2 above.

4. Attachments

(1) Cost Allocation Review Working Group – Minutes of Meeting 9 May 2022

(2) WEM Cost Allocation Review – Update to the Market Advisory Committee 28 June 2022

Government of **Western Australia**
Energy Policy WA

Minutes

Meeting Title:	Cost Allocation Review Working Group (**CARWG**)
Date:	9 May 2022
Time:	1:00pm – 2:30pm
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	
Oscar Carlberg	Alinta Energy	
Tom Frood	Bright Energy	
Rebecca White	Collgar Wind Farm	
Noel Schubert	Small-Use Consumer Representative	
Mark McKinnon	Western Power	
Jason Found	Synergy	
Genevieve Teo	Synergy	
Paul Arias	Bluewaters Power	
Edwin Ong	AEMO	
Cameron Parrotte	Woodside	
Grant Draper	Marsden Jacob Associates (**MJA**)	
Andrew Campbell	MJA	
Hana Ramli	MJA	
Stephen Eliot	Energy Policy WA (**EPWA**)	
Shelley Worthington	EPWA	

Apologies	From	Comment
None		

Item	Subject	Action
1	**Welcome and Agenda** The Chair opened the meeting at 1:00pm and invited the attendees to introduce themselves.	

Item	Subject	Action
	The Chair reminded CARWG members of the guiding principles for the Cost Allocation Review (section 2.2 of the Scope of Works) and, in particular, noted that: • the cost allocation methodologies must be cost effective, simple, flexible, sustainable, practical and fair; and • the 'causer pays' principle will be applied where practicable and efficient so that the cost allocation methodologies incentivise Market Participants to minimise overall costs to consumers.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	

3	**Project Scope and Timeline**
	Mr Draper reviewed the project scope (slides 3-5), which is to align the allocation of Market Fees and Essential System Services (**ESS**) costs with the causer pays principle.
	• Ms White sought clarity on the ESS costs that are out of scope because they were recently reviewed by the Energy Transformation Taskforce. The Chair indicated that:
	  ○ the Scope of Work highlights what the Taskforce had previously considered, which will not be reconsidered, including the full runway method for allocating Contingency Raise services and Rate of Change of Frequency (**RoCoF**) Control service;
	  ○ the Taskforce did not look at allocating costs for Regulation Raise and Lower, so this is in scope; and
	  ○ for the Market Fees, the review will look at the costs recovered under AEMO's allowable revenue, not at costs recovered elsewhere in the market, such as existing application fees.
	• Ms White noted that the Taskforce substantially looked into allocation of costs for Regulation services but that there were implementation problems related to the lack of five-minute metering until 2025.
	  ○ The Chair indicated that the CARWG should consider data requirements after determining the best cost-reflective and efficient allocation methodologies, and implementation may need to be delayed if five-minute settlement is required.
	  ○ Mr Draper indicated that the team would contact Ms White to discuss the Taskforce's work on allocation of Regulation service costs.
	Mr Draper reviewed the timeline for the project (slides 6-7).	

4	**Stakeholder Engagement Plan** Mr Draper reviewed the stakeholder engagement plan (slides 7-9) and noted that EPWA has emphasised stakeholder engagement and that the WEM Rules require the Coordinator to consult with the MAC before	

Item	Subject	Action
	developing a Rule Change Proposal. Stakeholder engagement will be primarily through CARWG and MAC. Mr Draper provided a revised schedule for CARWG meetings. No CARWG members indicated concerns with the revised schedule.	

5	**Approach to Policy Assessment**
	Mr Draper provided an overview of the approach to policy assessment (slides 10-11):
	• Mr Draper noted that the causer pays concept has always been implicit in the Wholesale Electricity Market (**WEM**) but there has never been an explicit framework for how it should be applied.
	• The only explicit cost allocation framework that MJA has identified was developed by the Independent Pricing and Regulatory Tribunal (**IPART**) (NSW) around allocation of local government water costs. Mr Draper reviewed this framework (slide 11).
	• Mr Draper noted that the literature indicates that the causers and beneficiaries are often the same party if there are no externalities, but they can be also quite different. The allocation methodology can be considered once the causers and beneficiaries are identified, at which point consideration needs to be given to economic efficiency, incentives and equity.
	• Mr Carlberg asked whether cross-subsidies should be considered in formulating the allocation framework.
	    o The Chair noted that there are clear cross-subsidies where flat fees and charges are used – such as for Regulation services or Market Fees, and to an extent cross-subsidies are also embedded elsewhere, such as in the allocation of RoCoF Control costs.
	    o Mr Carlberg, responded that the biggest cross-subsidies are in the Market Fees and Regulation services, and in relation to Distributed Energy Resources (**DER**), because DER can get around Market Fees. Mr Carlberg clarified that he wants to focus first on the biggest cross-subsidies.
	    o The Chair asked CARWG members to provide examples of where the Market Fee or ESS cost allocations are not sending the appropriate signals and where the causer pays principle should apply.
	    o The Chair indicated that the CARWG should first focus on Market Fees and Regulation services but can shift this focus if it determines that there are bigger cross-subsidy issues.
	    o Ms White agreed with having an eye on cross-subsidies, particularly in relation to transmission connected participants subsiding DER, noting there is an intent to have DER pay some costs under the causer pays principles, via aggregators participating in the WEM. The Chair indicated that this issue will be considered.	

Item	Subject	Action
	○ Mr Schubert noted that the Cost Allocation Review is about improving the allocation of costs to causers or beneficiaries, but there might be other parties that could help reduce costs if they are adequately incentivised to do so. Mr Schubert suggested that there is an opportunity to introduce incentives to third party 'enablers' who could reduce overall costs. ○ The Chair agreed that, when we consider passing costs through to a causer, it is important to account for any benefits that the causer creates in reducing costs elsewhere. ○ Mr Froud noted that all cost will be paid by either electricity users or taxpayers, and one of the ongoing challenges is managing the cross-subsidy between users and taxpayers. The Chair reminded the CARWG members that they can only recommend changes to the WEM Rules. ○ Mr Parrotte noted that the CARWG should not get into the space of defining ESS. Mr Parrotte also noted that, in designing an approach to cost allocation, it is important to not put incentives in place to avoid costs which in turn may result in worse overall market outcomes. ○ Mr Draper provided an example – allocating fees and charges based on grid (or net) energy rather than gross energy provides an incentive for parties to install behind the meter technology. • Mr Draper noted that, based on the IPART framework, if we cannot easily charge the causer or beneficiary, then we would spread costs across all market participants and customers.	
	ACTION: CARWG members are to advise EPWA by email of any examples where the Market Fees or ESS cost allocations are not sending the appropriate signals and where the causer pays principle should apply.	**CARWG members (before the next CARWG meeting)**
6	**Early Findings from the Policy Assessment Analysis** Mr Draper provided an indication of the relative significance of Market Fees and ESS costs (slides 12-13) – Market Fees represent only about 0.5% of total costs and ESS costs about 6%. • The Chair pointed out that the current thinking is that ESS costs will increase as a percentage of total costs with increased penetration of DER and renewable electricity generation, more generally. • Mr Draper and Mr Campbell agreed but suggested that increased storage penetration may dampen the increase in Regulation, Contingency Reserve Raise and Contingency Reserve Lower. • Mr Frood asked whether synchronous condensers could also provide ESS services. The Chair noted that synchronous condensers are compensated to an extent through network charges and Mr Parrotte noted that they can also receive compensation through RoCoF Control services.	

Item	Subject	Action
	Mr Draper provided an indication of the drivers for WEM services costs (e.g. AEMO's costs) (slide 14). • Mr Arias commented that business-as-usual (**BAU**) operations vs. large scale reforms potentially have different beneficiaries and asked about separating the allocation of these two types of costs. • Mr Draper indicated that AEMO tracks these costs and that it is in scope to consider what is BAU vs. programs to improve the overall efficiency of the market. • In response to a question from the Chair, Mr Arias indicated that his question does not relate to ESS costs, only whether it is appropriate to target reform costs via Market Fees when the reforms have distinct beneficiaries. • The Chair noted that the intent is to identify the causers and beneficiaries of costs and it is recognised that they may not be the same people. For example, policies that drive DER integration may benefit more than just DER participants, so we need to identify all of the causers and beneficiaries. • Mr Parrotte noted that AEMO did a lot of work in its latest revenue submission on the costs for the individual reform tasks and agreed with Mr Arias that there is a difference between BAU and the reforms, and between the causers and beneficiaries. Mr Draper provided an indication of the drivers for ESS costs (slides 15-16) and noted that: • Regulation services are caused by unexpected deviations between actual and forecasted supply and demand so, based on the causer pays principle, these costs could be allocated to parties with the largest deviations. However, this may not be implementable, so it may be necessary to allocate these costs to everyone. • Contingency Raise services deal with the loss of a generator or storage facility, and these costs are typically allocated to generators (noting that one of the potential gaps that needs to be considered is whether smaller non-scheduled generators contribute to the need for these services but do not directly bear these costs); • Contingency Lower services are typically about a drop in consumption, so these costs are typically allocated to loads; and • RoCoF Control services are about inertia, which can be impacted by generators and network facilities, as well as by users in terms of ride through capability, so all participants can impact RoCoF Control services. The Chair noted that RoCoF Control costs are currently split equally between generators, users and the network operator, and that this arrangement is not cost reflective, but it is a new arrangement that was implemented by the Taskforce, so it is not a priority. Mr Parrotte also noted that we do not yet know the value of the RoCoF Control service, so we do not yet know if it is a priority.	

Item	Subject	Action
	Mr Draper outlined the preliminary work to identify the causers and beneficiaries of market services and ESS (sides 17-24). • Mr Draper pointed out that all Market Participants are both causers and beneficiaries of market services and ESS to some extent, so there is some justification to allocate Market Fees and various ESS costs to each of them. However, there are other parties that are also causers or beneficiaries that are not formal Market Participants and cannot be attributed charges, such as embedded storage or generation owners, microgrid owners, final customers, Distribution Network Service Providers, Transmission Network Service Providers and the State Government. • Mr Draper asked all CARWG members to review the table in slides 18-21 and provide comments on whether anything is incorrect or missing. The Chair reminded the CARWG members to keep comments to issues that can be practically addressed under the WEM Rules. • Ms White considered the table was useful but suggested that the identification of causes and beneficiaries may need to be more granular. Ms White also suggested that, while Government will not inject funds into the market, it would still be useful to capture where Government reforms drive market costs and benefits, particularly in the DER space. Mr Schubert agreed with Ms White. • Mr Frood pointed out that the focus should not only be on the costs of Government policy but also on the benefits from these policies. • Mr Draper noted that IPART’s hierarchy would first allocate costs to causers, then to beneficiaries and then, as a last resort, to taxpayers (which would be across all Market Participants). • The Chair noted that the CARWG is to identify the parties that can impact market services or ESS costs and allocate costs to those parties, where this can be done under the WEM Rules. The CARWG is not to try to shift costs to Government. • Mr Froud agreed that the CARWG’s scope should be limited to issues that can be addressed under the WEM Rules and noted that it would be out of scope to recommend changes to electricity retail tariffs or for government to commit to paying costs. Mr Draper advised that MJA is reviewing cost allocation methods in other jurisdictions and provided some early feedback from its review on two issues: • If grid demand is reducing due to growth in behind the meter generation, should charges be levied based on net or gross demand? ○ Mr Draper indicated that Ofgem (UK) uses a bundled service for Balancing Services Use of System (BSUoS) charges, and that they are moving to a definition of gross demand to capture behind the meter technology.	

Item	Subject	Action

	• With declining operational consumption, should Market Fees be charged on a different basis?
	  ○ The National Energy Market (**NEM**) is:
	    ▪ moving away from only a $/MWh charge to both $/MWh and $/NMI charges;
	    ▪ changing the allocation of fees (e.g. Wholesale Participants to be allocated 55.9%, Market Customers to be allocated 26.6% and TNSPs to be allocated 17.5% of AEMO direct costs); and
	    ▪ looking to allocate costs for transformational projects to specific parties (including market customers, DER resources and/or existing market participants).	

	ACTION: CARWG members are to review the tables in slides 18-21 and provide comments on whether anything is incorrect or missing.	**CARWG members (prior to the next CARWG meeting)**
7	**Next Steps** The Chair thanked CARWG members for their participation and encouraged members to email any information to EPWA regarding cost allocation in other jurisdictions (e.g. in the NEM). The Chair noted the CARWG meetings will continue as per the agreed schedule.	
8	**General Business** No general business was discussed. The next CARWG meeting is scheduled for 7 June 2022.	

The meeting closed at 2:30pm.

Government of **Western Australia**
Energy Policy WA

WEM Cost Allocation Review

Update to the Market Advisory Committee

28 June 2022

Presenter: Grant Draper, Marsden Jacob Associates

Working together for a
brighter energy future.

Agenda

Purpose of the Policy Assessment

Assessment of Priorities and Options

- **Incorporates CARWG feedback**
- **Seeking MAC guidance**

Appendix One* – Jurisdictional Review, Step 1(a)

Appendix Two* – WEM Alignment with the Causer-Pays / Beneficiary-Pays Principle, Step 1(b)

* **Provides background material only and will not be discussed at this meeting**

Timeline

Steps/Tasks	Duration/Timing
Step 1 – Policy Assessments	
(a) Literature review of the methodologies to allocate Market Fees and ESS costs in other jurisdictions.	Mid-April to Mid-May 2022
(b) In consultation with the MAC Working Group, assess whether, and to what extent, the current allocation method for the Market Fees and for the costs for each of the ESS are aligned with the causer-pays principle and, if not, whether they should be.	Mid-May to Mid-June 2022
Step 2 – Practicability Assessments	
In consultation with the MAC Working Group, for the fees and costs that are not aligned, or not fully aligned, with causer-pays principle: • Identify the options that can be practically and efficiently applied in the WEM to allocate the Market Fees and each ESS cost; • Assess each option against the guiding principles; • Model the impact of each of the options on Market Participants; and • Recommend a preferred option for the allocation of the Market Fees and each ESS cost.	July-August 2022
Step 3 – Methodology Development	
Develop the details of the cost allocation methodologies in consultation with the MAC Working Group	September-October 2022
Develop and publish a consultation paper on the design for the allocation methodologies and seek stakeholder comments.	November-January 2023
Develop publish an information paper on the detailed design for the allocation methodologies.	March 2023
Step 4 – Formal Rule Change	
Develop one or more Rule Change Proposals for consideration by MAC, and approval by the Coordinator and Minister.	April 2023

Assessment to Date (Step 1)

a) Literature Review of the methodologies to allocate Market Fees and ESS costs in other jurisdictions.

b) In consultation with the CARWG, assess whether, and to what extent, the current allocation method for the Market Fees and for the costs for each of the ESS are aligned with the causer-pays principle and, if not, whether they should be.*

Purpose of this MAC agenda item is to seek MAC support for the Working Group initial assessment of cost allocation methods for Market Services and ESS and priorities for review in the next stage of assessment of cost allocation methodologies.

* Have extended this to also consider the beneficiary-pays principle.

Assessment of Options Against the Review Criteria

Guiding Principles / Criteria

1. Meet the Wholesale Market Objectives (i.e., economic efficiency, safe and reliable, technology neutral, encourage competition, minimise long term costs, and encourage energy efficiency);
2. Be cost-effective, simple, flexible, sustainable, practical, and fair;
3. Provide effective incentives to Market Participants to operate efficiently to minimise the overall cost to consumers; and
4. Use the causer-pays principle, where practicable and efficient.
5. Use the beneficiary-pays principle where appropriate (extended to scope)

Assessment of Priority – Summary

	Causers of Service	Is proposed cost allocation practice aligned with Guiding Principles?	Consequence of mis-alignment	Assessment Priority	Rationale	Next Steps
Market Services	Market Participants (Generators / Retailers) Network Operators DER / Final Customers	Only partially aligned with Causer Pays method	Impact on market outcomes is low (economic efficiency and cost burden)	High	Has not been reviewed previously	Development and assessment of two alternative options to current practice
Frequency Regulation	Scheduled Generators Semi-Scheduled Generators Loads (inc. DER)	Not aligned	Not driving reduction in level and cost of providing regulation services	High	Has not been reviewed previously	Development and assessment of two alternative options to current practice
Contingency Reserve Raise	Scheduled Generators Semi-Scheduled Generators	Aligned with Causer Pays method	Aligned	Medium	Runway method was reviewed by ETT	Refinement of proposed method to address equity issues
Contingency Reserve Lower	Small and Large Loads Energy Storage (recharge)	Only partially aligned with Causer Pays method	Not providing incentives for large loads / energy storage to minimise load reduction	Medium	Emerging issue with storage systems entering the SWIS	Modified runway method to be developed. No precedent for this (outcome uncertain)

Assessment of Priority – Summary

Service	Causers of Service	Is proposed cost allocation practice aligned with Guiding Principles?	Consequence of mis-alignment	Assessment Priority	Rationale	Next Steps
RoCoF	Scheduled Generators Semi-Scheduled Generators Loads (inc. DER)	Partial alignment with Causer and Beneficiary Pays Principles	Unknown	TBD	Has been reviewed by ETT	Development of new method to split costs between causers / beneficiaries
Black Start	No specific causer	Aligned	Aligned	Low	No major benefit of further assessment	No further assessment required
Non-co-optimised ESS	Network Operator	Aligned	Aligned	Low	No major benefit of further assessment	No further assessment required
Fast Frequency Response (Temporary Service in WEM)	Scheduled Generators Semi-Scheduled Generators Loads (inc. DER)	NA	NA	Low	Review when FFR becomes permanent service in WEM	No further assessment required

Assessment of Options against the Review Criteria

Service	Priority	Cost Recovery Option	Advantage / Disadvantage
Market (Fees)	High	**1. Current WEM practice:** • Based on sent out generation and/or load for all their Registered Facilities and Non-Dispatchable Loads for all Trading Intervals for the day	• Simple and easy to apply. • Has already been incorporated into existing Contracts • Partially excludes other causers, such as DER, and fully excludes Network Operators, both of which can be regarded as causers of AEMO costs (i.e., DER programs, integrating distribution connected storage, constrained network access). • Almost totally excludes generators that rarely operate (e.g., diesel generators).
		2. Current NEM practice: • Splits between generators, Market Customers and TNSPs (based on directly attributable costs, unattributable allocated to Market Customer) • For Wholesale Market Participants: ○ 50% charged on capacity (MW) ○ 50% on Grid MWh (or FCAS enablement for MASPs/DRSPs) • For Market Customer, fees allocated on basis of both Grid MWh and NMIs	• Consistent with causer-pays in attempting to attribute costs based on Market Participant interactions with AEMO. • Capacity charges on Market Participants ensures generators that rarely operate contribute to AEMO fees. • For Market Customer allocations, having split between Grid MWh and NMIs addresses competition issues (i.e., reduces costs for smaller retailers). • Multi-site customers are penalized by charges based on the number of NMIs. • Doesn’t capture customers in embedded networks unless passed on by embedded network operator. • Still includes variable charges (Grid MWh) even though AEMO costs do not vary with usage. • Using Grid MWh for cost allocation only partially allocates costs to DER. • May require changes to PPAs to incorporate the new fee structure.

Assessment of Options against the Review Criteria

Service	Priority	Cost Recovery Option	Advantage / Disadvantage
Market (Fees)	High	**3. Gross MWh only (GB – National Grid):** • Recover all Market Fees from loads on Gross Consumption basis (includes DER generation).	• Fully captures DER. • Accepts that market fees are focused only on cost recovery, not market efficiency, and that it is inefficient (higher transaction costs) to pass costs to wholesale market participants and network operators, who then pass on costs to retailers, and then final customers. • Financial burden solely on retailers and aggregators. • May need to change PPAs to incorporate new fee structure. • **Do not take forward:** Western Power has confirmed that smart meters deployed in the SWIS cannot measure gross PV generation
		4. Hybrid Gross MW Option: • Splits between generators, Market Customers and TNSPs (based on directly attributable costs, unattributable allocated to Market Customer) • For Wholesale Market Participants: ○ 50% charged on capacity (MW) ○ 50% on Grid MWh • For Market Customer: ○ 50% based on gross capacity (i.e., sum of DER installed MW and Grid Demand MW) ○ 50% based on connection points (or NMIs).	• Consistent with causer-pays in attempting to attribute costs based on Market Participant interactions with AEMO. • Capacity charges on Market Participants ensures generators that rarely operate contribute to AEMO fees. • For Market Customers, capacity charges and connection charges ensures that DER contributes to cost recovery. • Can utilise DER register to determine billing determinant. • Complexity and cost to implement. • May need to change wholesale contracts to incorporate new fee structure.

MAC Guidance on Market Fees Cost Allocation

Based on CARWG discussions, the MAC is requested to support the following:

- High prioritisation for development of new cost allocation methods for Market Fees.
- Of the three alternative options outlined in previous slides, only the following two (2) options will be developed further and compared to the current cost allocation in the WEM:
  - Current NEM Practice
  - Hybrid Gross MW Option

Assessment of Options against the Review Criteria

Service	Priority	Cost Recovery Option	Advantage / Disadvantage
Frequency Regulation	High	1. **Current WEM practice:** • Semi-scheduled, non-scheduled and non-dispatchable loads based on Grid MWh	• Frequency regulation costs are not driven by Grid MWh consumed or generated. • Other causers are excluded, such as scheduled generators and DER.
		2. **Current NEM practice:** • Current causer-pays methodology – calculations are based on actual performance (ex-post)	• Provides price signal to users to provide more accurate forecasts and better control of generation / loads. • Complexity and cost to implement.
		3. **New causer pays methodology (potentially based on Tolerances)** (to be developed in conjunction with AEMO) • Causers would be those setting the requirement ex-ante based on their projected tolerance • Payment would be as a proportion of total tolerances	• Provides dynamic price signals to causers of the cost of this service • Complexity and costs to implement.

Assessment of Options against the Review Criteria

Service	Priority	Cost Recovery Option	Advantage / Disadvantage
Contingency Reserve Raise	Medium	**Proposed WEM practice:** • Runway method for allocating costs to generators	• More of the costs allocated to the largest generator operating in a trading interval. • This is consistent with causer pays methodology. • Must address some equity issues (number of connections per customer) that have arisen with application of this method.

Assessment of Options against the Review Criteria

Service	Priority	Cost Recovery Option	Advantage / Disadvantage
Contingency Reserve Lower	Medium	**1. Current Method:** • Allocated to loads based on Grid MWh	• Only partial allocation of costs to large commercial and industrial loads who are the major causer of the requirement of this service.
		2. New Method: • Modified runway method applied to loads	• Most costs allocated to largest loads (including energy storage) who are mainly responsible for the provision of this service. • Complexity in developing a new method and uncertainty as to whether loads would respond to price signals provided.
RoCoF	Difficult to prioritise given we do not know service requirement and costs (AEMO to provide some estimates)	**Current Method:** • Loads, network operator and generators (1/3 cost shares)	• Costs split evenly between beneficiaries, which provides incentives for participants to improve 'ride-through' capability of equipment. • Only arbitrary allocation of cost shares.

Assessment of Options against the Review Criteria

Service	Priority	Cost Recovery Option	Advantage / Disadvantage
Black Start	Low	• Allocate costs to Market Customers on basis of combination of $ per MWh (Grid) or $ per NMI (connection), and even installed DER capacity (consistent with potential Market Fees allocation approach).	• No identifiable causers, so simply allocate costs to customers (through retailers and aggregators). This is consistent with the beneficiary-pays principle.
Non-co-optimised ESS provided by Western Power and AEMO	Low	• If Western Power procures the NCESS, recover from network tariffs. • If AEMO procures the NCESS, recover on basis of Grid MWh via retailers.	• Consistent with the beneficiary-pays principles.
Fast Frequency Service (temporary service)	Low	• In the future, allocate costs on same basis as for contingency reserve services.	• The causer of the requirement for this service is the same as the requirement for contingency reserve services. Costs should be allocated to the "causers" of variations in frequency on the same basis.

MAC Guidance on Essential System Services Cost Allocation

Based on CARWG discussions, the MAC is requested to support the following:

- Prioritisation of ESS charges that will be developed and assessed further:
  - Frequency Regulation is the only High priority
  - Contingency Reserve (Raise and Lower) are Medium priorities.
  - RoCoF will be classified after further consultation with AEMO on the potential burden of charges on beneficiaries.
  - Black Start, Non-co-optimised ESS and FFR are all classified as Low priority – no further assessment required.

MAC Guidance on Essential System Services Cost Allocation

Based on the Working Group discussions, MAC is requested to support the following::

- Of the options outlined for Frequency Regulation, both will be developed further and assessed:
  - Current NEM Practice (Causer Pays Methodology)
  - New causer pays methodology potentially based on Tolerances
- The alternative solution for Contingency Reserve Lower will be developed and further assessed:
  - New Method based on modified runway method for loads

Appendix One: Jurisdictional Review 1(a)

Jurisdictions in Scope

Reviewed the following jurisdictions:

- Wholesale Energy Market (WEM), Western Australia
- National Energy Market (NEM), Eastern Australia
- National Electricity Market of Singapore (NEMS)
- California Independent System Operator (CAISO), United States
- Electricity Reliability Council of Texas (ERCOT), United States
- Pennsylvania, New Jersey, and Maryland (PJM) Interconnection, United States
- Integrated Single Electricity Market (I-SEM), Ireland
- Great Britain (National Grid)

Summary of jurisdictional review provided in **Appendix 1**

Service Equivalents Across Jurisdictions

WEM	NEM	NEMS	CAISO	ERCOT	PJM	I-SEM	GB (National Grid)
Market and System Services (Fee)							
AEMO Market Services	NEM Service	EMC Service	Grid Management	System Administration	Control Area Administration Market Support Service	Transmission System Operator (TSO)	Electricity System Operator (ESO) Internal
System Operation							
Economic Regulation	There are service equivalents but costs not recovered by Market Fees						
Market Rule Changes							
Frequency Control Essential System Services (typically co-optimised with Energy Market)							
Frequency Regulation Raise	FCAS Regulation Raise	Regulation	Regulation Up	Regulation Up	Regulation	Synchronous Inertial Response Fast Frequency Response (FFR)	Response
Frequency Regulation Lower	FCAS Regulation Lower		Regulation Down	Regulation Down			
Contingency Reserve Raise	Contingency FCAS Raise	Reserve	Spinning Reserve Non-Spinning Reserve	Responsive Reserve Non-Spinning Reserve	Primary Reserve: (a) Synchronised (b) Non-Synchronised Day Ahead Scheduling Reserve	Primary Operating Reserve Secondary Operating Reserve Tertiary Operating Reserve	Fast Reserve Operating Reserve Short Term Operating Reserve
Contingency Reserve Lower	Contingency FCAS Lower						

Service Equivalents Across Jurisdictions (continued)

WEM	NEM	NEMS	CAISO	ERCOT	PJM	I-SEM	GB (National Grid)
RoCoF	There are service equivalents but not provided as unbundled service with itemised charge						Bundled into BSUoS
Other Essential System Services (not co-optimised with energy market)							
System Restart Services	System Restart Ancillary Service	Black-Start capability	Black Start Service	Black Start Services	Black Start Service	Black Start	Black Start
Non-Co-optimised ESS	Network Support and Control Ancillary Services	Reactive Support and Voltage Control Service	Voltage Support	Voltage Support	Reactive Service and Voltage Control	Steady State Reactive Power	Reactive Constraint (Voltage)
Non-Co-optimised ESS Fast Frequency Response (Transitional)	Co-optimised Ancillary Service Fast Frequency Response				Incorporated into existing regulation service category		Fast Frequency Response Services: Dynamic Containment Dynamic Moderation Dynamic Regulation

Causer Pays Adherence – WEM

Service	Cost Recovery Method	Causer Pays Adherence
Market and System Operator	Charge on Grid MWh for Market Participants	Medium • Partially excludes other causers such as DER and fully excludes Network Operators.
Essential System Services (Ancillary Services)		
Frequency Regulation	Loads and intermittent generators (Grid MWh).	Low • Frequency regulation costs are not driven by Grid MWh consumed or generated. • Other causers are excluded such as scheduled generators and DER.
Contingency Regulation	Modified runway method to allocate costs to generators.	High • More of the costs allocated to the largest generator operating in a trading interval. • This is consistent with causer pays methodology.
Contingency Reserve Lower	Allocated to loads based on Grid MWh.	Medium • Costs allocated across all loads which includes large commercial and industrial loads who are the major causer of the requirement of this service.
Inertia	Loads, network operator and generators.	Medium • Costs split evenly between beneficiaries, which provides incentives for participants to improve ‘ride-through’ capability of equipment.

Causer Pays Adherence – NEM

Service	Cost Recovery Method	Causer Pays Adherence
Market Operator	Mixture of fixed and variable charges on participants (includes aggregators) and network operators.	Medium • Still includes variable charges even though these costs do not vary with usage or demand. • However, competition considerations could be important as moving from a $/MWh charge to a $/user charge will have relatively larger impacts on smaller retailers/aggregators and could be seen as a barrier to entry.
Ancillary Services		
Frequency Regulation	Causer pays methodology to determine contribution factors for loads and generators.	High
Contingency Reserve	Grid MWh for loads and generators	Medium

Causer Pays Adherence - Other Jurisdictions

Jurisdiction	Service	Cost Recovery Method	Causer Pays Adherence
NEMS (Singapore)			
	Market Operator	Fixed and variable fees on market participants.	High
	Ancillary Services		
	Regulation	Loads and first 10 MW of each generation facility being dispatched.	Medium
	Reserve	Variant of runway model to calculate costs for each dispatchable facility.	High • Most costs allocated to largest generator in operation.
CAISO (California)			
	Market Operator	Unbundled grid management charge on service users ($ per MWh).	Low
	Ancillary Services	Unit charge on load serving entities.	Low
ERCOT			
	Market Operator	United charge on Qualified Scheduling Entities based on load.	Low
	Ancillary Services		
	Regulation	Unit charge on load serving entities.	Low
	Reserve	Unit charge on load serving entities.	Low

Causer Pays Adherence - Other Jurisdictions (continued)

Jurisdiction	Service	Cost Recovery Method	Causer Pays Adherence
PJM (Pennsylvania, New Jersey and Maryland)			
	Market Operator	Unit charges on transmission users.	Medium
	Ancillary Services		
	Regulation	Unit charge on Load serving entities.	Low
	Primary Reserve	Unit charge on Load serving entities.	Low
I-SEM (Ireland)			
	Market Operator	Part of TUoS tariff (unbundled) on transmission users (generators and loads).	Medium
	Ancillary Services		
	System Services	As above.	Medium
National Grid (Great Britain)			
	Market Operator	Part of BSUoS Charge	Low • Uses beneficiary pays principle. • Allocated to customer's gross demand.
	Ancillary Services	Part of BSUoS Charge	Low • Uses beneficiary pays principle. • Allocated to customer's gross demand.

Conclusions from Jurisdictional Review

- **Market Fees –** the NEM has made significant inroads to achieving causer-pays (included more ‘causers’ of costs, such as network users and aggregators). However, the NEM still has a high dependence on Grid MWh charging, which is not a cost driver for AEMO fees.

  AEMO’s approach falls short of Great Britain’s approach to charge customers based on gross demand, which ensures that DER contributes to cost recovery.

  Ofgem’s approach accepts that pricing of market services is about cost recovery and not sending efficient price signals to change behavior (i.e., to encourage transmission users to use less market services). On this basis, Ofgem conclude there are not good efficiency arguments for levying charges on Market Participants. Charges should simply be levied on ultimate beneficiaries of the service (i.e., final customers) or Gross MWh to reduce complexity and remove other distortions in the market.

- **Regulation Services –** the NEM uses a causer-pays methodology to determine contribution factors for allocating costs. This provides incentives for participants to reduce variability in generation and consumption.

Conclusions from Jurisdictional Review (continued)

- **Reserve Raise –** Singapore and the WEM use the runway methodology to allocate costs to generators, which is consistent with causer-pays approaches.
- **Reserve Down –** the WEM allocates costs to loads given that they are likely to be causer of the requirement for this cost (loss of load). However, the major causer of the requirements for this service are large industrial and commercial loads (i.e., loss of a large load which causes system frequency to rise rapidly), who under a causer pays methodology, would pay a higher proportion of costs compared to smaller users. In the future, loss of battery recharging could be a significant requirement for this service.
- **Inertia –** the WEM has a formal unbundled RoCoF service which allocates costs to generators, loads and network operators (1/3 cost attribution for each customer class) which is consistent with the beneficiary pays principle.
- **Fast Frequency Response (Raise and Lower) –** NEM will introduce this service in 2023. Costs to be allocated in same way as other contingency reserve services.

Appendix Two: WEM Alignment with the Causer-Pays Principle

Market Services

Observation 1

Allocating costs to Market Customers (who represent final customers) based on connection costs is consistent with the Causer Pays Principle.

- Splitting the charge between Gross MWh and connection charges would help address equity concerns about the burden of fixed connection charges on smaller users.
- Can use Grid MWh data if Gross MWh data is not readily available.
    - Even though this provides added incentives for DER and energy efficiency (i.e., reduce Grid MWh further), these efficiency losses are expected to be low given the level of Market Fees relative to other value chain costs (e.g., wholesale, network, retail charges and margin etc.).

Market Services

Observation 2

AEMO market and system fees are set to recover total budgeted costs of services provided. It is not based on efficient pricing principles of incremental costs of supply (or marginal costs of supply) required to send price signals to Market Participants to consider reducing the use of AEMO services.

- Levying market fees is unlikely to deter most market participants from continuing to require use of services provided by AEMO (could for some small users).
- In fact, we probably need to increase the use of AEMO services, since greater collaboration between AEMO, network operators, generators and aggregators is required as part of the market reforms that are need to ensure that we have a secure and reliable power system and continued decarbonisation of the system.
- Market Fees are a cost recovery mechanism, with market efficiency not being its primary purpose.
- It is simpler and more equitable to recover all Market Fees from loads (via Market Customers and Aggregators).
- Otherwise, AEMO fees allocated to generators then must be passed through to off takers (e.g., retailers) via wholesale contracts and then passed through to final customers via retail electricity bills. In the case of transmission companies, AEMO fees allocated to them then must be included in network access arrangements and then passed onto network users. This “double handling” of AEMO fees is unnecessary from an efficiency perspective.

Regulation Service

Observation 3

As demonstrated with the causer-pays methodology in the NEM, it is feasible to measure the contribution of causers' frequency deviations and set charges to provide incentives for causers to minimise these frequency deviations in the WEM.

- Charging participants based on Grid MWh (load or generation) is not an appropriate billing determinate and could provide incorrect price signals.
- Increasing DER may reduce a retailer's load.
  - This would reduce the allocation of frequency regulation costs under a unit charging regime, when frequency deviations from that retailer are instead likely to increase because of increased DER penetration in its customer base.

Contingency Reserve Raise

Observation 4

The proposed runway method to allocate Contingency Reserve Raise costs to causers has the potential to increase the efficiency of the WEM if generator dispatch outcomes (e.g., dispatching smaller units) reduce overall wholesale costs (i.e., sum of contingency reserve and energy costs).

- Proposed method does not address the “trip” of a behind-the-meter generator that uses reserves to address the reduction in generation and how this cost should be recovered.

Contingency Reserve Lower

Observation 5

The requirement for the Contingency Reserve Lower service is a function of the size of the potential load that may be lost.

- This is analogous to the way that the largest generator is the causer of the service requirement for the Contingency Reserve Raise
- A runway method could be applied to allocate to allocate Contingency Reserve Lower costs to the largest loads operating in a trading interval.
  - In line with a causer pays approach and the methodology used for the Contingency Reserve Raise.
- This could provide incentives for large loads to utilise energy storage (recharge when load lost) to minimize the requirement for this service.
- The requirement for this service could increase due to increased energy storage in the WEM (recharging).
- Consideration of how network outages (which results in loss of numerous loads) should also be allocated costs would be considered under a causer pays approach. Alternatively, incentives for minimizing network outages can be provided under Network Access arrangements.

RoCoF (Inertia)

Observation 6

Generators, network facilities and large-customers will benefit from improved ride-through capability and should be incentivised to install equipment with better ride-through capability via RoCoF charges.

- Even though these participants are not the causers of lower inertia, they can be incentivised to invest in equipment that can cope with sudden variations in system frequency (beneficiary pays approach).
- Cost attribution levels should be determined based on the benefit that each party receives from improving ride-through capability equipment.

Black Start Services

Observation 7

The requirement for black start services is not driven by the actions of Market Participants.

- It would be difficult to identify the causers of system wide failures that create the demand for black start services.
- Given this, black start pricing should be primarily focused on achieving cost recovery from beneficiaries. Specifically, the cost should be borne by loads.
- An appropriate billing attribute would be to allocate costs based on:
  1) Number of connection points; or
  2) A combination of connection points and Grid MWh consumed.

Non-Co-Optimized ESS

Observation 8 – Voltage Control & Transient and Oscillatory Stability

ESS associated with voltage control and transient and oscillatory stability provide for the transmission network to operate at higher capacity (in a similar manner to raising thermal transmission limits). Procured services to assist in these matters include generator operation to provide voltage support or increased stability.

The causers are both loads requiring power to be supplied and generators providing the power, and any transmission issues that require such services. Often these services are provided under network support contracts with the transmission entity (which may be a substitute for network investments).

The above indicates that:

- It is appropriate to recover these costs from loads (beneficiaries), given that the focus of this charge is cost recovery and typically not market efficiency.
- As these services are a substitute for network investments, it may also be appropriate for network operators to recover these costs via network access charges applied to final customers.

Given the above, it is appropriate that if WP procures the NCESS, it is recovered from network tariffs, whereas if procured by AEMO, it is recovered from loads (Grid MWh) via retailers.

Non-Co-Optimized ESS (continued)

Observation 9 – Fast Frequency Response

- In the NEM, Fast Frequency Response (FFR) refers to the delivery of rapid active power increase or decrease by generation or load in a timeframe of 2 seconds or less, to correct a supply – demand imbalance and assist in managing power system frequency. The FFR service is due to commence in October 2023.
- The requirement for this service is due to a reduction in system inertia due to the anticipated retirement of large synchronous generator units which are not being replaced. New generation will predominately be from inverter connected generation, including large scale solar PV, wind power, batteries and behind-the-meter distributed resources like rooftop solar, that do not provide sufficient inertia to stabilise system frequency.
- In relation to the FFR, the AEMC state[1] "The introduction of FFR services, which operate more rapidly than the existing frequency control services, will provide an additional frequency control option thereby reducing the overall costs of managing power system frequency relative to the status quo or other alternative arrangements."
- The causer of the requirement for this service is the same as the requirement for contingency reserve services (discussed previously). Costs should be allocated to the "causers" of variations in frequency on the same basis.

Note (1) https://www.aemc.gov.au/sites/default/files/2021-07/Fast%20frequency%20response%20market%20ancillary%20services%20infosheet.pdf

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Energy Policy WA

Agenda Item 7(a): Overview of Rule Change Proposals (as of 21 June 2022)

Market Advisory Committee (**MAC**) Meeting 2022_06_28

- Changes to the report since the previous MAC meeting are shown in red font.
- The next steps and the timing for the next steps are provided for Rule Change Proposals that are currently being actively progressed by the Coordinator of Energy (**Coordinator**) or the Minister.

Indicative Rule Change Activity Until the Next MAC Meeting

Reference	Title	Events	Indicative Timing
None			

Rule Change Proposals Commenced since the Report presented at the last MAC Meeting

Reference	Submitted	Proponent	Title	Commenced
None				

Rule Change Proposals Awaiting Commencement

Reference	Submitted	Proponent	Title	Commencement
None				

Rule Change Proposals Rejected since Report presented at the last MAC Meeting

Reference	Submitted	Proponent	Title	Rejected
None				

Rule Change Proposals Awaiting Approval by the Minister

Reference	Submitted	Proponent	Title	Approval Due Date
None				

Formally Submitted Rule Change Proposals

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
Fast Track Rule Change Proposals with Consultation Period Closed						
None						
Fast Track Rule Change Proposals with Consultation Period Open						
None						
Standard Rule Change Proposals with Second Submission Period Closed						
RC_2019_03	17/12/2020	ERA	Method used for the assignment of Certified Reserve Capacity to Intermittent Generators	High	Publication of Final Rule Change Report	31/12/2022
Standard Rule Change Proposals with Second Submission Period Open						
None						

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
Standard Rule Change Proposals with First Submission Period Closed						
RC_2014_05	02/12/2014	IMO	Reduced Frequency of the Review of the Energy Price Limits and the Maximum Reserve Capacity Price	Medium	Publication of Draft Rule Change Report	31/12/2022
RC_2018_03	01/03/2018	Collgar Wind Farm	Capacity Credit Allocation Methodology for Intermittent Generators	Medium	Publication of Draft Rule Change Report	31/12/2022
RC_2019_01	21/06/2019	Enel X	The Relevant Demand calculation	Medium	Publication of Draft Rule Change Report	31/12/2022
Standard Rule Change Proposals with the First Submission Period Open						

Pre-Rule Change Proposals

Reference	Proponent	Description	Next Step	Date
RC_2020_04	Rule Change Panel	Balancing Facility Loss Factor Adjustment	Consult with the MAC on the priority for development of a Rule Change Proposal	TBD

Rule Changes Made by the Minister and Awaiting Commencement

Gazette	Date	Title	Commencement
2022/67	17/05/2022	Wholesale Electricity Market Amendment (Network Access Quantities Procedure) Rules 2022	• Schedule A will commence on 01/09/2022 • Schedule B will commence on 01/03/2023 ○ Amending Rules can be found at Wholesale-Electricity-Market-Amendment-Network-Access-Quantities-Procedure-Rules-2022.pdf (www.wa.gov.au)
2021/212	17/12/2021	Wholesale Electricity Market Amendment (Tranche 5 Amendments) Rules 2021	• Schedule E will commence on 01/07/2022. • Schedule F will commence on 01/09/2022. • Schedule G will commence on 01/01/2023. • Schedule H will commence on 01/10/2023. • Schedule I will commence at times specified by the Minister in notices published in the Gazette.
2021/166	28/09/2021	Wholesale Electricity Market Amendment (Miscellaneous Amendments No. 2) Rules 2021	• Schedule F will commence on 01/07/2022. • Schedule G will commence at times specified by the Minister in notices published in the Gazette. ○ The Amending Rules specified in Part 1 of the commencement notice published on 17/12/2021 in Gazette 2021/212 will commence on 01/07/2022.
2021/96	28/05/2021	Wholesale Electricity Market Amendment (Miscellaneous Amendments No. 1) Rules 2021	• Schedule E will commence at times specified by the Minister in notices published in the Gazette: ○ The Amending Rules specified in Part 2 of the commencement notice published on 28/09/2021 in Gazette 2021/166 will commence on 01/07/2022.
20201/17	18/01/2021	Wholesale Electricity Market Amendment (Governance) Rules 2021	• Schedule C will commence immediately after the commencement of the Amending Rules in clauses 50 and 62 of Schedule C of the *Wholesale*

Gazette	Date	Title	Commencement
			Electricity Market Amendment (Tranches 2 and 3 Amendments) Rules 2020.
2020/214	24/12/2020	Wholesale Electricity Market Amendment (Tranches 2 and 3 Amendments) Rules 2020	• Amending Rules in Schedule C will commence at the times specified by the Minister in notices published in the Gazette: ○ The Amending Rules specified in Part 4 of the commencement notice published on 28/09/2021 in Gazette 2021/166 will commence on 01/09/2022. ○ The Amending Rules specified in Part 4 of the commencement notice published on 17/12/2021 in Gazette 2021/212 will commence on 01/09/2022. ○ The Amending Rules specified in Part 5 of the commencement notice published on 28/09/2021 in Gazette 2021/166 will commence on 06/12/2022.