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

Meeting Agenda

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	Tuesday 11 October 2022
Time:	9:00 AM – 11:00 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_08_23	Chair	Decision	2 min
4	Action Items	Chair	Noting	2 min
5	Market Development Forward Work Program	Chair/Secretariat	Discussion	5 min
6	Update on Working Groups			
	(a) AEMO Procedure Change Working Group	AEMO	Noting	2 min
	(b) Reserve Capacity Mechanism Review Working Group (**RCMWG**)	RCMRWG Chair	Noting	20 min
	(c) Cost Allocation Review Working Group (**CARWG**)	CARWG Chair	Discussion	45 min
7	Rule Changes			
	(a) Overview of Rule Change Proposals	Chair/Secretariat	Noting	2 min
8	Future Reviews	Chair	Decision	30 min
9	General Business	Chair	Discussion	8 Min
	Next meeting: Tuesday 15 November 2022 (move to a 9:00 AM start)			

Please note, this meeting will be recorded.

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

Minutes

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	23 August 2022
Time:	9:30am –11:57am
Location:	Videoconference (Microsoft Teams)

Attendees	Class	Comment
Sally McMahon	Chair	
Dean Sharafi	Australian Energy Market Operator (**AEMO**)	
Martin Maticka	AEMO	
Zahra Jabiri	Network Operator	
Genevieve Teo	Synergy	
Christopher Alexander	Small-Use Consumer Representative	
Noel Schubert	Small-Use Consumer Representative	
Geoff Gaston	Market Customer	
Patrick Peake	Market Customer	
Wendy Ng	Market Generator	
Jacinda Papps	Market Generator	
Rebecca White	Market Generator	
Paul Arias	Market Generator	
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
Tim Robinson	Robinson Bowmaker Paul (**RBP**)	Presenter

Apologies	From	Comment
Timothy Edwards	Market Customer	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30am with an Acknowledgement of Country. 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. The Chair welcomed Christopher Alexander is the new small-use consumer representative, and noted that Paul Keay would no longer be a small-use consumer representative and thanked Mr Keay for his contribution.	
3	**Minutes of Meeting 2022_06_28** The MAC accepted the minutes of the 28 June 2022 meeting as a true and accurate record of the meeting. The Minutes referred to in the combined meeting papers had the incorrect date of publication. The correct date of publication of the minutes of the 17 May 2022 meeting was 29 June 2022. **Action: The MAC Secretariat to publish the minutes of the 28 June 2022 MAC meeting on the Coordinator's Website as final.**	**MAC Secretariat**
4	**Action Items** The Chair noted there were no open action items.	
5	**Market Development Forward Work Program** The paper was taken as read and the Chair noted that the updates in red were to be reviewed and discussed. The following topics were discussed. • **The Reserve Capacity Mechanism (RCM) Review** The update was taken as read. • **The Cost Allocation Review (CAR)** The update was taken as read	
6	**Update on Working Groups**	
	(a) AEMO Procedure Change Working Group (APCWG) The paper was taken as read. Mr Maticka noted a typo in that the paper – it refers to the prudential arrangement procedure, but it was meant to be the prudential requirements procedure. Mr Maticka confirmed that there was no AEMO procedure change activity and noted that the APCWG would only be scheduled on an as needed basis while the WEM reform process was underway.	
	(b) RCM Review Working Group (RCMRWG) The papers for agenda item 6(b) were taken as read.	

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	Members noted the minutes of the RCMRWG meetings held on 14 and 21 July 2022. A substantive discussion on RCM Review was to be discussed under agenda item 8.	
	(c) CAR Working Group (CARWG) The paper was taken as read. The MAC was given an update on the progress of the CARWG. The MAC noted that the CARWG's findings are to be presented to the MAC in October 2022 and a draft Consultation Paper at a subsequent meeting.	
7	**Rule Changes** **(a) Overview of Rule Change Proposals** The paper was taken as read. There were no updates.	
8	**RCM Review Draft Consultation Paper** The Chair asked the MAC to review the working draft of the Consultation Paper for the RCM Review and to provide guidance to the Coordinator on the proposals and questions on the paper, noting that it was still being refined by EPWA. The intent was to determine: • does the MAC agrees that the design proposals have been clearly articulated and captured in the Consultation Paper; and • are the questions going to be helpful for the consideration of stakeholders. Ms Guzeleva noted the majority of stage one of the review had been covered in the Consultation Paper, but that some items had been deferred to stage two, such as the Relevant Demand Methodology and some of the economic modelling, and that some parts of stage one may be impacted by stage two, such as the review of the Individual Reserve Capacity Requirements (**IRCR**). Ms Guzeleva encouraged everyone to make a submissions on the Consultation Paper once it is published, noting that certification of intermittent generators is an open issue on which detailed feedback would be appreciated. • Mrs Papps indicated that the MAC had not endorsed all of the points made in the Consultation Paper, and that some issues are still to be determined, such as the 14 hour fuel requirement. Mrs Papps noted that it is a significant Consultation Paper and that Alinta has not yet had time to go into the detail or to do the necessary analysis. • The Chair noted that the paper did not intend to give the impression that the MAC had endorsed everything, rather that there were a lot of outstanding issues being worked through with the RCMRWG that were canvassed and explained in the Consultation Paper. The Chair noted that the intent was for the MAC to comment and recommend whether the Consultation Paper should be published in its current form.	

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	• Mr Sharafi made a comment in relation to the Draft Statement of Policy Principles: Penalties for High Emission Technologies in the Wholesale Electricity Market (**Principles**), which may affect the timeline for RCM Review, and questioned if the MAC would need to consider delaying issuing the Consultation Paper. o The Chair noted that the Consultation Paper acknowledged the Principles but that the Principles should not hold up the RCM Review, adding that it was not clear when the Minister would issue the final Principles. o Ms Guzeleva noted that the Principles would need to be amended as a result of the consultation with the MAC, and did not want to delay the RCM Review because finalizing the Principles could take months. Ms Guzeleva noted that there did not appear to be anything in the Consultation Paper that required any significant change, apart from the economic modelling, which could be done in stage two. o The Chair noted the minutes to the MAC meeting on 9 August 2022 have been released, which capture the MAC's discussion of the Principles. • Ms White agreed with Mrs Papps that the MAC had not endorsed all of the statements in the Consultation Paper because the MAC had provided differing views and feedback on several issues, and suggested checking that the paper correctly states when the MAC has endorsed an issue. o Ms Guzeleva noted that EPWA had been careful to check the minutes and that the paper used the term 'support' rather than 'endorse' when issues had been taken to the MAC and had general support, such as the Planning Criteria and flexibility capacity product. Ms Guzeleva asked the MAC to advise if there are any instances where the Consultation Paper indicates MAC support and the MAC disagrees. Ms Guzeleva advised that the Consultation Paper would be published on Monday 29 August 2022 and noted that it was the Coordinator's paper, not a MAC paper – if MAC members had significant comment, they would need to be provided within the next 24 hours and any other comments would need to be by submission following publication. The Chair asked the MAC to discuss each proposal, indicated that the MAC's feedback would be considered before the Consultation Paper is released, and suggested that each organisation will have an opportunity to provide feedback on the paper after publication. The Chair noted that MAC members have had the paper for a week and that any significant comments could be provided within 24 hours. Ms Guzeleva provided an overview of the design proposals with the MAC and asked the MAC to comment. **Proposal One – retain the 'Peak Capacity' product**	

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	Ms Guzeleva noted that this proposal had been to the MAC on several occasion and the minutes from those meetings clearly indicate that the MAC was comfortable with retaining the existing capacity product to provide an explicit price signal, several years in ahead of the actual capacity year.
	
	Mrs Papps agreed on this point and that the peak capacity product provides an important price signal, but noted we need to be careful to not make the signal to difficult, or it will not provide investment at the right time.
	
	Proposal Two – the RCM will not include a specific product to deal with minimum demand
	
	Ms Guzeleva indicated that the MAC supported that the RCM Mechanism will not deal with minimum demand, whilst being careful not to provide perverse incentives to exacerbate the minimum demand issue.
	
	• Mr Schubert supported this, providing that the minimum load project effectively addresses minimum demand.
	
	Proposal Three – introduce a new capacity product to incentivise flexible capacity
	
	Ms Guzeleva noted the proposal to add a second capacity product to incentivize flexible capacity that can start, ramp and stop quickly.
	
	• Mr Schubert noted that ability to start, ramp and stop quickly may not be sufficient because some generators have a minimum runtime or minimum restart time, and we do not want those restrictions on the flexible plant.
	
	Proposal Four – the Planning Criterion will not include a reference to volatility in operational load or output of intermittent generation
	
	Ms Guzeleva noted that volatility in real time operational load and intermittent generation over short time frames will be managed through the Essential Systems Service (**ESS**) market and that the Planning Criteria will not include any reference to volatility with respect to either load or output.
	
	• Mr Maticka sought to clarify whether we could be sure that we can manage the increasing amount of rooftop Photovoltaics (**PV**) through the ESS market and not controlling the ramp up of PV.
	  o Ms Guzeleva noted that the volatility from PV in the middle of the day would be dealt with by the low load project and be handled through ESS.
	  o Mr Maticka clarified that his question related more to the statement that we believe we can continue to manage the volatility through an ESS market, as he was not sure that this would be true or cost effective in the long term, and sought to understand the overall benefit.	

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	o Ms Guzeleva noted there was no proposal to procure a product to deal specifically with generation or load volatility, rather the ability to transition the system from the middle of the day to the evening peak through the afternoon ramp. Ms Guzeleva noted that load or generation volatility during any interval would be dealt with either by ESS or through the projects that are dealing with minimum load, effective management of PV and aggregation. o Mr Maticka noted that he misinterpreted that the term short timeframe is actually that transition over six hours rather that five minutes. o Ms Guzeleva noted the flexibility product is designed to address the ramping need from the minimum to the evening peak in the most extreme scenario, whether under 10% or 50% probability of exceedance (**POE**), and the idea is that a longer term signal is needed to bring about the capacity that can ramp up to the 2 GW/hour that AEMO is concerned about. The flexibility product is not dealing with volatility per se, which will be left to operation of the ESS market. o Mr Robinson noted that the analysis determined the amount of flexible capacity needed to cover the worst case ramp scenario, and if we have enough flexible capacity to meet this requirement, then it can also meet our needs for shorter term volatility. o Mr Maticka asked how far out the analysis projected for the worst case volatility scenario. Mr Robinson indicated that the analysis was conducted to 2050. o The Chair asked Mr Maticka whether proposal four needed to be clearer, or if some supporting information would be helpful to include in the Consultation Paper. Mr Maticka noted that it would be sufficient to reword this explanation in the Consultation Paper. • Mr Sharafi noted that, by 2050, AEMO may not be able to manage volatility of Distributed Energy Resource (**DER**) and that AEMO has seen about 20 MW/minute volatility. • Ms Guzeleva noted there was an expectation the major deliverables through the DER Roadmap will all go ahead and be fully implemented, and that the modelling takes into account some of these deliverables, including how electric vehicles will behave, and noted that not everything can be solved through the RCM. • Mr Schubert asked Mr Sharafi why there were not more generators on Automatic Generation Control when demand is volatile, noting that having only one or two generators manage frequency seems to be a key problem. Mr Sharafi noted there were a lot of generators on Load Following Ancillary Service (**LFAS**) to manage volatility.	

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	Proposal five – retaining the two current limbs of the Planning Criterion Ms Guzeleva noted that the MAC supported retaining the two current limbs of the Planning Criterion: the requirement to meet the 10% POE, and the Expected Unserved Energy (**EUE**) target, whichever is the greatest. **Proposal Six – amending the reserve margin** Ms Guzeleva noted that this was a substantive proposal to the current Planning Criteria, to move away from prescribing a fixed 7.6% to tackle unforced outage expectations and to not prescribe the size of the largest unit as setting the reserve margin, but to let AEMO annually determine the largest contingency at peak. Ms Guzeleva recalled that the MAC was comfortable with this. • Mr Sharafi noted AEMO was very supportive because it allows consideration of the largest system contingency. • Ms White sought to clarify whether MAC members were comfortable with the adjustment for forced outages and asked if the three-year outlook later in the Consultation Paper refers to something else. o Ms Guzeleva noted the 7.6% is the forced outage rate that is currently embedded in the criteria and asked Ms White if she would prefer to retain it. o Ms White noted that it was her recollection that others questioned this, but that her recollection may incorrect if no one else recalls this. o Ms Guzeleva noted that Ms White may be referring to the section on Installed Capacity (**ICAP**) and Unforced Capacity (**UCAP**) that comes later in the Consultation Paper. • Ms Teo sought to clarify which was the next reserve capacity cycle referred to on page 60 of the paper. Ms Guzeleva noted it was 2023 cycle, which has not yet commenced. The Chair asked EPWA to make sure this was clear. • Mr Gaston asked about the magnitude of the largest contingency at peak and whether there would be some kind of de-rating for the likelihood of those two things happening at the same time, noting this could be a huge number and that customers could pay huge amounts for this contingency. o Mr Sharafi noted that AEMO had not seen the system contingency bigger than generating contingency during peak times, but that this did not mean it could not happen in the future. Mr Sharafi could not quantify what this contingency will be and noted that this contingency is needed because, while it was not expected to be much larger, it could be.	

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	o Mr Gaston noted that he had heard that some of the lines up north potentially have 700 W contingency, which will push the cost through the roof. o Mr Sharafi noted that 700 MW was in condition of outages, and that AEMO will not allow that to happen, and that we have not seen the windfarms generating to that level during peak times. o Mr Gaston expressed concern in terms of what that is going to cost and whether we are talking about capacity here, not network contingencies. o The Chair noted there was a recognition that a network contingency could be bigger, which is why it needs to be captured, and asked Ms Guzeleva whether information about the magnitude or impact of this change could be included in the Consultation Paper. o Ms Guzeleva indicated that that it will be very difficult to include a number if AEMO does not know the magnitude and that it will change from year to year. Ms Guzeleva noted the Consultation Paper could be clarified that we are talking about the largest contingency at peak, even if that is driven by network. o Mr Gaston contended that this does not make sense because you can have all the generation you want and you are not going to meet your peak demands if you have a network contingency. o The Chair noted that she believed the concept was understood but that it could be beneficial to provide information on the impact of the change. o Ms Guzeleva suggested looking at the most recent hot season to see what would set the contingency – Collie or a potential network outage at peak. o Mr Gaston noted that the last hot season was probably the only one in 10 year peak in the last 20 years. o Mr Sharafi noted that the size of system contingency has not yet been larger than the size of generator contingency, and that this is something that AEMO and Western Power will not allow to happen because we need to work for the benefit of the customers, and need to be financially aware of the impact. o The Chair noted the proposal seemed to require further explanation and that it would be beneficial to provide a historical example in the Consultation Paper for context. o Mr Schubert noted that if it were to become very expensive, it would justify network augmentation to reduce the size of the	

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	network-caused contingency, and that this can hopefully be optimised. o Ms Guzeleva agreed and noted that Western Power now has the requirement under the new transmission planning in the rules to look at market impacts when they plan the network. o Ms Jabiri noted that Western Power can assist to ensure the wording from the network point of view reflects the optimum outcome to the customer. **Proposal 7 – the target EUE percentage in the second limb of the RCM Planning Criterion to remain at 0.002%** Ms Guzeleva noted the second limb of the Planning Criterion is currently set it 0.002% of the EUE, and will remain unchanged. The Chair noted that this proposal seems to be uncontroversial. **Proposal 8 – the Planning Criterion will include a third limb requiring AEMO to procure flexible capacity** Ms Guzeleva noted the Planning Criterion will include the third limb requiring AEMO to procure flexible capacity to meet the size of the steepest operational ramp expected on any day in the capacity year for either 10% to 50% POE. Ms Guzeleva indicated that the MAC had supported this proposal. **Proposal 9 – the ERA will remain responsible for determining the method to calculate the Benchmark Reserve Capacity Price (BRCP)** Ms Guzeleva noted this proposal this was discussed by the RCMRWG but not by the MAC. RBP presented some CSIRO analysis to the RCMRWG that suggests that an Open Cycle Gas Turbine (**OCGT**) is likely the least cost marginal entry in the WEM, but that OCGTs may be overtaken by storage as we move out of the current energy crisis. Therefore, it is proposed for the ERA to continue to be responsible for setting the BRCP, but to give some guidance to the ERA in the rules. Ms Guzeleva noted that, if network conditions in any particular year suggest that there is not an ability to connect a 160 MW OCGT, then the ERA would have to select a different size or another technology that may be more expensive but can be accommodated by the Network Access Quantity (**NAQ**) and capacity de-rating. **Proposal 10 – the WEM Rules will define the BRCP as the per MW capital cost of the new entrant technology with the lowest expected capital cost amortized over the expected life of that facility** Ms Guzeleva noted that a BRCP would be calculated for both the peak capacity and flexibility products, and will differentiate between the two because we expect that even an OGCT may need some additional capital to be able to ramp, start or shut down in accordance with the requirements for the flexibility product. The two components of the BRCP would always have to account for oversupply of capacity	

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	in either product, but the Reserve Capacity Price for the flexibility product would never be lower than the peak product because we expect a facility that can provide both products will receive an uplift when the BRCP for the flexibility product is higher. • Mr Sharafi noted that he does not suggest changing the reference technology at this stage but that barriers to entry of OCGTs need to be considered because it will be hard to bank an OCGT project. • Ms Guzeleva noted that we do not want to spell out in the rules that OGCT is the reference technology – rather that it should be the least cost, most efficient technology that can enter the market in the capacity cycle, taking into account potential network constraints. • Mr Peake noted that a lot of time was spent discussing whether we should have a BRCP for both gas turbines and battery storage and asked whether this should be discussed a little more. Mr Peake noted question (10)(b) about whether we support calculating separate BRPCP's for the peak and flexible products, but thought there was also a question of whether we should have a separate capacity price for storage given that we are trying to encourage storage onto the system. o Ms Guzeleva indicated that she did not recall a discussion of having two capacity prices for the peaking product, but that there was discussion about when storage will become the most efficient marginal entry, at which point the BRCP would need to be based on storage. There was also a discussion about whether the ERA should not consider moving to a net cost of new entry (**CONE**) because the short run marginal cost of storage may be much lower than an OCGT. o Ms White asked what would happen if the cheapest technology for the peak product was not able to provide the service that we need for the flexible product. Ms White was unclear why you would use the same reference technology for the two products. o Ms Guzeleva noted that in the rules are not going to set the reference technology and that the Consultation Paper stated that if OGCT cannot be built, then the reference technology will have to change. There was extensive discussion at the MAC meeting on 28 August 2022 regarding the Principles, and that plant utilization would need to be considered in the penalties, which makes sense because we are looking at the totality of emissions. o Ms Guzeleva indicated that she does not think that the rules should prevent a different reference technology for the flexibility product and the flexibility price may be higher in most circumstances, unless we end up with an enormous oversupply. Ms Guzeleva noted she would clarify the wording	

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	in the Consultation Paper that different reference technologies can be set for the peak and flexibility products. o Mr Robinson agreed that the intention is for the reference technology to be flexible and for it to be possible to have two separate technologies, although this will not be the case in the foreseeable future. • Mrs Papps raised a question about proposals, 9, 10 and 11, noting that it seems that the reference technology may be reviewed annually, as it feeds into the BRCP calculation, and she was uncertain about how the five yearly review versus an annual review process might work. Mrs Papps also sought clarity on the ERA decisions to use net vs gross CONE on a yearly basis and whether this would provide enough signaling, and was keen to understand the differences between the reviews and what this might mean in practice on a year-to-year basis o Ms Guzeleva noted she would make sure that the rules are drafted to provide for a review as soon as there is a crossover of technologies, and it would be a good idea to give the ERA the ability to closely watch the reference technology. o Mrs Papps noted that the reviews need to happen with enough notice to not cause issues for investment and it needed to be determined whether the ERA: ▪ is to work out the cost of every new entrant technology; and ▪ will be doing detailed modelling every year or if there should be triggers to indicate that the ERA should conducted a review. o Ms Guzeleva noted that the rules would be flexible and acknowledged Mrs Papps' point about certainty and when new technology becomes the reference technology. **Proposal 11 – the BRCP methodology can use the gross CONE approach if the reference technology has the highest short-run costs in the fleet** Ms Guzeleva noted this proposal related to use of net vs gross CONE and the NAQ, and noted that the Consultation Paper would need to be adjusted, as it talks about giving the ERA guiding principles in the rules for setting the BRCP, but it is a consideration whether to move to the net CONE or retain the gross CONE. The second point in the proposal means, if there is a situation where the least cost new entry cannot be accommodated at any part of the network, then the ERA would need to consider using whatever the next lowest technology can be accommodated. • Ms White asked whether using net CONE breaks down the concept of receiving capital or fixed costs from that RCM and variable costs from the energy market, as it sounds like a	

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	participant will not receive their full capital costs from the RCM in some circumstances. o Ms Guzeleva noted that this was discussed by the RCMRWG and that net CONE only needs to be considered if the reference technology is not the least short run marginal cost technology in the energy market. o Mr Robinson added that the concept of recovering capital costs from the RCM and variable costs from the energy market applies for that reference technology at the moment, which is an OCGT. Other facilities that have higher fixed costs than an OCGT already recover part of their fixed costs in the energy market. There are many facilities in the WEM that recover fixed costs partially from the RCM and partially from the energy market. o Mr Robinson indicated that the paradigm will be blurred once storage becomes the reference technology. Mr Robinson indicated that, if we keep BRCP based on the gross CONE of a storage facility, it will recover its full fixed costs from the RCM and then also get a contribution from the energy market, but then consumers are paying more for capacity than they need to. • Ms White asked whether we are comfortable there will not be revenue adequacy issues, noting that some generators were bidding below their marginal cost to run – not to get paid, because they get paid through their contract which does change the market dynamics. Ms White noted that the ERA analysis indicated there will be a downward trend in energy prices and that they would not be sufficient to encourage investment. o Ms Guzeleva noted that this is a controversial issue and the Consultation Paper says that the ERA must consider whether the use of gross CONE remains adequate if it swaps to a reference technology that is not the highest short run marginal cost in the energy market. Ms Guzeleva reminded MAC members that EPWA was looking for submissions on this issue, but noted that, while some RCMRWG members expressed this concern, others had the view that rents should not be transferred to generators by design, rather than in competitive behaviour in the market. o The Chair noted that, if the RCM is a signal for future investment in capacity, we have to assume that that capacity may never run, then what assumptions do you make to come up with a net CONE. The Chair noted that the proposal is for the ERA to deal with these issues rather than specify a net CONE outcome. o Ms Guzeleva noted that the rules will need to contain principles for this determination, and that sufficient investment	

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	incentives need to be balanced against the consumer interest of not transferring unnecessary rent to providers. o The Chair noted the need to think about the impact on incentives if someone wants to build capacity but they know that they will have to operate in another market before they make any money from that capacity. • Ms Teo suggested that the BRCP must cover all costs for the marginal unit, given the intention of the RCM is to cover the just in case capacity. Ms Teo noted that large costs associated with the 14 hour fuel requirements are not covered by the BRCP and asked if that could be made clearer in the Consultation Paper. o Ms Guzeleva indicated that fuel is in principle not covered by the BRCP, which only considers fixed costs. o Mr Robinson noted that if part of the facility's fixed cost include a diesel tank, then this should be included the assessment of the BRCP. **Proposal 12 – the administrated RCM price curve for the flexible capacity product will be the same as is used for the peak product** Ms Guzeleva noted this the price curve for the flexible product needs to have a signal about over- and under-supply of capacity. There will potentially be two price curves, but if the flexible capacity product is oversupplied, that price will collapse back to, but will never be lower than the price for the peak product. A facility will be able to ask for a five-year fixed price period for the flexible capacity product, as it can for the peak product. • Mr Peake noted that some facilities, such as pump storage, may need longer than a five-year period. If the reserve capacity price drops away quickly after five years, which it would do if there is any excess, there will not be the ability to get a return on that investment. o Ms Guzeleva noted that the RCM has an administrated price arrangement and that RCM prices in an auction would collapse if there was oversupply, which is the point. Policymakers need to strike the balance between certainty and making sure consumers are not paying for something that they do not need. Ms Guzeleva noted that the five-year guarantee is currently in the rules and not part of this particular reform. We may need to look at whether five years is sufficient when we move to de-rating of storage, but this will need to be linked to evidence. o Mr Peake indicated that he understood this, but that capacity has only left the market due to government decree, not due to the drop in price. Mr Peake suggested that we need to question how to make sure we do not get a surplus or shortage and to make sure that there is enough money on the table to replace what plant is been removed from the system,	

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	noting that the ERA has said there is not enough money for batteries or gas turbines. Mr Peake suggested that one curve has the danger of crippling the whole process. o Ms Guzeleva noted the ERA study was clearly talking about carbon not being priced in the market, which is a serious concern, but is not addressed by the current RCM design. Ms Guzeleva noted that the ERA has given a presentation where they made the point that the flexibility product would help, but may be not covered the entire gap. Prices in the market would collapse if we were to opt for an auction and there was an oversupply. • Ms Guzeleva indicated that EPWA would take on board comments about the pricing reform that was implemented in 2020. The modelling suggests that the price curve in WA is shallower than elsewhere and there may be a need to send a sharper signal at the upper end of the curve if we face a shortage. o The Chair suggested that the Consultation Paper should note the need to review the price curve and the five year guarantee, and that stakeholders can then comment. o Ms Guzeleva reminded MAC members that the price curve is reviewed by the ERA. o Mr Alexander asked Mr Peake how many years' guarantee he thought would be adequate. Mr Peake replied something closer to 10 years, but that this would depend on the technology and life cycle. Mr Peake noted that he believed that the consultants have said that there are other mechanisms with 10-year price guarantees and that prices drop quickly after that. Mr Peake agreed with the Chair that the Consultation Paper should indicate that this requires review. o Ms Guzeleva noted that the ERA is required to review the factors in the price curve, with public consultation, and noted that stakeholders raised the issue of the five years, which will be logged and considered outside of the RCM Review. • The Chair suggested adding some context to the Consultation Paper to indicate that these matters need to be reviewed, that the mechanism needs to provide signals for the appropriate technologies and must ensure that consumers are not paying more than necessary for the capacity. **Proposal 13 – the current Availability Classes will be removed from the WEM Rules** • Mrs Papps raised concern that there was not enough analysis about why 14 hours of fuel is needed for Class One, and noted that, whilst this may be valid for some base load facilities, this is not the case for all facilities. Mrs Papps noted that the RCMRWG had not landed on a position on this matter.	

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	o Mr Robinson indicated three points that support the 14-hour fuel requirement: ▪ this fuel requirement would allow a diesel facility to run for 4-5 hours over a 3-day period, without resupply; ▪ the availability duration gap in later years is moving to a 14-hour period over night; and ▪ the policy is not to reduce the current amount of system reliability. o The Chair noted the Consultation Paper does not step through the need for a 14-hours fuel requirement and that this issue has been raised at the MAC on numerous occasions as an unnecessary/costly requirement. Stakeholders can directly address the rationale if it is articulated in the paper. o Mrs Papps noted that the requirement is to have enough fuel for the peak trading intervals on business days, but if we are now considering overnight fuel requirements, then this might change how generators contract going forward. Ms Papps sought to clarify what timeframe that 14 hour requirement was over. o Mr Peake noted that a generator would need a contract which gives them 14 hours/day of gas, day in, day out, and that this would need to be signed up three years in advance, and that this is discriminatory against small operators. • Mr Huxtable noted that it is not clear in the Consultation Paper that loads and behind the meter (**BTM**) storage will be treated similarly to wind or solar generation, and that this should be highlighted so that customers can comment on this fact if they are going to have a BTM battery and their load and battery will be treated as one. **Proposal 14 – AEMO will determine an availability duration requirement for Capability Class 2 facilities** Ms Guzeleva noted the modelling has uncovered a duration gap that will get longer over time and will blend with overnight load, and that AEMO would have to start changing the availability in the Electricity Statement of Opportunities (**ESOO**) for Capacity Classes 1 and 2 to cover the duration gap. The Consultation Paper proposed that facilities will keep their certified capacity for five years after commissioning (i.e. a 4 hour battery will receive 100% of its certification for five years, and if the duration gap becomes 8 hours, then the 4 hour facility will be certified for 50% after five years). The RCMRWG has mixed views on this proposal and it has not been discussed in detail with the MAC. Ms Guzeleva noted that the five-year period may need to be extended if it becomes desirable to incentivize new technology in the market, such as longer term storage.	

Item	Subject	Action
	• Mr Peake noted that changing the duration gap would change the value of the storage, so AEMO and the ERA will need to have the same time schedule for when they undertake their review. • Ms Guzeleva noted that it is AEMO's role to determine the duration gap in the ESOO and if the reference technology goes to six hour storage, then the ERA would need to factor this into the BRCP. Ms Guzeleva indicated that this would be made explicit in the Consultation Paper. **Proposal 15 – Certified Reserve Capacity (CRC) allocation will remain on an ICAP basis with refunds payable for forced outages** Ms Guzeleva noted that the RCRWG had considered analysis of the pros and cons around ICAP and UCAP, and whilst UCAP has some strong incentives, it is proposed to stick with ICAP, which does not take into account forced outages in certification. • Mrs Papps noted the proposal that, if a facility has a forced outage rate higher than 10%, then AEMO would be required to reduce its CRC by the entire forced outage rate, and that is big penalty (Ms White agreed). Mrs Papps also noted that different participants log forced outages in different ways – a facility must log a forces outage to its max capacity if it deviates from a dispatch instruction, but this is not a real forced outage, which could skew this data, and Synergy does not have dispatch instructions. Mrs Papps noted that, if we are looking at a forced outage rate for the three years prior, we might have to take into consideration that forced outages at the moment have two different types – true forced outage when you are completely forced off and deviations around dispatch instructions. o Ms Guzeleva noted Mrs Papps' points were valid and would be noted for the rules drafting if these proposals, if approved. o Mr Robinson agreed with Mrs Papps' point about Synergy not having dispatch instructions but took issue with the characterization that failing to meet dispatch is not a real forced outage. o Mrs Papps noted that you have to log a forced outage if you are out of tolerance and one of Alinta's units is traditionally slow to ramp, and it will have to log forced outages for that. o Mr Robinson queried whether the plant is incapable of meeting its capacity obligation. Mrs Papps indicated that was not the case and that bidding over a 30 minute period is different to a 5 minute interval. **Proposal 16 – AEMO will procure expert reports to ensure independence of estimates of intermittent generator output** Ms Guzeleva noted that the proposal is for AEMO to procure the expert reports on behalf of participants, to avoid the potential for overestimation, to ensure independence and to avoid potential bias.	

Item	Subject	Action
	• Ms White noted concern with regard to: o Managing conflict of interest in selecting experts that do not work for competitors; and o intellectual property – would the market participant have the rights to the report? • Mrs Papps noted that: o expert reports are expensive and consideration would need to be given to how AEMO would manage costs; and o it would be beneficial to have a procedure or methodology so that market participants are aware of the basis for AEMO to procure reports. **Proposal 17 – the methodology to assign CRC to facilities in each of the different Capability Classes will differ by class** Ms Guzeleva noted that the RCMRWG given some consideration to the methodology to assign CRC to the different capability classes but that it needs to be considered further, including during the IRCR discussions. Ms Guzeleva noted that a recommendation has not been made on CRC allocation for Capability Class 3. Ms Guzeleva flagged three alternatives: Effective Load Carrying Capacity (**ELCC**), Alinta's proposal and Collgar's proposal; and indicated that comments would be appreciated before determining which option best meets the objectives of the review. Ms Guzeleva indicated that the methodology must be a realistic, accurate representation of the capacity that would be available during peak intervals. Ms Guzeleva noted that it is difficult to design a method that represents of what will be achieved in a 10% POE event. • Ms White suggested that the table comparing the options should give the Delta Method a cross because of its volatility. Ms White asked what the extra modelling will seek to achieve and how participants will be able contribute. • Ms Guzeleva indicated that EPWA will advise when the RCMRWG will resume discussing these issues. • Mr Robinson noted that, to be comparable, the options must be modeled on the same basis, using the same data. RBP will replicate all of the modelling and to publish the inputs, method and results. • Ms White noted it would be useful for this modelling to account for the Principles. The Chair noted that any further specific feedback on the Consultation Paper would be helpful, but it will need to be provided by noon on 24 August 2022.	

Item	Subject	Action
9	**General Business** • Draft Statement of Policy Principles: Penalties for high emission technologies in the Wholesale Electricity Market o The Chair suggested circulating the a draft MAC response to the Principles, accounting for the edits proposed by Mrs Papps on 17 August 2022, for final comment, and then sending it to the Coordinator along with the minutes from the MAC meeting on the 9 August 2022. • The next MAC meeting is scheduled for 11 October 2022.	

The meeting closed at 12:00am.

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

Agenda Item 4: MAC Action Items

Market Advisory Committee (**MAC**) Meeting 2022_10_11

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
7/2022	MAC Secretariat to publish the minutes of the 28 June 2022 MAC meeting on the Coordinator's Website as final.	MAC Secretariat	2022_08_23	**Closed** The minutes were published on the Coordinator's Website on 25 August 2022.

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

Agenda Item 5: Market Development Forward Work Program

Market Advisory Committee (**MAC**) Meeting 2022_10_11

1. Purpose

- To provide an update on the Market Development Forward Work Program provided in Table 1, including:
  - the Chair of the Reserve Capacity Mechanism Review Working Group (**RCMRWG**) is to update the MAC on the progress of the Reserve Capacity Mechanism (**RCM**) Review since the last MAC meeting – see Agenda Item 6(b);
  - the Chair of the Cost Allocation Review Working Group (**CARWG**) is to update the MAC on the progress by the CARWG since the last MAC meeting – see Agenda Item 6(c) and
  - draft Scopes of Work for two potential reviews are to be discussed under Agenda Item 8:
    - Review of the Procedure Change Process Review;
    - Review of the Participation of Demand Side in the Wholesale Electricity Market;
- 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@dmirs.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 (**RCMRWG**). Information on the Working Group is available at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group, including: o the Terms of RCMRWG, as approved by the MAC; o the list of RCMRWG members; and o meeting papers and minutes from the RCMRWG meeting on 20 January 2022, 17 February 2022, 17 March 2022, 5 May 2022, 2 June 2022, 16 June 2022, 14 July 2022 and 2 July 2022. • The Chair of the RCMRWG will update the MAC on the progress on the RCM Review since the last MAC meeting – see Agenda Item 6(b). • The following papers have been released and are available on the RCM Review webpage at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review: o the Scope of Works for the review, as approved by the Coordinator; o the Stage 1 Consultation Paper; o the Paper on the Review of International Capacity Mechanisms; and o submissions on the Stage 1 Consultation Paper. • The RCMRWG will meet on 13 October 2022 to discuss options for implementing the draft policy statement regarding penalties for high emissions technologies. • Further analysis of the options to allocate Certified Reserve Capacity (**CRC**) will be presented to the MAC on 15 November 2022. • A full update on the timeline is provided under Agenda Item 6(b).

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
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 • Issues 2, 16, 23 and 35 from the MAC Issues List (see Table 3).	• The MAC has established the Cost Allocation Review Working Group (**CARWG**). Information on the CARWG is available at https://www.wa.gov.au/government/document-collections/cost-allocation-review-working-group, including: o the Scope of Work for the review, as approved by the Coordinator; o the Terms of Reference for the CARWG, as approved by the MAC; o the list of CARWG members; and o meeting papers and minutes from the CARWG meetings on 9 May 2022 and 7 June 2022 ; and o meeting papers from the CARWG meetings on 30 August 2022 and 27 September 2022. • The Chair will update the MAC on the progress by the CARWG since the last MAC meeting – see Agenda Item 6(c).
Procedure Change Process Review	A review of the Procedure Change Process to address issues identified through Energy Policy WA's consultation on governance changes.	• This review is proposed to commence in 2023 and a draft Scope of Works for this review is provided under Agenda Item 8. The MAC will be asked to consider this Scope of Works and advise on the priority, the scope and timing for the review.
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.

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
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.
Review of the Participation of Demand Side in the Wholesale Electricity Market (**WEM**)	The scope of this review is to: • identify the different ways that Loads/Demand Side Response can participate across the different WEM components; • identify and remove any disincentives or barriers for Loads/Demand Side Response participating across the different WEM components; and • identify any potential for over- or under-compensation of Loads/Demand Side Response (including as part of 'hybrid' facilities") as a result of their participation in the various market mechanisms.	• Based on comments provided by Market Participants, including during the RCM Review discussions, Energy Policy WA has identified that there may be a need to review how Loads/Demand Side Response can participate across the different WEM components under the WEM Rules. The intent of this review is to ensure that Loads/Demand Side Response have incentives to participate in the WEM and are compensated adequately for their participation. • A draft Scope of Works for this review is provided under Agenda Item 8. The MAC will be asked to consider this Scope of Works and advise on the priority, the scope and timing for the review.

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 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, 11 October 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 11 October 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**
Department of **Mines, Industry Regulation and Safety**
Energy Policy WA

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

Market Advisory Committee (**MAC**) Meeting 2022_10_11

1. Purpose

To update the MAC on the progress of the Reserve Capacity Mechanism (**RCM**) Review since the last MAC meeting, including the revised next steps for the review.

2. Recommendation

That the MAC note:

- the publication of the Consultation Paper for Stage 1 of the RCM Review on the Coordinator's website;
- the publication of submissions on the Consultation Paper on the Coordinator's website; and
- the revised next steps for the RCM Review.

3. Process

- The MAC discussed a draft of the Consultation Paper for Stage 1 of the RCM Review at its meeting on 23 August 2022.
- The RCM Review Working Group (**RCMRWG**) has not met since the last MAC meeting on 23 August 2022.
- The Coordinator published the Consultation Paper, reflecting the advice received from the MAC, on 29 August 2022.
- The submission window for the Consultation Paper was extended following stakeholder requests and was closed on 29 September 2022.
- The Coordinator received 12 submissions to the Consultation Paper and published these submissions on the Coordinator's website on 30 September 2022 at [Reserve Capacity Mechanism Review (www.wa.gov.au)](www.wa.gov.au).[1]
- At the time of preparing this paper, Energy Policy WA had not had the opportunity to develop a summary of the submissions, so a short verbal update will be provided at the MAC meeting on 11 October 2022.

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[1] Submissions were received from:

- AEMO;
- Alinta Energy;
- Australian Energy Council;
- Change Energy;
- Collgar Wind Farm;
- the Expert Consumer Panel;
- EnerCloud;
- Perth Energy;
- Shell Energy;
- Synergy;
- Tesla; and
- Western Power

- Feedback from stakeholders in several of the submissions to the Consultation Paper stressed the importance of the need for the Certified Reserve Capacity (**CRC**) allocation mechanisms to provide appropriate investment signals for intermittent generation.
- Energy Policy WA met with the Australian Energy Council and with several of its members on 4 October 2022, when the participants indicated broad support for Energy Policy WA to consider the proposed 'Hybrid' allocation method, as proposed by Collgar.
- As a result, further analysis will be undertaken to ensure that any preferred method adequately recognises the need for investment certainty, while confirming that the reliability objectives of the RCM would continue to be met.

4. Next Steps

Energy Policy WA will undertake further analysis that:

- ensures that any preferred method meets the primary objective of the RCM to ensure system reliability;
- recognises that the RCM should also provide certainty for investment; and
- models against the above:
  - o the various options for allocating CRC to intermittent generation, including the Delta Method, the Hybrid Method (as proposed by Collgar) and the Revised Hybrid Method (as revised by Energy Policy WA); and
  - o if necessary, further options to address stakeholder concerns regarding volatility of CRC allocations.

Therefore, Energy Policy WA has revised the timeline for the RCM Review to provide time for further analysis and consultation, as follows:

Committee	Date	Comments
RCMRWG	13 October 2022	Discuss options for implementing penalties for high emissions technologies.
RCMRWG	20 October 2022	Cancelled.
	28 October 2022	Deadline for feedback on the options for implementing penalties for high emissions technologies.
MAC	15 November 2022	Discuss the issues identified by the analysis of the options for allocating CRC to intermittent generation to date, the relevant issues raised by stakeholders and the further analysis to be undertaken to address these issues.
RCMRWG	24 November 2022	Discuss modelling results for the options to implement the policy for penalties for high emissions technologies.
MAC	13 December 2022	Discuss options to implement the policy for penalties for high emissions technologies.
RCMRWG	15 December 2022	Discuss the updated modelling results for the options to assign CRC to intermittent generators.

Committee	Date	Comments
MAC	31 January 2023	Discuss the updated modelling results for the options to assign CRC to intermittent generators, and a preferred option.
RCMRWG	February 2022	Discuss CRC for Demand Side Programmes (**DSP**s), Individual Reserve Capacity Requirements (**IRCR**) and outages.
MAC	March 2022	Discuss CRC for DSPs, IRCR and outages.

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

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

Market Advisory Committee (**MAC**) Meeting 2022_10_11

1. Purpose

To provide an update to the MAC on the progress of the Cost Allocation Review Working Group (**CARWG**) and to seek the MAC's views on a number of preliminary recommendations.

2. Recommendation

That the MAC:

(1) notes the minutes from the CARWG meeting on 30 August 2022 (**Attachment 1**);

(2) notes the update provided below and in the attached slide pack (**Attachment 2**) regarding further progress made by the CARWG on 27 September 2022; and

(3) provide views on the recommendations summarised on slides 5-7 of the attached slide pack.

3. Background

The CARWG met on 27 September 2022, where it discussed:

- options and recommendations for allocating Market Fees;
- options, preliminary recommendations and next steps for allocating frequency Regulation costs;
- further analysis that is to be done to finalise recommendations for allocation of Contingency Raise costs;
- questions and next steps to finalise recommendations for allocation of Contingency Lower costs;
- recommendations for allocation of Rate of Change of Frequency Control (RoCoF) Services costs;
- recommendations for allocation of System Restart costs; and
- recommendations for allocation of Non-co-optimised Essential System Services costs.

The attached slide pack (Attachment 2) is an updated version of the slides presented to the CARWG on 27 September 2022 that reflects the views of the CARWG. This slide pack provides recommendations, which were updated following the 27 September 2022 CARWG meeting, for consideration and agreement by the MAC.

4. Next Steps

• CARWG to consult on the outstanding matters	25 October 2022
• MAC to review a draft Consultation Paper	13 December 2022
• publish the Consultation Paper	Mid December 2022
• submissions due on the Consultation Paper	February 2023
• MAC to review a draft Information Paper	March 2023
• publish the Information Paper	April 2023
• draft a Rule Change Proposal in consultation with the MAC	May-June 2023

5. Attachments

(1) CARWG_2022_08_30 – Minutes of Meeting

(2) Cost Allocation Review – Assessment of Cost Allocation Options

Agenda Item 6(c) – Attachment 1

Government of **Western Australia**
Energy Policy WA

Cost Allocation Review

Assessment of Cost Allocation Options

Market Advisory Committee – 11 October 2022

Presenter: Grant Draper, Marsden Jacob Associates

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

Agenda

- Timeline and Purpose
- Assessment of Cost Recovery Options
  - (a) Allocation of Market Services Costs
  - (b) Allocation of Frequency Regulation Costs
  - (c) Allocation of Contingency Reserve Raise Costs
  - (d) Allocation of Contingency Reserve Lower Costs
  - (e) Allocation of Other ESS Costs
- Next Steps

Timeline and Purpose

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-September 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

Guiding Principles

1. Meet the Wholesale Market Objectives (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
4. Use the causer-pays principle, where practicable and efficient
5. Use the beneficiary-pays principle where appropriate

Summary of Recommendations

Service	Causers	Assessment	CARWG Feedback	MAC Direction Sought
Market Services	• Market generators • Market customers • Network Operators • DER / final customers (including DER)	• Developed and assessed four options: o current practice o NEM Method o WEM Hybrid Method o Market customers only	• Some generators supported allocating 100% of Market Fees to market customers • Some generators supported the WEM Hybrid Method • Other generators supported retaining the existing allocation method • Small-use customer representative supported the WEM Hybrid Method	• MAC to discuss and provide views on the benefits of, and preference for either: o further developing the WEM Hybrid Method o retaining the current method
Frequency Regulation	• Scheduled Generators • Semi-Scheduled Generators • Loads (including DER)	• Developed and assessed three options: o current practice o Current NEM Causer Pays Method o Tolerance Method • Identified a new NEM Causer Pays Method (still under assessment)	• General support for moving to a causer-pays method • CARWG needs more information on the new NEM Causer Pays Method	• MAC to note: o AEMO and EPWA to arrange a detailed explanation of the new NEM Causer Pays method for CARWG o Marsden Jacob to assess the impact of the new NEM Causer Pays method on Market Participants

Summary of Recommendations

Service	Causers	Assessment	CARWG Feedback	MAC Direction Sought
Contingency Reserve Raise	• Scheduled Generators • Semi-Scheduled Generators	• Refinement of application of the runway method to address potential 'over-recovery' of costs from aggregated facilities	• CARWG agreed that further work is required to ensure that the runway method only applies to 'credible' contingency events for a specific power station • Consideration to be given to treatment of facilities with multiple units that can be operated separately and are connected separately (e.g., Collgar Wind Farm)	• MAC to note: o recommendations on how the runway method could be altered to ensure appropriate costs recovery from Aggregated Facilities and from power stations comprising independently dispatchable units with separate network connections
Contingency Reserve Lower	• Small and large Loads • Energy Storage (recharge)	• Develop a modified runway method	• Support for developing a modified runway method to capture the likely increase in service requirements (and costs) from the entry of large-scale BESS and pumped hydro • Network outages and the loss of major loads (i.e., 30 MW) are not likely to be the major causer of future costs • Focus on applying the runway method (accurate cost attribution) to facilities above 120 MW	• MAC to support: o EPWA to develop and assess a modified runway method for Contingency Reserve Lower costs

Summary of Recommendations

Service	Causers	Assessment	Recommendation
RoCoF	• Scheduled Generators • Semi-Scheduled Generators • Loads (including DER)	• No further assessment required	• MAC to support: o Recommendation for no change
System Restart	• No specific causer	• No further assessment required	• MAC to support: o Recovery from market customers should be consistent with the billing attributes used to recover Market Services costs
Non-co-optimised ESS	• Network Operators	• No further assessment required	• MAC note the following: o Recovery from market customers should be consistent with the billing attributes used to recover Market Services costs

Note: Recommendations were provided in the slide pack for the CARWG for its meeting on 27 September 2022 for these three services, but the CARWG did not have time to discuss the recommendations

(a) Allocation of Market Fees

Market Fees Cost Allocation

MAC supported:

- High priority for assessment of alternative methods to allocate Market Fees
- Three options to be developed and compared with the current allocation method in the WEM
  - NEM Method
  - WEM Hybrid Method
  - Market customers only (added after the CARWG meeting on 30 August 2022)

Options for Allocation of Market Fees

Current WEM Method

- Each Market Participant is charged fees based on their Metered Schedule for all their Registered Facilities and Non-Dispatchable Loads for all Trading Intervals for the day

NEM Method

- Split between generators, market customers and TNSPs (based on directly attributable costs, un-attributable costs are allocated to market customers)
- For market generators
    - 50% charged on capacity (MW)
    - 50% on grid generation (MWh)
- For market customers
    - 50% based on grid demand (MWh)
    - 50% based on number of connections

WEM Hybrid Method

- 50% split between Market Participants selling and buying WEM services
- For Market Participants selling WEM services
    - 50% charged on capacity (MW)
    - 50% on generation output (MWh)
- For Market Participants buying WEM services
    - 50% based on grid demand (MWh)
    - 50% based on IRCR (MW)

Market customers only

- 50% based on grid demand (MWh)
- 50% based on IRCR (MW)

AEMO WEM Fees 2022/23

WEM Fees	Budget	Notes
Revenue Requirement	$41.9m	
Consumption	17,950 GWh	
WEM Market Operator Fee	$0.4913/MWh	
WEM System Management Fee	$0.6646/MWh	
WEM Fee	$1.1559/MWh	Paid by generators and loads
WEM Fee benchmark	$2.3118/MWh	Impact on loads
Derived Annual Revenue	$41.9m	Cost recovery
Market participant buying WEM Services – annual revenue	$20.95m	50%
Market participant selling WEM services – annual revenue	$20.95m	50%

Market Services Cost Recovery by Method – Fees ($ per annum)

Allocation of AEMO Market Fees Only - 2022-23				
Cost Allocations by Participant Type	**Current WEM Method $**	**NEM Method $**	**Market Customer only $**	**WEM Hybrid Method $**
Wholesale Market Participant	20,950,298	16,395,587	0	20,950,149
Market Customers	20,950,298	20,371,780	41,900,000	20,950,000
Western Power	0	5,132,750	0	0
Total	41,900,596	41,900,117	41,900,000	41,900,149
Cost Allocations to Generators Only	**Current WEM Method $**	**NEM Method $**	**Market Customer only $**	**WEM Hybrid Method $**
SYNERGY	8,095,565	6,713,114	0	8,577,963
ALINTA	3,496,297	2,855,362	0	3,648,559
OTHER	9,358,436	6,827,110	0	8,723,627
Total	20,950,298	16,395,587	0	20,950,149
Cost Allocations to Customer Type (via direct charges on Market Customers Only)	**Current WEM Method $**	**NEM Method $**	**Market Customer only $**	**WEM Hybrid Method $**
Residential (no BTM DER)	9.58	13.40	25.84	12.92
Residential (3 kW Rooftop PV)	7.14	12.23	23.42	11.71
Residential (5 kW Rooftop PV)	3.88	10.66	20.19	10.09
Small Business (no BTM DER)	25.81	21.22	64.08	32.04
Small Business (10 kW Rooftop PV)	12.96	15.03	51.35	25.68
Large Commercial (no BTM DER)	6,278.87	3,033.00	11,986.01	5,993.00
Large Commercial (250 kW Rooftop PV)	6,122.57	2,957.72	11,687.64	5,843.82

Note: Based on public SCADA generation data (not loss adjusted)

Allocation to Market Generators

Participant	Plant_ID	Annual GWh	Maximum Capacity (MW)	Capacity Factor	Current WEM Method Fee $	NEM Method/ WEM Hybrid Method Fee ($)
ALBGRAS	ALBANY_WF1	57.51	21.60	0.30	67,762	70,902
ALBGRAS	GRASMERE_WF1	43.24	13.80	0.36	50,939	49,122
ALINTA	ALINTA_PNJ_U1	667.22	143.00	0.53	786,085	638,140
ALINTA	ALINTA_PNJ_U2	545.29	143.00	0.44	642,435	566,315
ALINTA	ALINTA_WGP_GT	32.82	196.00	0.02	38,671	355,273
ALINTA	ALINTA_WGP_U2	26.68	196.00	0.02	31,429	351,651
ALINTA	ALINTA_WWF	304.62	89.10	0.39	358,887	332,158
ALINTA	BADGINGARRA_WF1	582.34	130.00	0.51	686,094	565,862
ALINTA	YANDIN_WF1	808.63	211.68	0.44	952,697	839,161
COLLGAR	INVESTEC_COLLGAR_WF1	663.21	218.50	0.35	781,364	765,183
MERREDIN	NAMKKN_MERR_SG1	0.40	92.60	0.00	477	158,952
MERSOLAR	MERSOLAR_PV1	263.63	100.00	0.30	310,598	326,696
MPOWER	AMBRISOLAR_PV1	2.12	0.96	0.25	2,502	2,896
MUMBIDA	MWF_MUMBIDA_WF1	205.20	55.00	0.43	241,757	215,146
NEWGEN	NEWGEN_KWINANA_CCG1	1,886.24	335.00	0.64	2,222,288	1,685,322
NGENEERP	NEWGEN_NEERABUP_GT1	226.38	342.00	0.08	266,713	719,533
SYNERGY	MUJA_G5	744.26	195.80	0.43	876,851	774,020
SYNERGY	MUJA_G6	731.29	193.60	0.43	861,575	762,611
SYNERGY	MUJA_G7	1,142.62	212.60	0.61	1,346,191	1,037,485
SYNERGY	MUJA_G8	1,232.00	212.60	0.66	1,451,486	1,090,132
SYNERGY	PINJAR_GT1	10.56	38.50	0.03	12,438	72,207
SYNERGY	PINJAR_GT10	52.04	118.15	0.05	61,309	233,160
SYNERGY	PINJAR_GT11	178.22	130.00	0.16	209,974	327,803
SYNERGY	PINJAR_GT2	5.97	38.50	0.02	7,036	69,506
GRIFFIN2	BW2_BLUEWATERS_G1	1,352.60	217.00	0.71	1,593,579	1,168,720
GRIFFINP	BW1_BLUEWATERS_G2	1,483.45	217.00	0.78	1,747,734	1,245,797

- Using maximum capacity for 50% of AEMO fee allocation increases cost recovery from generators with low capacity factors
- Baseload generators and high capacity factor wind generators benefit from this change

Note: Based on public SCADA generation data (not loss adjusted) and public Facility data

WEM Hybrid Method – Impact on Retailers

- IRCR and metered scheduled data by electricity retailer is confidential, so only commentary on the results is presented
- Synergy will pay more with WEM Hybrid Method because its IRCR remains fairly constant despite a high solar penetration amongst residential customers, which reduces metered consumption
- Retailers with a higher proportion of business customers will pay less under WEM Hybrid Method because their IRCR is proportionately lower when compared to residential customers

WEM Hybrid Method – Overall Impact on Market Customers

Fee Allocation to Market Participants 2021/22		
Participant	**Current Method**	**Hybrid Method**
Synergy	$18,905,324	$21,726,861
Alinta	$5,622,798	$5,438,167
Perth Energy	$2,341,089	$1,916,413
Other	$15,228,570	$12,963,018
Total	$42,097,781	$42,044,459

- Overall, Synergy incurs higher charges by moving to the WEM Hybrid approach, mainly due to use of IRCR to allocate market fees to loads and use of Maximum Capacity to allocate market fees to generators (i.e. recover higher fees from low capacity generation)
- Alinta Energy's fee allocation remains similar
- Perth Energy has a reduction due to a decrease in costs allocated to customers on basis of IRCR
- Overall reduction in AEMO fees for most other market customers

Recommendations to CARWG (27 September 2022)

- Charging generators and market customers on a 50:50 basis is consistent with causer-pays and beneficiary-pays principles
- Market Generators and market customers are all commercial entities and benefit from participation in the WEM
- Market Generators and market customers all use AEMO services
- Market fees are a cost recovery mechanism – they do not provide a price signal to either Market Generators and Market Customers (neither are they likely to be able to change their behaviour to materially reduce fees)
- No major benefit has been demonstrated to changing the fee allocation between each participant class
- Charging generators based on capacity (50%) ensures that low capacity factor generators make an adequate contribution to market service costs – no free riding on base-load generators
- AEMO costs are driven by the number of participants and number of assets, not by sent out generation
    - AEMO will spend time and resources on planning, certification, testing, scheduling and dispatch processes, settlement changes to facilitate entry of flexible generation, with low capacity factors and storage (e.g., OCGT-aero, pumped hydro and BESS)
- Charging market customers based on IRCR (50%) ensures recovery of costs from retailers with a high proportion of customers with rooftop PV
    - This reduces the inequity from recovering Market Fees based on metered consumption, which customers with rooftop PV can minimise

Recommendation to CARWG:

- Adopt the Hybrid Method to allocate Market Fees (AEMO, ERA and Coordinator costs)

Feedback from CARWG (27 September 2022)

- Regarding cost causation, it was:
  - reported that generators cause most AEMO market service costs in the WEM (to be explored further)
  - market customers/aggregators may become more of a causer in the future with the increasing penetration of DER
- There was general acceptance that allocation of Market Fees is primarily about cost recovery, with little efficiency benefits, and it was noted that equity is an important consideration
- Views on the Hybrid approach:
  - retailers with a high proportion of customers with DER (rooftop PV) would make a ‘fairer’ contribution to market service costs
  - merchant peaking generators cannot pass through Market Fees to final customers but have effectively been ‘free riding’ (paying minimal fees) to date
  - would impose implementation costs for AEMO and market participants, including contract changes (to be explored further)
- Treatment of storage was questioned – will it be treated as a generator or market customer – must ensure that it does not pay twice (to be explored further)
- Some generators expressed a general preference to allocate Market Fees only to market customers
  - some generators (Bluewaters and Shell) supported the WEM Hybrid Method as the next best alternative
  - other generators (Alinta and Collgar) supported retaining the existing cost allocation method as the next best alternative due to the likely costs to implement the WEM Hybrid approach (the CARWG is exploring these costs)
- The small-use customer representative supported the WEM Hybrid Method

Recommendation to the MAC

The MAC is to note:

- the Guiding Principles (slide 4)
- the rationale for the WEM Hybrid Method (slide 15)
- the views of the CARWG (slide 16)
- that EPWA is of the view that there will be costs to implement the WEM Hybrid Method but it will provide limited tangible benefits

The MAC is to discuss and provide views on the benefits of, and preference for either:

- further developing the WEM Hybrid Method
- retaining the Current WEM Method

(b) Allocation of Frequency Regulation Costs

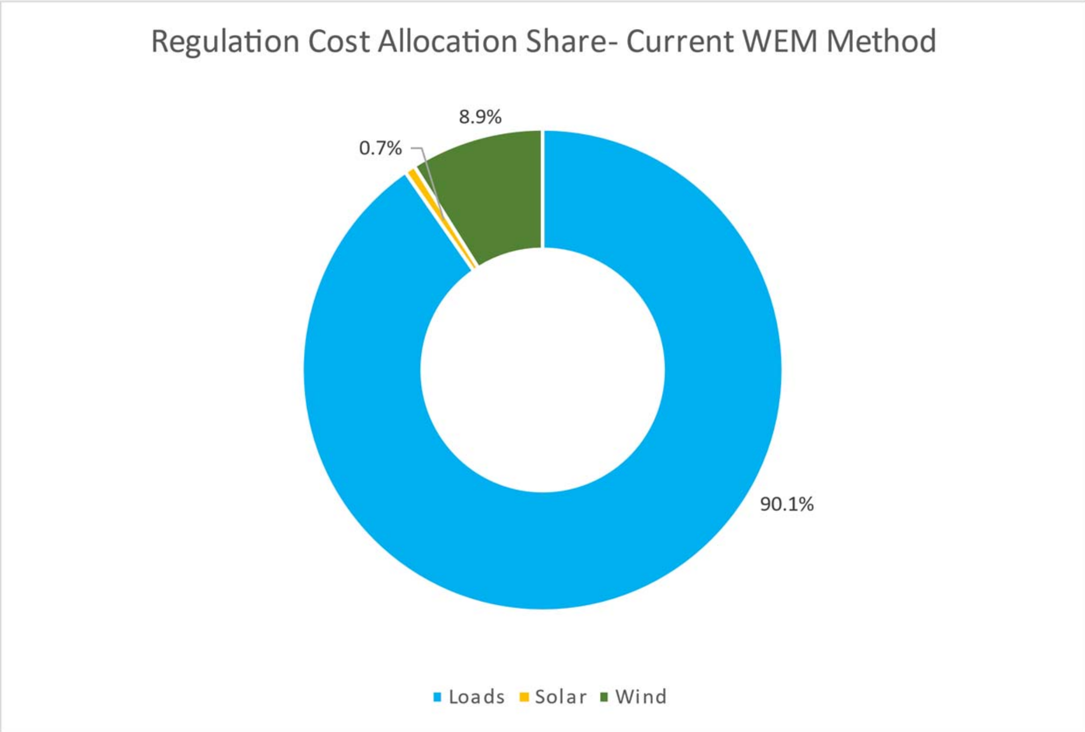
Frequency Regulation Cost Allocation

MAC supported assessing:

- the Current NEM Causer Pays Method
- a new Tolerance Method

The Current WEM Method

Frequency Cost Allocation example 27/7/2021 to 28/8/2021



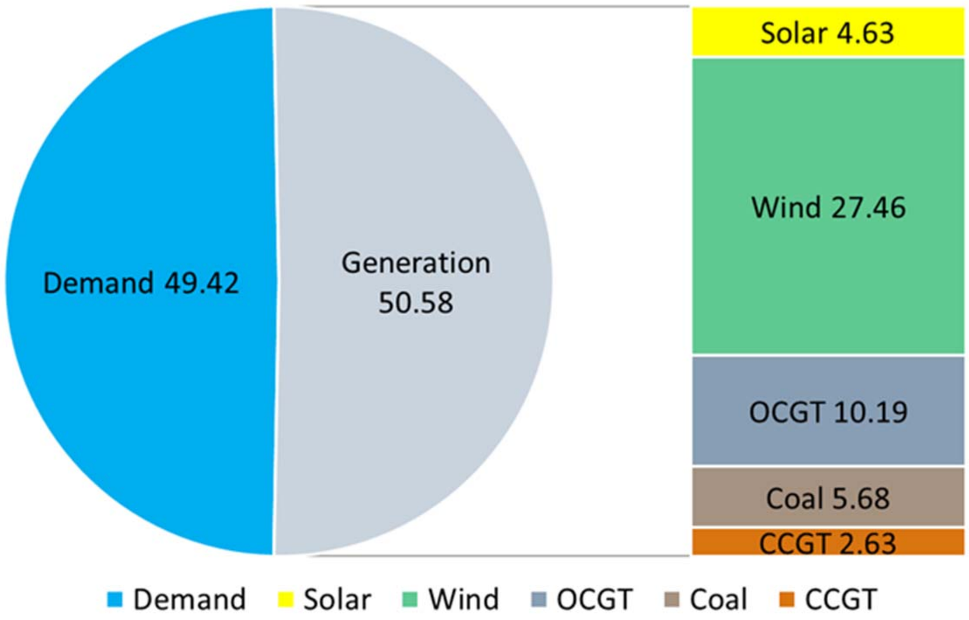
- The Current WEM Method allocates more than 90% of costs to Loads

Current NEM Causer Pays Method

Results of 100 simulations of applying the distributions to WEM generators with Average WEM 28-day load (1,376 GWh)

- Units were calculated with individual seed numbers
- For the current capacity in the WEM, the split is about even between generation and demand
- Wind accounts for the biggest pro-ration of generator costs driven by
  - Badgingarra
  - Yandin
  - Warradarge

Frequency Control Cost Recovery in the WEM – Causer Pays

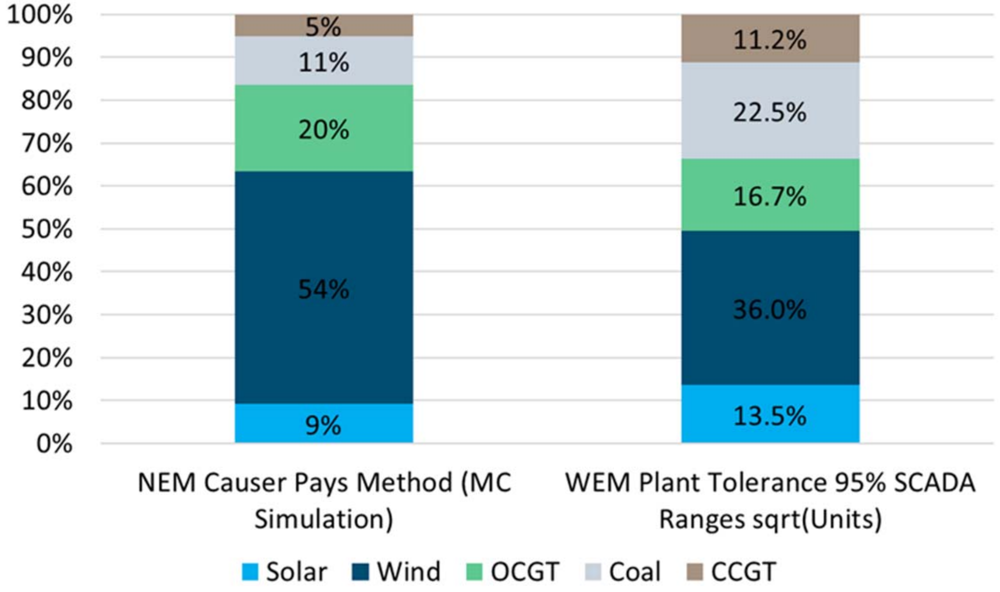


Note: numbers are % of total allocated costs for frequency regulation

The Tolerance Method

- The Tolerance Method results in higher cost recovery from solar plant and lower cost recovery from wind plant compared to the NEM Causer Pays method
- The reduction in wind and increase in solar is caused by the small number of solar PV currently in the WEM
- Less units in a technology type leads to large variance relative to installed MW

Frequency Control Cost Recovery for Generators in the NEM Causer Pays & Tolerance Method



Note: sample restricted to generators ≥ 30 MW

A New NEM Causer Pays Method

- The AEMC has approved a rule change to amend the NEM Causer Pays methodology for FCAS cost recovery to provide performance payments to Facilities that make positive contributions to improving System Frequency during a trading interval
- AEMO is currently working on how to implement the rule change
  - This rule change also significantly simplifies the NEM Causer Pays method
  - Marsden Jacob is assessing the impact of incorporating the simplifications into a new WEM Causer Pays Method

Recommendation to CARWG (27 September 2022)

- The Current NEM Causer Pays Method and Tolerance Method both attribute costs to the Facilities/Loads that impose risks and cause costs to be incurred for provision of Frequency Regulation services
- Both methods will provide incentives for participants to take actions to reduce Frequency Regulation costs (better forecasting, install storage facilities, intermittent generators providing ESS raise services, etc.)
- However, the New NEM Causer Pays Method may be preferred because
  - It is much simpler to implement than the Current NEM Causer Pays Method
  - there are benefits from a common approach for participants operating in both the NEM and WEM
  - there are cost savings for AEMO to develop and maintain processes and systems across the NEM and WEM

Recommendation to CARWG

- Consider adopting the New NEM User Pays method to allocate Frequency Regulation costs, subject to further explanation of the methodology and assessment of the impact on Market Participants

Next steps proposed to CARWG

- Marsden Jacob to analyse the impact of the proposed new NEM Causer Pays method to allocate Regulation Costs in the WEM and discuss with CARWG members

Feedback from CARWG (27 September 2022)

- General support for moving towards a ‘causer pays’ method for allocating frequency regulation costs
  - Members see the benefits of both rewarding good performance (‘the carrot’) in terms of maintaining system frequency (‘generator droop response’) and penalising poor performance (‘the stick’)
- Some concern that we should be careful in allowing parties to provide ‘too much’ good performance (e.g., parties generating more than target that happens to coincide with a low system frequency event), which could create system instability (to be considered further)
- AEMO pointed out that the WEM would not need to adopt the full proposed new NEM Causer Pays Method and should focus on what is appropriate for the WEM – there would be implementation benefits as long as what is implemented is not too dissimilar from the proposed method for the NEM

Recommendation to MAC

The MAC is to note the proposed further work in this area:

- AEMO and EPWA to arrange a detailed explanation of the new NEM Causer Pays method for CARWG members
- Marsden Jacob to assess the impact of the new NEM Causer Pays method on market participants in the WEM

(c) Allocation of Contingency Reserve Raise Costs

Contingency Reserve Raise

- Contingency Reserve Raise costs are recovered from Registered Facilities injecting >10 MW based on their cleared generation and ESS in the relevant Dispatch Interval, using a runway method
- The runway method allocates Contingency Reserve costs to causers of contingencies, commensurate with the extent to which they have contributed to the additional procurement of the Contingency Reserve Raise Requirement
- The risk for the system is the loss of an individual dispatchable generating unit and/or specific network asset that has dispatchable generating units connected to that asset
    - This becomes complicated when we have Aggregated Facilities with multiple generators and multiple connection points
- If an Aggregated Facility (none are classified as this in the WEM currently) has two generating units with separate connection points that can be dispatched separately, the runway method will allocate costs to the combined total of their sent-out generation
    - This may overestimate Contingency Reserve Raise costs (and risks) to that Aggregated Facility (the risk is associated with each independent dispatchable generating unit, not the aggregate), which may not be consistent with the causer-pays principle

Contingency Reserve Raise

- To align with the causer-pays principle, ensure that the runway method is only applied to individual dispatchable generating units – this will require changes to the definition of a Facility and Aggregated Facility
- Aggregation of Facilities by AEMO will only be approved in certain circumstances (i.e., it does not adversely impact on provision of ESS) – a requirement could be added to require the ability to accurately allocate Contingency Reserve Raise costs
- A dispatchable unit in this context refers to a unit that
  - Can adjust output in response to an instruction from System Management (this includes renewable generators that can reduce output in response to a dispatch instruction)
  - Has a set of separate coal and gas units that are independently controlled
  - Has a set of inverters that are controlled independently at a single plant
- Collgar Wind Farm was provided as an example of a plant that has two dispatchable units (not currently classified as an Aggregated Facility) – should these be treated as two dispatchable units for the purposes of allocating Contingency Reserve Raise costs?
  - Further analysis needs to be undertaken to consider both Aggregated Facilities and existing plants that have multiple dispatchable units

Feedback from CARWG (27 September 2022)

- CARWG agreed that further work is required to ensure that the runway method is only applied to 'credible' contingency events for a specific power station
  - Consideration needs to be given to treatment of Facilities with multiple units that can be operated separately and are connected separately
  - Example:
    - Collgar Wind Farm effectively comprises two independent generation units with separate network connections, so the 'credible' contingency may be that only half of Collgar will suffer a forced outage
    - Collgar's two units should be then be treated separately in the runway method
- Note that this issue is not necessarily related to the treatment of Aggregated Facilities, as per the defined term in the WEM Rules.

Recommendation to MAC

The MAC is to note the proposed further work in this area :

- EPWA is to provide further analysis and recommendations on how the runway method could be altered to ensure appropriate costs recovery from Aggregated Facilities and from power stations comprising independently dispatchable units with separate network connections

(d) Allocation of Contingency Reserve Lower Costs

Contingency Reserve Lower Requirement

- Contingency Reserve Lower is required to cover the risk of a material increase in system frequency due to a loss of single large load, or multiple loads on a single network element
- The largest credible load rejection event is 120 MW, based on the loss of the Eastern Goldfields region or the Boddington Gold Mine
- The Contingency Reserve Lower service for 2021-22 remains up to a maximum of 90 MW, which is 120 MW (largest continency event) minus 30 MW for Load Relief (loads draw more power when system frequency is high)
- The potential introduction of a large-scale BESS into the SWIS (i.e., 250 MW) would more than double the largest credible load rejection contingency – this could increase the Contingency Reserve Lower service to 220 MW (i.e., 250 MW – 30 MW Load Relief)

Current Cost Allocation Method

With 250 MW BESS entering the SWIS

Cost Recovery in a Trading Interval Under Current Method for LRR

Based on 2021-22 LRR Costs			
Requirement (MW)	220	Interval Cost ($)	Cost Allocation (%)
Unit Cost ($MW per Interval)	3.61	794.91	
Large Battery (MW)	250	103.50	11.52%
Large Load (MW)	120	49.68	5.53%
Small Load (MW)	1800	745.23	82.95%
Total Load (MW)	2170	898.42	100.00%

Notes:

- Small Load is effectively equal to the notional wholesale meter
- Assuming large Load is a Non-Dispatchable Load equipped with an interval meter

- It is currently proposed that Contingency Reserve Lower costs will be recovered from Loads based on their share of consumption in the trading interval
- This is consistent with the current cost allocation method for Load Rejection Reserve

Cost Reflective Approach to Contingency Reserve Lower

Cost Recovery in a Trading Interval under an Alternative Runway Method

Three Load Case		Tranche Cost Allocation				
Generator	Load Size (MW)	200 to 300 MW Tranche 1	120 to 200 MW Tranche 2	120 MW and below Tranche 3	Total (MW)	
Load A	250	50	80	120	250	
Load B	120	0	0	120	120	
Load C	Small Loads	0	0	1800	1800	
Tranche Amount (MW)		50	80	2040	2170	
Cost Share Interval		29%	29%	42%	100.0%	Share
Load A	250	230.5	230.5	19.6	480.7	60.5%
Load B	120	0.0	0.0	19.6	19.6	2.5%
Load C	Small Loads	0.0	0.0	294.6	294.6	37.1%
Total		230.5	230.5	333.9	794.9	100%

A. Under this revised method, BESS (Load A) bears 60% of costs in the trading interval when recharging, Small loads (37.1%) and the Non-Dispatchable Load (120 MW) only 2.5%

B. This method is more consistent with the causer-pays principle whereby the party that gives rise to additional Contingency Reserve Lower service (the BESS) pays most of the cost

C. Additional analysis required to see if this can be done without tranches (which would create boundary issues) and calculated numerically

D. Need to adjust methodology to cater for future network contingencies that may also exceed 120 MW

Recommendation to CARWG (27 September 2022)

- 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 how the largest generator is the main causer of the requirement for Contingency Reserve Raise service
- A causer-pays approach consistent with the method used for Contingency Reserve Raise suggests that a modified ‘runway method’ could be applied to allocate Contingency Reserve Lower costs to the largest Loads operating in a trading interval
- This will be important given current plans to build BESS of up to 250 MW in the SWIS
  - When a 250 MW BESS is operating, the Contingency Reserve Lower requirement is likely to increase to 220 MW (only 90 MW today), and most of the additional costs for this requirement should be borne by that BESS.

Question posed to CARWG (27 Sept 2022)

- Does the CARWG support exploring allocating Contingency Reserve Lower costs using a runway approach?

Next steps proposed to CARWG (27 Sept 2022)

- MJA to develop a runway method that could be applied to Contingency Reserve Lower costs and analyse the impact of this method on Market Participants

Feedback from CARWG (27 September 2022)

- Given the likely entry of BESS that could exceed 120 MW in the future, adopting a modified runway method to allocate Contingency Reserve Lower costs is appropriate
    - This may become the major 'risk' factor in the future
- The CARWG noted that:
    - Network outages and the loss of major loads (i.e., 30 MW) are not likely to be the major causer of costs in the future
    - When BESS or large Facilities exceeding 120 MW are not operating, then allocating costs under current method is appropriate (recovered from Loads based on their share of consumption in the Trading Interval).
- The CARWG agreed that consideration should be given to applying the runway method to facilities above 120 MW for Contingency Reserve Lower services

Recommendation to MAC

The MAC is asked to support:

- EPWA to further develop and assess a modified runway method for Contingency Reserve Lower cost allocation in the WEM

(e) Allocation Other ESS costs

RoCoF Control (Inertia)

- While generators, network facilities and large customers are not the causers of low inertia, they will benefit from improved ride-through capability (i.e., equipment that can cope with sudden variations in system frequency)
- Generators, network facilities and large customers should be incentivised to install equipment with ride-through capability via RoCoF Control charges
- Attributing costs to generators, Loads and Western Power is consistent with the causer- and beneficiary-pays principles
- Cost attribution levels should be determined on the basis of the benefit that each party receives from improving ride-through capability of equipment.

Recommendation to CARWG (not discussed on 27 September 2022)

- There is no need to change the current cost allocation method for RoCoF services

System Restart Service

- The requirement for System Restart Service (Black Start) is not driven by the actions of Market Participants, so it would be difficult to attribute system wide failures and the requirement for System Restart Service to any one participant or group of participants (identifying causers)
- System Restart Service pricing is primarily focused on recovery of costs from beneficiaries, so the cost of System Restart Service should be borne by Loads

Recommendation to CARWG (not discussed on 27 September 2022)

- Cost recovery from market customers only and using billing attributes that are consistent with cost recovery of Market Services costs

NCESS (Voltage Control and 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 of such services are Loads requiring power to be supplied and generators providing the power, including any transmission issues that require such services
  - These services are often provided under network support contracts with the network operator, which may be a substitute for network investments
- It is appropriate to recover these costs from Loads (beneficiaries), given that the focus of this charge is typically cost recovery, not market efficiency
- As these services may be a substitute for network investments, it may also be appropriate for network operators to recover these costs via network access charges

Recommendation to CARWG (not discussed on 27 September 2022)

- if Western Power procures the NCESS, the cost should be recovered via network tariffs
- if AEMO procures the NCESS, the costs should be recovered from market customers and use billing attributes that are consistent with cost recovery of Market Services costs

Next Steps

Next Steps

- CARWG to meet on 25 October to:
  - have AEMO provide an overview of the New NEM Causer Pays Method for allocating Frequency Regulation costs; and
  - Marsden Jacob provide analysis of the impact of this method in the WEM
- Provide progress report to the MAC by 8 November for discussion at the 15 November 2022 MAC meeting
- Develop cost allocation methodologies, accounting for feedback from the CARWG and MAC
- Draft consultation paper
  - Draft paper to MAC on 6 December 2022 for discussion at MAC meeting on 13 December 2022
  - Publish for consultation in December 2022 / February 2023

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

Agenda Item 7(a): Overview of Rule Change Proposals (as of 4 October 2022)

Market Advisory Committee (**MAC**) Meeting 2022_10_11

- 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 Proposal

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						
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

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
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 B will commence on 01/03/2023
2021/212	17/12/2021	Wholesale Electricity Market Amendment (Tranche 5 Amendments) Rules 2021	• 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 G will commence at times specified by the Minister in notices published in the Gazette.
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.
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 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: o 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.

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

Agenda Item 8: Future Reviews

Market Advisory Committee (**MAC**) Meeting 2022_10_11

1. Purpose

To provide draft Scopes of Work for the MAC to consider for two potential reviews under the Wholesale Electricity Market (**WEM**) Rules and to seek advice from the MAC on the priority and timing for the reviews.

2. Recommendation

That the MAC:

- reviews and provides comments on the draft Scopes of Works for:
  - the review of the Procedure Change Process (**Attachment 1**); and
  - the review of the Participation of Demand Side Response in the WEM (**Attachment 2**);
- advise on:
  - the respective priority of these potential reviews; and
  - the preferred timing for commencing these potential reviews and when any rule changes resulting from the reviews should be implemented.

3. Background

Review of the Procedure Change Process:

In its discussion of the MAC Forwards Work Program, the MAC agreed that the Coordinator should consider undertaking a review of the Procedure Change Process (see Table 1 in Agenda Item 5). Therefore, Energy Policy WA has developed a draft Scope of Works for a potential review of the Procedure Change Process for consideration by the MAC.

Review of the Participation of Demand Side Response in the WEM:

Based on comments provided by Market Participants, including during the Reserve Capacity Mechanism Review process, Energy Policy WA has identified that there may be a need to review how Demand Side Response should participate in the WEM under the WEM Rules.

The intent of this review is to ensure that Loads/Demand Side Response have adequate incentives for, and do not face any barriers to their effective participation in all of the WEM components, and are compensated appropriately for their participation (neither over- nor under-compensated).

Draft Scopes of Work:

Energy Policy WA has developed the attached draft Scopes of Work for the two potential reviews providing:

- background on why the reviews are needed;

- the scope and guiding principles for the reviews;
- the issues to be considered in each review;
- the approach to stakeholder engagement; and
- a proposed schedule for the reviews.

4. Attachments

(1) draft Scope of Works for the Review of the Procedure Change Process

(2) draft Scope of Works for the Review of the Participation of Demand Side Response in the Wholesale Electricity Market

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

Scope of Works for the Review of the Procedure Change Process

1. Introduction

1.1 Review Requirements

On 1 July 2021, the WA Government implemented a number of changes to the Wholesale Electricity Market (**WEM**) governance arrangements, including:

- abolishing the Rule Change Panel;
- transferring responsibility for administration of the rule change process and parts of the Procedure Change Process to the Coordinator of Energy (**Coordinator**); and
- changing the structure and role of the Market Advisory Committee (**MAC**).[1]

During consultation on these governance changes, Energy Policy WA identified a number of issues with the Procedure Change Process, and during discussions of its Market Development Forward Work Program in August and September 2021, the MAC agreed that a review of the Procedure Change Process should be commenced in 2021/22 to address these issues.

The Coordinator now plans to commence a review the Procedure Change Process under clause 2.2D.1(h) of the WEM Rules in 2023 and to develop any changes to the WEM Rules resulting from the review in 2023. Clause 2.2D.1(h) confers the function on the Coordinator to consider and, in consultation with the MAC, progress the evolution and development of the WEM and the WEM Rules.

1.2 Background

Clause 123 of the *Electricity Industry Act 2004* provides a head of power for the WEM Rules, and the WEM Rules provide heads of power for various WEM Procedures, which are subsidiary to the WEM Rules:

- section 2.9 of the WEM Rules places requirements on:
  - various parties to develop, publish, administer amendments to, and operate in accordance with WEM Procedures;
  - all Rule Participants to comply with WEM Procedures;
- section 2.10 specifies the Procedure Change Process; and
- section 2.11 specifies:
  - how WEM Procedures and amendments to WEM Procedures are to come into force; and

[1] These changes were implemented via the *Wholesale Electricity Market Amendment (Governance) Rules 2021*, available at https://www.wa.gov.au/government/document-collections/wholesale-electricity-market-amendment-governance-rules-2021. Further information on the consultation process for these governance changes can be found at https://www.wa.gov.au/government/publications/gazettal-of-energy-sector-governance-reforms.

- o Rule Participants' rights to request the Electricity Review Board (**ERB**) to review decisions under the Procedure Change Process.

1.2.1 The Purpose and Use of WEM Procedures

At the commencement of the WEM, the concept was that:

- the WEM Rules would cover WEM governance matters and any matter that has material policy, financial or strategic impacts on consumers or Rule Participants; and
- procedural or administrative details that may require more frequent change were put in:
  - o Power System Operation Procedures (**PSOPs**) that were applied to the System Operator[2] to address matters like short- and medium-term system planning, security and reliability, and dispatch; and
  - o Market Procedures (that were not PSOPs) that were applied to the Market Operator[3] to provide details on market operations and administrative matters.

This was done to reduce the length and complexity of the WEM Rules and so that a faster and more flexible Procedure Change Process could be put in place to govern procedural or administrative matters.

The Procedure Change Process was applied to Market Procedures and PSOPs, and the Independent Market Operator (**IMO**) was given authority to administer, and make decisions under, the Procedure Change Process because it was the subject matter expert on the procedural and administrative matters. There were fewer concerns with independence of the IMO because the Market Procedures and PSOPs only contained procedural or administrative detail, and risks from conflicts of interest were mitigated by making the IMO's decisions subject to review by the ERB.

As the WEM evolved, the Market Procedures and PSOPs were renamed to WEM Procedures, and changes were made to the parties that are responsible for developing, publishing, administering amendments to, and operating in accordance with WEM Procedures.

The WEM Rules now separately address the requirements on these parties, but for simplicity, they are collectively referred to in this document as '**Procedure Administrators**'. The current Procedure Administrators are:

- AEMO;
- the Economic Regulation Authority (**ERA**);
- the Coordinator; and
- Network Operators (currently only Western Power).

The Procedure Change Process in the WEM Rules has evolved to reflect changes to the Procedure Administrators.

Further, as part of the significant changes to the WEM that were developed and are being implemented via the Energy Transformation Strategy, heads of power have been included in the WEM Rules for various new WEM Procedures that include matters beyond procedural or administrative detail.

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2 System Management, a ring-fenced entity within Western Power, was the System Operator at the commencement of the WEM.

3 The Independent Market Operator (**IMO**) was the Market Operator at the commencement of the WEM.

This shift in the purpose and use of WEM Procedures raises potential governance issues, including the adequacy of the relevant consultation processes and the potential for conflicts of interest for Procedure Administrators.

The review of the Procedure Change Process will need to consider how to address these governance matters, including:

- how to determine whether a matter should be addressed in the WEM Rules or the WEM Procedures;
- who should be able to propose changes to the WEM Procedures, and what process should be followed once such changes are proposed by third parties;
- what consultation should be undertaken on Procedure Change Proposals;
- are the criteria and timeframes for decisions on Procedure Change Proposals appropriate; and
- what level of guidance needs to be in the WEM Rules on the form and content of WEM Procedures.

1.2.2 Previous Amendments to the Procedure Change Process

The Procedure Change Process has been amended on numerous occasions by the IMO, the Minister and the Rule Change Panel. At a high-level, the Procedure Change Process has evolved as follows:

- initially, the Market Procedures and PSOPs governed market operations by the IMO and system operations by System Management, respectively;
- the IMO's market operation function was transferred to AEMO, including the functions of operating under and making amendments to Market Procedures;
- the System Management role was transferred from the ring-fenced entity within Western Power to AEMO, including the functions of operation under and making amendments to PSOPs;
- the IMO's compliance function was transferred to the ERA, including the development of, amendment to, publication of and operating under certain Market Procedures;
- the Rule Change Panel was made responsible for the rule change process, including the development of, amendment to, publication of and operating under certain Market Procedures;
- Western Power was made responsible for the development of, amendment to, publication of and operating under several WEM Procedures;
- the Coordinator was made responsible for the development of, amendment to, publication of and operating under several WEM Procedures;
- the ERB was given authority to review the Coordinator's decisions on Procedure Change Proposals;
- clauses 2.10.10 (the requirement to prepare a Procedure Change Report) and 2.10.13 (the required content for Procedure Change Reports) were applied to all Procedure Administrators;
- the Rule Change Panel's functions and responsibilities were transferred to the Coordinator, including the Panel's responsibilities under the Procedure Change Process;
- the role of the independent Chair of the MAC was created, which includes responsibilities relating to the Procedure Change Process;
- the reasons allowed for extensions to timeframes of Procedure Change Processes were amended; and

- timeframes and terminology in the process were amended, including that references to 'System Management' were replaced with 'AEMO' and references to 'Market Procedures' and 'PSOPs' were replaced with 'WEM Procedures'.

1.2.3 Current WEM Procedures

The WEM Rules provide a head of power for numerous WEM Procedures, including:

- X WEM Procedures are currently published on AEMO's website,[4] including:
    - X relating to administrative matters;
    - X relating to Distributed Energy Resources;
    - X relating to market operations;
    - X relating to dispatch and planning;
    - X relating to the Reserve Capacity Mechanism;
- X WEM Procedures are currently published on the Coordinator's Website;[5]
- X WEM Procedures are currently published on the ERA's website;[6] and
- X WEM Procedures are currently published on Western Power's website.[7]

1.2.4 Issues Identified with the Procedure Change Process during the Energy Transformation Strategy process

During consultation on the governance changes that were implemented on 1 July 2021, stakeholders raised several concerns with the Procedure Change Process, including:

- it is not clear what triggers the commencement of a Procedure Change Process (i.e. what happens after a third party proposes a change to an existing procedure or a new procedure, or when a Procedure Administrator drafts a Procedure Change Proposal);
- there is no timeline specified for Procedure Administrators to draft and commence Procedure Change Proposals (i.e. it appears that the Procedure Change Process does not commence until the Procedure Administrator publishes the proposal and the timing for publication is at the discretion of the Procedure Administrators);
- it is unclear when Procedure Change Reports must be published, or when and where extension notices must be published; and
- there is no process for Procedure Administrators to extend the timeframe for their decision on whether a Procedure Change Proposal is required.

4 https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/procedures.

5 https://www.wa.gov.au/government/document-collections/wem-procedures.

6 https://www.erawa.com.au/electricity/wholesale-electricity-market/market-procedures.

7 <insert link>.

2. Project Scope

2.1 Objective

The objective for the Procedure Change Process Review is to review the Procedure Change Process and develop a process that:

(1) is fit for purpose given the changes to the nature and content of WEM Procedures and the change to the Procedure Administrators;

(2) is simple, clear and consistent for all Procedure Administrators; and

(3) has a prescribed timeframe and a clear criteria for decisions on Procedure Change Proposals.

2.2 Guiding Principles

The guiding principles for the Procedure Change Process Review are that the Procedure Change Process should:

(1) Meet the Wholesale Market Objectives.

(2) Be cost-effective, timely, simple, predictable, consistent, flexible, and transparent.

(3) Ensure stakeholders have an appropriate opportunity to provide input into Procedure Change Proposals, including appropriate consultation processes and independent review of decisions.

(4) Provide clear and appropriate timeframe and criteria for the decision-makers in the Procedure Change Process.

(5) Provide clear and appropriate criteria for when a matter should be addressed in the WEM Rules or the WEM Procedures.

2.3 Issues to be Considered

Issues that are to be considered in the review include:

(1) Should changes be made to who can initiate a Procedure Change Proposal?

(2) Should explicit criteria be specified that the decision-maker must have regard to in approving amendments to WEM Procedures and, if so, what should they be (similar to the decision criteria for Rule Change Proposals)?

(3) Are the requirements for submitting Procedure Change Proposals sufficient and clear?

(4) Are the timelines for commencing and progressing Procedure Change Proposals prescribed in the WEM Rules appropriate, sufficient and clear?

(5) Is the role of the MAC in reviewing Procedure Change Proposals appropriate?

(6) Is the required content for Procedure Change Reports sufficient and clear?

(7) What are the criteria for determining whether a matter should be addressed in the WEM Rules or the WEM Procedures, and should any of the current WEM Procedures be moved to the WEM Rules, or vice versa?

(8) What level of guidance needs to be in the WEM Rules on the form and content of WEM Procedures?

(9) Should the requirement to publish a list and description of each Procedure apply to all Procedure Administrators?

Any additional issues will be identified in consultation with the Procedure Administrators and other stakeholders.

3. Stakeholder Engagement

Under clause 2.5.1C of the WEM Rules, the Coordinator must consult with the MAC before commencing the development of a Rule Change Proposal.

Energy Policy WA will undertake the Procedure Change Process Review and develop straw man proposals for changes to the Procedure Change Process in consultation with:

- the Procedure Administrators, likely through one to one discussions;
- the MAC, likely through a MAC Working Group; and
- other stakeholders through consultation papers.

4. Project Schedule

The following is a preliminary high-level project schedule for the Procedure Change Process Review.

Tasks/Milestones	Timing
Consult with the MAC on the scope of works for the Procedure Change Process Review	October 2022
Engage a consultant to assist with the review	1 month
Form a MAC Working Group	
Consult with Procedure Administrators and the MAC/MAC Working Group on the requirements for the Procedure Change Process	2 months
Develop and publish a Consultation Paper on the high-level design for the Procedure Change Process and seek stakeholder comments	2 months
Develop the detailed design for the Procedure Change Process, in consultation with the Procedure Administrators and the MAC/MAC Working Group	2 months
Develop and publish a Consultation Paper on the detailed design for the Procedure Change Process and seek stakeholder comments	1 month
Submissions on the Consultation Paper	1 month
Develop and publish an Information Paper on the revised Procedure Change Process and relevant draft WEM Amending Rules	1 month
Finalise one or more Rule Change Proposals for consideration and approval by the Coordinator and the Minister	1 month
Commencement of rule changes	TBD

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

Scope of Work for the Review of the Participation of Demand Side Response in the Wholesale Electricity Market

1. Introduction

The Coordinator of Energy (**Coordinator**) intends to review the rules for participation of Demand Side Response in the Wholesale Electricity Market (**WEM**) under clause 2.2D.1 of the WEM Rules. Clause 2.2D.1(h) confers the function on the Coordinator to consider and, in consultation with the Market Advisory Committee (**MAC**), progress the evolution and development of the WEM and the WEM Rules.

The Coordinator considers that Loads/Demand Side Response will play an important role in the future of the WEM because of:

- the changes to the nature of the demand profile and generation in the SWIS since the market start; and
- the transition to a low emissions energy system characterised by increasing levels of intermittent and distributed generation.

Therefore, it is important to ensure that there are no barriers to the participation of Loads/Demand Side Response in all of the WEM components.

The purpose of this review is to ensure that Loads have adequate incentives to participate in the WEM, and are compensated appropriately for the provision of their services (neither over- nor under-compensated). The importance of Demand Side Response as a flexibility/firming resource in the WEM has also been highlighted during the Reserve Capacity Mechanism (**RCM**) Review scenario modelling work.

1.1 Current Participation of Loads in the WEM

Currently the direct participation of Loads in the WEM is limited to their participation as a:

- Demand Side Programme (**DSP**) or part of a DSP in the RCM; and
- Interruptible Load.

Loads also participate indirectly in the WEM as they:

- pay for the consumption of energy either through bilateral contracts or the Balancing Market; and
- pay for the RCM based on their Individual Reserve Capacity Requirement (**IRCR**).

While Loads will be able to register as Scheduled Facilities in the New WEM to provide other market services, analysis of the WEM Rules must be undertaken to ensure that they can provide services and extract value in all of the WEM components simultaneously, in the same way as other Scheduled Facilities.

1.2 Related Reviews

The Coordinator is currently undertaking a review of the RCM that may affect this review of participation of Loads in the WEM. Energy Policy WA's system stress analysis for stage 1 of the RCM Review indicated that Demand Side Response will be important for system reliability in all of the future modelled scenarios.

While Stage 2 of the RCM Review will consider the treatment of DSPs and IRCR, the RCM Review is not going to examine the participation of Demand Side Response across all of the WEM components.

The Coordinator is currently also undertaking the following projects that may impact the participation of Loads/Demand Side Response in the WEM:

- SWIS Demand Assessment;
- Sectoral Emissions Reduction Scheme;
- DER Roadmap; and
- the Low Load Project.

1.3 Participation of Loads in the New WEM

The new WEM is planned to commence on 1 October 2023. In theory, Loads will be allowed to participate in most aspects of the new WEM as long as they meet the relevant requirements.

The relevant WEM Rules that are expected to be in place for the new WEM include:

- Section 2.29 of the WEM Rules sets out the rules for registering facilities in the WEM. At a high level, the registration and participation framework for Loads sets out:

  A Load (defined as one or more electricity consuming resources or devices, other than Electric Storage Resources, located behind a single network connection point or electrically connected behind two or more shared network connection points) is a Facility Technology Type (clause 2.29.1).

- The Facility Classes relevant to Loads are (clause 2.29.1A):
  - Scheduled Facility;
  - Semi-Scheduled Facility;
  - Non-Scheduled Facility;
  - Interruptible Load; and
  - Demand Side Programme.
- The following are Facilities that are relevant for Loads for the purposes of the WEM Rules (clause 2.29.1B):
  - a Small Aggregation;
  - a Demand Side Programme; or
  - an Interruptible Load.

1.4 Benefits that Loads can provide in the WEM

Energy Policy WA considers that loads can contribute by**:**

- participating as a Scheduled Facility in the Real Time Market;

- reducing consumption during system peak (i.e. by being part of a DSP in the RCM);
- shifting consumption from system peak to times of low load; and
- adjusting consumption to provide Essential System Services (**ESS**).

Different types of Loads have different characteristics that affect the benefit that they can provide to the system. The relevant characteristics include:

- how quickly and reliable a Load can respond to instructions;
- how long the Load can respond in a single instance;
- how frequently the Load response can be deployed over a period;
- whether there are any seasonal or time-of-day restrictions on use of the Load;
- the cost that the Load incurs for its response; and
- the impact on overall system demand, including by:
  - Load reduction (virtual generation);[1] and
  - Load shifting (storage/virtual storage).[2]

1.5 Future Changes in Load Technologies

As the energy system evolves, new sources of load flexibility are expected to emerge, including:[3]

- electrolysis for large-scale hydrogen production;
- electrification of metals and minerals processing;
- smart controls for commercial buildings;
- electric vehicles;
- behind the meter solar and battery storage; and
- orchestrated energy consumption devices.

2. Project Scope

The objective of this review is to:

- identify the different ways Loads/Demand Side Response can participate across the different WEM components;
- identify and remove any disincentives or barriers Loads / Demand Side Response participating across all of the different WEM components; and
- identify any potential for over- or under-compensation of Loads/Demand Side Response (including as part of "hybrid" facilities") as a result of their participation in the various market mechanisms.

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1 Where a load reduction is not compensated by an increase in demand at another time (e.g., if a customer sets their air conditioning at a warmer temperature during peak periods on a hot day, this would result in an absolute reduction in system demand).

2 Some sources of flexibility must be compensated by an increase in demand at another time (e.g., if a customer pre-cools their building to avoid using the air conditioning during peak periods on a hot day, then this would not decrease the total system demand over the day, and may increase demand over the course of the day to account for inefficiency in pre-cooling relative to cooling when it is needed [i.e. the building is not perfectly insulated]). Like physical batteries, this type of load flexibility shifts energy use.

3 https://arena.gov.au/assets/2022/02/valuing-load-flexibility-in-the-nem.pdf

The following aspects related to the participation of Loads are out of scope for this review:

- certification and dispatch baseline for DSPs; and
- treatment of IRCR.

2.1 Guiding principles

The guiding principles for the review of the participation of Loads in the WEM are that any recommendations should:

(1) Meet the Wholesale Market Objectives.

(2) Enable the orderly transition to a low greenhouse gas emissions energy system.

(3) Be cost-effective, simple, flexible and sustainable.

(4) Allocate risks to those who can manage them best.

(5) Provide investment signals and technical capability signals that support the reliable and secure operation of the power system.

(6) Ensure that the value of Demand Side Response can be maximised for the benefit of those who provide it and the WEM as a whole.

(7) Ensure that Loads are not under- or over-compensated for their participation and treatment in any of the WEM components.

2.2 Project stages

The review of the treatment of Loads in the WEM is planned to comprise the following elements.

Step 1: High level assessment of the participation of Loads/Demand Side Response across all WEM components based on:

- o A review of the participation of Loads/Demand Side Response in other markets in the context of what problems their electricity systems are facing or are expected to face in the future, and whether/how these arrangements relate to the WEM. Jurisdictions to be investigated include:
  - NEM;
  - UK;
  - PJM; and
  - any other jurisdictions identified by the MAC or Energy Policy WA.
- o The outcome of the system stress analysis from stage 1 of the RCM Review.

Step 2: A gap analysis identifying any barriers and disincentives for Loads to participate across all components of the WEM and provide the services identified under Step 1, including in:

- o the registration framework;
- o the Real Time Market;
- o the ESS market, including Non-Co-Optimised ESS; and
- o the RCM.

Step 3: Formulations of recommendations for further action, if any, and development of Rule changes, if necessary.

3. Stakeholder Engagement

The review of the participation of Loads in the WEM will be undertaken in close consultation with the MAC, either directly through MAC meetings or, more likely, through the establishment of a Working Group. Participation in such a Working Group would not be limited to MAC members.

Energy Policy WA will develop consultation papers based on the outcomes from the Working Group and/or MAC meetings and invite feedback from all stakeholders.

Under clause 2.5.1C of the WEM Rules, the Coordinator must consult with the MAC before commencing the development of a Rule Change Proposal.

4. Project Schedule

The following is a preliminary high-level project schedule for this.

Tasks/Milestones	Timing
Consult with the MAC on the Scope of Works for the Demand Side Response Participation Review and timing for commencement of the review	October 2022
Engage a consultant(s) to assist with the review	1 month
Establish a MAC Working Group	
Initial MAC Working Group meeting	TBA
Step 1	
Literature review of the participation of Loads/Demand Side Response in other jurisdictions	2 month
Assessment of the relevance of the jurisdictional review to the WEM in consultation with the MAC/MAC Working Group	
Step 2	
Gap analysis in consultation with the MAC/MAC Working Group	2 months
Step 3	
Formulation of recommendations for further actions in consultation with the MAC/MAC Working Group	2 month
Develop and publish a Consultation paper regarding the recommendations	1 month
Submissions on the Consultation Paper	1 month
Develop and publish an Information Paper on the changes to the participation of Loads in the WEM, and proposed Amending Rules for stakeholder consultation	2 months
Stakeholder Consultation on the proposed Amending Rules	1 Month
Submit any necessary Rule Change Proposals for consideration and approval by the Coordinator and the Minister	1 month
Commencement of rule changes	TBD