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

Meeting Agenda

Meeting Title:	Reserve Capacity Mechanism Review Working Group (**RCMRWG**)
Meeting Number:	2022_10_13
Date:	Thursday 13 October 2022
Time:	9:00 AM to 11:30 AM
Location:	Online, via TEAMS.

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda	Chair	Noting	5 min
2	Meeting Apologies/Attendance	Chair	Noting	2 min
3	**(a)** Minutes of meeting 2022_07_14	Chair	Noting	2 min
	(b) Minutes of meeting 2022_07_21	Chair	Noting	2 min
4	Action Items	Chair	Discussion	2 min
5	Purpose of this session	RBP	Discussion	2 min
6	Policy statement principles	RBP	Discussion	15 min
7	Policy implementation options	RBP	Discussion	45 min
8	Common elements	RBP	Discussion	35 min
9	Options for distributing support payments	RBP	Discussion	30 min
10	Next Steps	Chair	Discussion	5 min
11	General Business	Chair	Discussion	5 min
	Next Meeting: 24 November 2022			

Please note this meeting will be recorded.

Government of **Western Australia**
Energy Policy WA

Minutes

Meeting Title:	Reserve Capacity Mechanism Review Working Group (**RCMRWG**)
Date:	14 July 2022
Time:	9:30am – 11:30am
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	From 9:45am
Rhiannon Bedola	Synergy	
Manus Higgins	AEMO	
Toby Price	AEMO	
Jacinda Papps	Alinta Energy	
Peter Huxtable	Water Corporation	
Paul Arias	Bluewaters Power	
Mark McKinnon	Western Power	From 10:15am
Patrick Peake	Perth Energy	
Matt Shahnazari	Economic Regulation Authority	
Richard Cheng	Economic Regulation Authority	
Noel Schubert	Small-Use Consumer representative	
Andrew Stevens	Consultant	
Rebecca White	Collgar Wind Farm	
Wendy Ng	Shell Energy	
Richard Bowmaker	Robinson Bowmaker Paul (**RBP**)	
Ajith Sreenivasan	RBP	
Tim Robinson	RBP	
Stephen Eliot	Energy Policy WA (**EPWA**)	
Laura Koziol	EPWA	
Shelley Worthington	EPWA	

Apologies	From	Comment
Dev Tayal	Tesla Energy	
Andrew Walker	South32 (Worsley Alumina)	

Apologies	From	Comment
Dale Waterson	Merredin Energy	

Item	Subject	Action
1	**Welcome** Ms Koziol opened the meeting at 9:30am.	
2	**Meeting Apologies/Attendance** Ms Koziol noted the attendance as listed above.	
3	**Minutes of RCMRWG meeting 2022_06_16** Draft minutes of the RCMRWG meeting held on 16 June 2022 were distributed on 7 July 2022. The RCMRWG accepted the minutes as a true and accurate record of the meeting. Mr Shahnazari noted that the RCMRWG seemed to form a view at its meeting on 7 July 2022 that the Reserve Margin is to account for the largest contingency on the system. Mr Shahnazari expressed the view that this might lead to double counting and that the Reserve Margin is instead intended to account for uncertainty in forecasting 10% POE of peak demand. **Action: RCMRWG Secretariat to publish the minutes of the 16 June 2022 RCMRWG meeting on the RCMRWG web page as final.**	**RCMRWG Secretariat**
4	**Action Items** The paper was taken as read.	
	The slides for agenda items 5 to 9 are available on the webpage for the RCM Review (https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group).	
5	**Project Timeline** Mr Robinson presented the timeline and noted that an additional RCRMRWG meeting was scheduled for 21 July 2022 to discuss CRC allocation and that the next step is publication of the consultation paper.	
6	**BRCP for the Peak Capacity Product** Mr Robinson led discussion on the Benchmark Reserve Capacity Price (**BRCP**) for the peak capacity product (slides 7 to 12). The following issues were discussed: • Mr Robinson recapped how the current BRCP is set and asked whether the assumptions for this calculation still hold. • Mr Robinson suggested that the WEM Rules should provide guidance on setting the BRCP and that details can be left to a WEM Procedure. • Mr Robinson noted that we need to make sure that revenue streams are available so that the most efficient marginal new entry facility can recover its efficient short run costs in the energy and	

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	Essential System Services (**ESS**) markets and efficient capital costs from the Capacity Mechanism. • Ms Bedola asked how we can ensure that an efficient marginal energy provider can recover its fixed costs. ○ Mr Robinson noted that any facility that has lower short-run costs than the marginal energy provider will recover some fixed costs from the energy and ESS markets, and that we are seeing investment in renewables even though they have higher capital costs than a 160 MW OCGT – they do not recover all of their capital costs from the Capacity Mechanism and recover some through the energy and ESS markets. ○ Ms Guzeleva noted that renewables also currently get a subsidy. ○ Ms Bedola asked about mid-merit plants. Mr Robinson suggested that the question is how mid-merit units will cover their fixed costs in 10 years' time, when the peakers that are currently marginal are no longer providing infra-marginal rents. Mr Robinson suggested that we should not write rules to guarantee that existing plants, which have been in place for some time, can recover their fixed costs. ○ Ms Guzeleva noted that these units will be needed in the ESS market between now and 2030, when longer duration storage comes on, and that the economic modelling will consider this in the medium term. ○ Mr Robinson confirmed that the economic modelling will look at whether there are cases where a plant will exit the market or a new entrant of the type we need cannot enter the market because it cannot recover its fixed costs from capacity and energy revenue. • Ms White suggested that we cannot create a market where a generator can only recover its costs if it participates in the ESS market, this would be contrary to the concept of recovering capital costs from the RCM and operating costs from the real time markets. ○ Ms Guzeleva indicated that ESS is a real time market and that it is expected that the market will shift away from energy to ESS for devices that are capable of providing ESS. ○ Ms White suggested that each real time market needs to be considered individually – if you are operating in the energy market, you should be able to recover your variable costs from that energy market and should not have to also participate in another real time market to cover variable costs. ○ Mr Stevens asked if the energy market price caps would be made higher if the BRCP is lowered. ▪ Mr Robinson clarified that energy price caps in the WEM are set low to reflect the existence of the RCM, but are	

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	higher in the NEM, so that participants will sometimes recover more than their short-run costs, even if they are marginal. We need to be aware of the energy price caps when thinking about how facilities can recover various categories of cost. ▪ Mr Stevens pointed out that investment decisions are based on whether a facility can recover its capex against the 160 MW OCGT baseline and what can be recovered in the energy market – there is a relationship between the BRCP and energy price caps and we would ruin the market if the capacity price is set extremely low and the energy price caps do not move to let in participants. Slides 10 and 11 were used to discuss the reference technology for the BRCP (*note: the slides that were presented were updated from those that were distributed to the RCMRWG and the updated slides are now published on the RCMRWG webpage*). • Mr Robinson presented the expected capital costs ($/kW) for various types of technology based on the central and high VRE scenarios from the CSIRO generation cost report. ○ In the central VRE central scenario, the cost for a four hour battery is already lower than a small OCGT but it will be higher than for a large OCGT for some time. ○ In the high VRE scenario, the cost of a four hour battery is below even than the large OCGT in 2024, and an eight hour battery will be below the cost of a large OCGT by 2030. ○ This indicates that batteries are competitive against small OCGTs but it will be some time before they are competitive against large OCGTs. • Mr Robinson indicated that consideration needs to be given to whether an OCGT could credibly be built in the SWIS in the next 5-10 years, noting that none are currently being considered and considering both cost and other aspects, like Government policy (recognizing that Government policy does not prevent building OCGTs). • Mr Robinson noted that a 4 hour battery will currently meet the needs of the SWIS, but we will need 8 hour storage by the 2030s and 16 hours by 2050 to cover the duration gap. ○ Mr Robinson showed a comparison of the costs over time for small and large OCGTs and for 4, 8 and 16 hour batteries, based on CSIRO data. Mr Robinson indicated that, as the type of battery required in the SWIS shifts over time, the cost of batteries may be above or below the cost of a small OCGT, but will likely be higher than the cost of a large OCGT. ○ Mr Robinson indicated that the WEM Rules do not provide guidance on how to set the BRCP and the proposal is to specify that the BRCP should represent the per MW capex cost	

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	of the new entrant technology with the lowest expected capital, and that the ERA's regular BRCP reviews should determine the reference technology. ○ Mr Robinson indicated that choosing a higher cost reference technology, while a cheaper technology can be built, would give facilities more contribution to their capital costs through the capacity mechanism than is needed. ○ Ms White indicated that the Minister has alluded to Synergy needing to build another gas turbine given the coal plant retirements. Ms Guzeleva indicated that the Minister's statement was that Synergy would not build more gas turbines. ○ In response to a question from Mr Schubert, Mr Robinson indicated that pumped hydro unit costs are higher than batteries. ○ Mrs Papps indicated that the current BRCP methodology assumes a 160 MW liquid fueled OCGT and asked if this is still the assumption. ▪ Mr Robinson indicated that a big OCGT would need to be 300 MW or more achieve the lower capital costs. ▪ Mr Robinson asked for feedback on whether it was likely that a liquid fueled OCGT was feasible in WA. ▪ Ms Guzeleva indicated that a consultation paper on the market power mitigation review will be published by the end of July 2022 that will propose a single energy cap that will cover the highest marginal cost in the market, which is currently diesel based. • Mr Shahnazari noted that it will be important to consider revenues from participation in other parts of the market when setting the BRCP. • In response to a question from Ms White, Mr Robinson indicated that we will need two BRCPs – one for the peak capacity product and one for the flexibility capacity product, and the same considerations will apply to setting the two BRCPs. • Mr Higgins asked for stakeholder feedback on whether they are experiencing difficulties in securing liquid fuel contracts that can meet the 14 hour fuel requirement for small units? Mrs Papps indicated that she could respond on this separately. • Regarding use of gross or net cost of new entry (**CONE**) in determining the BRCP, Mr Robinson noted that: ○ the intent is to set the energy price cap so that the highest cost facility in the fleet can recover its short-run costs in the energy market but would not get a contribution to its capital costs; ○ if an OCGT is the marginal new entrant and is the most expensive provider of energy, then we can rely on gross CONE to set the BRCP; but	

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	○ if the marginal provider of capacity no longer has the highest short-run costs in the fleet, then that facility will start getting an additional contribution to its long-run costs from the energy market. • Mr Robinson proposed that: ○ to simplify the calculations, the rules should specify that the BRCP should be based on gross CONE, so long the marginal capacity provider is also the highest cost energy provider; but ○ otherwise the rules should prescribe the use net CONE. So we would need to start using net CONE to set the BRCP if batteries become the marginal technology. • Ms Guzeleva pointed out that, apart from the highest short-run marginal cost (**SRMC**) facility, as longs as the price cap is high enough for a facility to recover its SRMC, then it will get a contribution to its capital costs when it runs, in which case there should be no concerns on viability of the facility. Ms Guzeleva noted that the Market Power Mitigation Review proposal is to have a single energy price cap based on diesel generators. • Mrs Papps indicated that it will be difficult to move to a net CONE approach because it is difficult to reconcile the assumed net energy market revenue due to the peakiness in the SWIS and asked how we can deal with this. ○ Mr Robinson agreed that using net CONE will increase the complexity of setting the BRCP and add forecasting error from the need to forecast energy revenue, but indicated that other jurisdictions have managed to deal with this, and advised that we would overcompensate facilities and distort market signals if we do not use net CONE. ○ Mrs Papps sought clarity that, when the five yearly review is considering gross versus net CONE, it should also consider the energy price caps to make sure that they are high enough as we approach scarcity. ○ Mr Robinson suggested that the principle of setting the energy price cap to cover the short-run cost of the most expensive facility can stand regardless of the reference technology that sets the BRCP. • Ms Bedola asked about existing diesel facilities that provide the reserve margin and do not run – if the BRCP is reduced to net CONE for a battery, then how can they cover their fixed costs ○ Ms Guzeleva indicated that these facilities will make their investment decision based on the 160 MW OCGT BRCP and that the energy price cap would let them cover their operating costs based on diesel fuel. ○ Mr Robinson pointed out that the use of the facility will be addressed in determining the net CONE – the net CONE for a	

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	facility would not be much different from its gross CONE if it is not used much. This is why the net CONE calculation is more complex. ○ Mr Stevens pointed out the potential for distortion if someone introduces a very expensive SRMC facility and forces the market to lift the price cap to allow for that unit. ▪ Ms Guzeleva indicated that there should be other measures in the rules to protect against this. ▪ Mr Robinson pointed out that a new entrant facility will not recover its full capital costs if it has higher capital costs than the marginal capacity and its SRMC is at the price cap. A company may do this to increase earnings for the rest of its portfolio, but this is where other market power mitigation measures come into play. ▪ Mr Guzeleva pointed out that the energy price cap is a customer protection measure and is not intended for facilities to bid at the cap. ▪ Mr Stevens and Mr Huxtable raised a concern that a high SRMC facility may be built for non-commercial (green) purposes, which may distort setting the energy price cap. Ms Guzeleva acknowledged this and suggested that a submission could be made to the market power mitigation consultation paper to address this matter.	
7	**BRCP for the Flexible Capacity Product** Mr Robinson led the discussion on the BRCP for the flexible capacity product (slides 13 to 16). • Mr Robinson indicated that: ○ OCGTs and batteries are likely to be able to be provide the flexible capacity product, and facilities would be overcompensated if we set the BRCP for the flexible capacity product higher than the capital cost of the cheapest unit. ○ There may be additional costs for providing the flexibility product, so there may be some differences between the reference technology for peak and flexibility products. ○ The plan is for a future system with no gas-fired facilities, so it could be argued that such plants should be made ineligible for the flexibility capacity, but this is not proposed because there is no policy for the RCM to incentivize low-emissions generation at this stage. ○ The proposal is to set the BRCP for the flexibility capacity product using the same principles as for the peak capacity product, but accounting for any additional technology investment needed for facilities to provide the flexible service. • Ms Bedola indicated that excluding gas would need to be a government policy decision. Ms Guzeleva agreed.	

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	• Ms Bedola indicated that flexible capacity might be limited by Network Access Quantities (**NAQ**) and Mr Cheng agreed that guidance on NAQs would be useful.
	    o Mr Robinson noted that limited NAQ indicates issues with transmission investment and the RCM is not going to be able to solve the problem if a battery cannot be built anywhere on the network and get NAQs.
	    o Ms Bedola suggested that a battery could be built in a place with network congestion, like Muja, because network capacity will become available in the future with the coal retirements, in which case the battery would not get NAQs for a period but would be dispatched before a constrained coal plant.
	    o Ms Guzeleva indicated that a problem emerges if a 160 MW turbine cannot be located anywhere on the system – this becomes a barrier to that technology, so NAQs need to be considered.
	• Mr Peake noted that a flexible gas turbine is likely to be aero derivative, which is likely to be smaller and have higher capital costs. Mr Robinson agreed that we need to understand what the flexibility product is and what the lowest capital cost would be for a facility that can provide the service.
	Mr Robinson led a discussion about the interaction between the peak and flexible capacity products.
	• Mr Robinson indicated that a facility that provides both peak and flexible capacity will need to be compensated to recover the capital costs for whichever service is more expensive to build.
	• The proposal is to set the capacity price as follows:
	    o a facility that provides only the peak capacity product will get the peak capacity price;
	    o a facility that provides only the flexibility capacity product with get paid the flexibility capacity price; and
	    o a facility that provides both products will receive the higher of the peak or flexibility capacity price for providing both products.
	• Mr Price asked, if a facility is providing both products but provides more peak capacity than flexibility capacity, and the price is higher for the flexibility product, would they be paid the higher flexibility price for the peak capacity?
	    o Ms Guzeleva indicated that a tie breaking order would be included in the rules.
	    o Mr Stevens asked, if we have a 200 MW facility that has 180 MW of peaking capacity and 20 MW of flexible capacity, and the flexible capacity price is higher, do we pay all 200 MW at the higher price?
	    o Mr Robinson indicated that this was not the case – the example provided in the slides assumed the facility provides the same	

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	number of MW of each product. The pricing would need to account for any differential in the MW quantity of each product.
	• Mr Shahnazari asked if we will have one marginal price for peak capacity and another for flexible capacity.
	  ○ Mr Robinson indicated that we will have a benchmark price for each product and a reference price for each product, and that the rules already provide for different prices for different facilities.
	  ○ Mr Shahnazari indicated that a market will drive a single marginal price for each product and that infra-marginal rents will drive innovation and efficiency in the market, and suggested that the proposal will deviate from market-based procurement if we have different marginal prices.
	  ○ Mr Robinson indicated that the RCM is an administered mechanism and Mr Shahnazari suggested that the administered mechanism should emulate competitive outcomes.
	  ○ Mr Robinson indicated that there will be two price curves – one for each product, so each product will have a marginal price for capacity, and the problem we are trying to address is what to pay a facility that uses the same capacity to provide both products. For example, a 160 MW OCGT that provides 160 MW of peak capacity and 160 MW of flexible capacity should not be paid the 160 MW times the peak capacity price plus 160 MW times the flexible capacity price.
	  ○ Mr Shahnazari agreed and clarified that his point is that there should be a single price in each market. For example, if we were in a situation where we have lots of peak capacity but need lots of flexible capacity, then the price for the peak capacity should be low and the price for flexible capacity should be high. If we differentiate the price for generators we will deviate from emulating the outcomes of competitive market.
	  ○ Mr Robinson suggested that, in this situation, a facility that provided both peaking and flexibility capacity should be paid more than a facility that only provides peak capacity.
	• In response to a question from Ms Papps, Mr Robinson confirmed that the proposal is to have:
	  ○ different demand curves for each product, but with the same shape;
	  ○ a different target for each product; and
	  ○ a different BRCP for each product, likely higher for the flexibility product.
	• Ms Papps asked how the Individual Reserve Capacity Requirements (**IRCR**) will work and who will pay for the flexible capacity. Mr Robinson indicated that:	

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	○ we have a method to allocate the peak capacity product to participants – IRCR – and this will be considered in the next stage of the review; ○ the way to allocate liability for the flexibility capacity product will also be considered in the next stage of the review; and ○ we may want to allocate liability for the flexibility product using IRCR – this would be simple but may not be fair – or we may want to allocate it based on consumers' contribution to the speed of the ramp. • Ms Bedola asked if a facility would only be accredited for the flexibility product after its mingen – for example, if a 160 MW OCGT had a 60 MW mingen, would its flexible capacity be 160 MW or 100 MW. ○ Mr Robinson indicated that more work needs to be done on what counts to contributing to the flexible capacity product and Ms Guzeleva indicated that an incentive is needed to avoid facilities with a high mingen. • Ms White asked how it will be determined that a facility is flexible – would ESS accreditation be required or would fast ramping capability be sufficient, such as for a curtailed renewable facility. ○ Ms Guzeleva indicated that we are only looking at ramping capability, you would not need to be accredited for any particular ESS at the time of your RCM certification. Mr Robinson indicated that the criteria for qualification as flexible capacity and for ESS accreditation may be similar or the same, but the two would not be linked. ○ Mr Robinson indicated that the initial position was that curtailed renewables would not be able to participate, but feedback from the MAC was that curtailed renewables are the first facilities that you want to provide a flexible service. Mr Robinson indicated that such participation would be limited by the level of certainty that there is availability of such facilities, and Ms Guzeleva indicated that a determination still needs to be made on the obligations on facilities that are accredited for the flexibility product.	
8	**Covering the Duration Gap** Mr Robinson led the discussion on covering the duration gap (slides 17 to 22). • Mr Robinson indicated that the duration gap is currently about 4 hours, it will be 8 hours by the mid-2030s, and likely 16 hours by 2050. • Mr Robinson indicated that the proposal is: ○ for three capability Classes: 1. unrestricted firm capacity;	

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	2. restricted firm capacity; 3. non-firm capacity (intermittent generators); ○ availability obligations will be placed on Classes 1 and 2, but not Class 3; ○ intermittent facilities would be allocated significantly lower CRCs (to be discussed on 21 July 2022); and ○ when there is a capacity shortfall and we are choosing between proposed facilities, facilities in Class 1 will be preferred over Class 2, and Class 2 over Class 3. • Mr Robinson provided a graphical explanation of the duration gap. • Mr Robinson indicated that the RCM needs to provide a signal on the length of the duration gap and an incentive to address it. • Mr Robinson acknowledged advice from some RCMRWG members of the need for investment certainty and the concerns with the idea that the storage availability hours might change for facilities that had been built to particular standards. • Mr Robinson provided a strawman on how to deal with this: ○ AEMO is to publish an availability duration target in the Electricity Statement of Opportunities (**ESOO**); ○ The availability duration target is to be the length of time that needs to be filled, on top of the Class 1 facilities, based on: ▪ the forecast 10% POE load shape (consistent with the peak that we are planning for); ▪ existing and committed Class 1 capacity is fully available; ▪ existing and committed Class 2 facilities are available per some 'transitional arrangements'; and ▪ existing and committed Class 3 facilities' output is as per their CRC. This will allow AEMO to work out a duration that needs to be covered by new facilities and Class 2 facilities will be assessed for CRC based on this availability duration. The 'transitional arrangements' for Class 2 facilities will be that the facility will be assessed: ▪ for 5 years after commissioning, based on the availability duration at the time the facility was built; and ▪ then based on the availability duration at the time. • In response to a question from Mr Peake, Mr Robinson indicated that there will still be a single reserve capacity target and that Capability Classes will work in a similar way to how availability Classes currently work. • Ms Bedola asked if gas facilities will be allowed to opt for a lower duration availability – such as 8 hours instead of 14 hours.	

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	○ Ms Guzeleva indicated that this is correct but that we need to be careful in the short- to medium-term to avoid a situation like in the eastern states, where a facility can opt out for a period and there is insufficient capacity to cover the peak. ○ Mr Robinson indicated that this is one way to deal with fuel duration so the facility owner can choose to have less fuel storage or shorter daily gas supply, but then it will get fewer Capacity Credits. • In response to a question from Ms White, Ms Guzeleva indicated that these arrangements will affect the electricity storage obligation intervals (**ESROI**). Mr Robinson indicated that batteries built further in the future would have longer durations. • Mr Schubert suggested that we will not need all storage to be available for the extended duration unless the peak duration is virtually flat. • Ms White asked if AEMO will set the ESROI on a more granular basis (e.g. at an Availability Class or facility level) and for facilities that enter based on four hours will have that 4 hour period grandfathered. Ms Guzeleva indicated that this is correct and that the grandfathering would be for a 5-year period. • Mr Stevens suggested that metrics around solar irradiance gaps in terms of MW hours will be interesting, if not absolutely critical, even in the near future. This should be a key metric for the ESOO and, if the modelling is robust, will be enlightening in relation how realistic it will be to procure sufficient energy storage. • Mr Shahnazari suggested that the question is whether we pass the investment risk to consumers by setting the ESROI at, for example, 4-5 hours for the batteries that are currently entering the market, or should we leave it open, for example, by applying the Effective Load Carrying Capability (**ELCC**) method to battery storage to signal to the market that the capacity value will change as system stress events happen for longer periods. ○ Mr Robinson agreed that ELCC would account for the effect of different types of events on batteries, but we will need a way to account for duration if ELCC is only used for intermittent facilities. • Ms Ng asked for clarification that the 14-hour fuel requirement is the requirement for Class 1 facilities. ○ Mr Robinson indicated that Class 1 facilities will need to demonstrate that they can be available all of the time but there may be different ways to demonstrate this – maybe the 14 hour fuel requirement should be retained. ○ Ms Guzeleva indicated that a decision has not been made on whether a facility's availability duration impacts its Capacity	

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	Credits, or somehow links to the capacity price – further discussion is required. • Ms White asked if 5-year grandfathering for batteries is long enough. Ms Guzeleva indicated that batteries have a life of about 3,500 cycles, which is 10 years at 1 cycle/day, so a 5-year grandfathering period was selected to provide for more than one cycle per day. • Ms White asked if 'existing or committed' Class 2 facilities means facilities that are already developed and committed, or others that are committed in the medium term before the longer duration is needed. ○ Mr Robinson indicated that the intent is that this will apply to batteries that are committed at the time that the ESOO is done. As an example, Ms Guzeleva indicated that, if you commit to a battery with an 8-hour duration, you will continue to get the arrangements for an 8-hour duration for 5 years from the commissioning date. ○ Ms Bedola asked for confirmation that it is 5-years grandfathering period from commissioning, but the hours are locked in 2 years prior, at ESOO, when you apply for CRC. Ms Guzeleva indicated that the AEMO makes the projection 3 years in advance, but that the 5-year grandfathering period commences after the facility is commissioned. • Mr Peake suggested that, if batteries are to be written down over 5 years, then they will have a very high effective capital cost. ○ Mr Robinson suggested that this would be an extreme approach – it would not be correct to assume that a battery would get no Capacity Credits after the 5-year period. Ms Guzeleva suggested that, in considering the length of the grandfathering period, there is a tradeoff between benefits to facility owners vs shifting risk to customers. ○ Mr Peake noted that, if a battery can last 3,500 cycles, and this will be done in 5 years, then the battery will require a much higher rate of return to cover the capital costs. ○ Mr Robinson indicated that different facilities have different investment models and we need to strike a balance that provides enough investment certainty to make facilities bankable but also leaves enough flexibility so that consumers only pay for what they need. The arrangements need to be technology neutral. ○ Ms Bedola agreed with Mr Peake and asked if the BRCP should allow capex to be recovered over 5 years. Ms Guzeleva indicated that the guarantee is for a 5-year fixed price and that facilities can continue to get Capacity Credits and be paid after that for as long as they can operate.	

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	○ Ms White indicated that she understands why this is being proposed from a policy perspective but that investment certainty needs more consideration, and that this arrangement would make batteries only attractive to the likes of Synergy. ○ Ms Guzeleva clarified that batteries would get a guaranteed capacity price for 5 years and then would get the market prices for as long as the battery can perform at the level it is committed to. ○ Mr Higgins noted that this is similar to the current fixed price arrangements where facilities can opt for a 5-year fixed price that reverts to a floating price after 5 years. Ms Guzeleva agreed and indicated that the rules for batteries may be drafted so the facility owner can choose a 5-years fixed priced or select a floating price. ○ Ms White sought clarity that a battery with a 4 hour interval could continue with a 4 hour interval after the 5 year price arrangement, but its price could be lower if the Class requires an 8 hour interval, not that the 4 hour battery would be required to be available for 8 hours. Mr Robinson indicated that the initial position is that CRC would be assessed on the basis of 8 hour availability. ○ Ms Guzeleva indicated that EPWA would appreciate feedback on whether 5-years is sufficient, but any views need to provide facts about what different technologies can provide, because the RCM is not just about revenue certainty, it is also about providing incentives for market entry for facilities that can meet consumers' needs. ○ Mr Peake indicated that there is a real conflict between the consumers wanting reliability and lower prices, and that they cannot have both. ▪ Mr Robinson noted that there should be an efficient tradeoff between the reliability and price. ▪ Ms Guzeleva agreed that generators need certainty for a period, but that consumer should not be paying for a long period for something that actually does not provide the needed benefits – we need the right balance. • Mr Stevens suggested that the 14-hour fuel requirement needs to be revisited because we do not have a 14-hour peak – instead we have 2 peaks, roughly 5:00 to 9:00 am and 5:00 to 8:00 pm, and this should from the basis of the fuel requirements for Classes 1 and 2. This may be a semi-dynamic calculation, particularly for Class 2, because things like EVs will change the peak demand profiles. ○ Ms Guzeleva agreed that the rules need to set the principles for AEMO to determine the duration rather than specify the	

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	duration, and that AEMO should make the determination in year 1 of each capacity cycle. • Ms Bedola suggested that it sounds like the ESROI decision assumes a 5 year life but the BRCP assumes longer life. When a battery becomes the marginal unit for capacity, the BRCP should be based on a reasonable expectation of the life of the batteries, so 5 years for capex recovery. o Mr Robinson agreed that, when a battery becomes the marginal unit, the BRCP should be based on reasonable expectation of its life. However, the ESROI and the capital recovery period for the BRCP do not have to be the same. For example, it would not be in consumers' interest to guarantee a return on investment for a 15 year facility, but such a facility can opt for a 5-year fixed price arrangement, after which it returns to the floating price – the facility owner makes a commercial investment decision based on these settings. o Mr Shahnazari indicated that, alternatively, the ELCC method could be used for batteries. • Mr Stevens indicated that he does not agree that the determination of capacity prices must factor in investment uncertainty and changes in technology costs. o Ms Guzeleva indicated that we have to be technology neutral and assume that technology will respond to the incentives provided, and the RCMRWG's job is to come up with the right incentives. • Mr Schubert indicated that the party that is best able to manage the risk should bear the risk to ensure efficient outcomes. o Mr Peake suggested that investors have no method to manage their risk where the market is dominated by a Government-owned entity and the Government has interventionist policies. Investors need sufficient protection. o Ms Guzeleva indicated that investors have to take some risk. o Mr Peake pointed out that the Government has made numerous changes to the RCM over the years – taking out the transmission deep costs, then going to the capacity versus excess capacity price, then the Lantau curve – but we have not seen any investment driven by the RCM over the last 10 years. Now we are going into an environment where we want to bring in a lot of storage and wind, so we need an investment environment to bring those on. o Ms Guzeleva pointed out that the problem is that we have had over capacity for a very long time and that capacity prices should go up when capacity is retired over the coming years. o Mr Stevens agreed that capacity efficiency is an objective for the RCM, but not allowing abnormal rents.	

Item	Subject	Action
	○ Ms White agreed that there is risk involved in investment, but WA is relatively risky market in the sense that the policy and the WEM Rules can change rapidly, while investment is lumpy and has a much longer duration. The RCM was designed to provide investment certainty, amongst other things. ○ Ms Guzeleva indicated that the RCM was not intended to provide investment certainty, but to ensure reliability, and that is done by making sure that investments can recover their costs while keeping energy prices efficient.	
9	**Next Steps** Mr Robinson indicated that there is another RCMRWG meeting on 21 July 2022 to discuss alternative methods to Effective Load Carrying Capability to assign CRC. A consultation paper will then be published for comment. Mrs Papps asked what resolutions from the RCMRWG meeting would be brought to the MAC. Ms Guzeleva indicated that the proposal would be outlined in the consultation papers which will be circulated to the MAC.	
10	**General Business** No general business was discussed.	

The meeting closed at 11:30am.

Government of **Western Australia**
Energy Policy WA

Minutes

Meeting Title:	Reserve Capacity Mechanism Review Working Group (**RCMRWG**)
Date:	21 July 2022
Time:	12:45 pm – 2:30 pm
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	
Rhiannon Bedola	Synergy	
Oscar Carlberg	Alinta Energy	Subject matter expert
Manus Higgins	AEMO	until 2:00pm
Jacinda Papps	Alinta Energy	
Brad Huppatz	Synergy	Subject matter expert
Peter Huxtable	Water Corporation	
Sam Lei	Alinta Energy	Subject matter expert
Dimitri Lorenzo	Bluewaters Power	Proxy for Paul Aires From 1:20pm
Mark McKinnon	Western Power	
Patrick Peake	Perth Energy	
Matt Shahnazari	Economic Regulation Authority	From 1:15pm
Peter Shardlow	Analytics Data Science (for Collgar Wind Farm)	Subject matter expert
Noel Schubert	Small-Use Consumer representative	
Rebecca White	Collgar Wind Farm	
Tim Robinson	RBP	
Stephen Eliot	Energy Policy WA (**EPWA**)	
Laura Koziol	EPWA	
Shelley Worthington	EPWA	

Apologies	From	Comment
Dev Tayal	Tesla Energy	
Andrew Walker	South32 (Worsley Alumina)	

Apologies	From	Comment
Dale Waterson	Merredin Energy	
Andrew Stevens	Consultant	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 12:45pm.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	
3	**Alinta's Presentation on an alternative for Certified Reserve Capacity (CRC) Allocation for Intermittent Generators** Mr Carlberg presented Alinta's concerns with the current RLM and the Effective Load Carrying Capability (ELCC) Delta method. The following points were discussed: • In regards to the example on slide 9, that assesses the impact of an additional 1,000 MW windfarm at the location of the Yandin Wind Farm on the CRC allocation to existing wind farms under the delta method, the following was discussed: o Mr Robinson noted that 1,000 WM is a big increase of wind energy nameplate capacity in the SWIS and that such a big new entrant changing the CRC of incumbent wind farms by around 15% was not necessarily a sign that the method produces volatile outcomes. o In response to a question from Mrs Bedola, Ms Koziol noted that the Rule Change Panel had modelled a similar scenario for the assessment of RC_2019_03 and that in this scenario the entrance of the new wind farm had increased the total CRC of the fleet but also reduced the CRC of some of the existing Facilities. • Mr Carlberg summarised Alinta's proposed method for assigning CRC to intermittent generators as follows: o assign CRC based on the average output during the expected times of system stress on the basis of historic peak demand days adjusted for variance as per the current Relevant Level Method, but removing the current k and u factors; o determine the times of expected future system stress as the day time with the highest likelihood of unserved energy, based on RBP's system stress modelling - this would be the Trading Intervals from 4:00 pm to 9:00 pm; and o use the 20 days with the highest system demand for each year of a five-year reference period as the historic peak demand days.	

Item	Subject	Action

- The Chair noted that the 20 days with the highest system demand of every year in the reference period are unlikely to be an adequate representation of system stress. Mr Carlberg clarified that the 95th percentile was chosen to ensure a big enough sample size but that the choice was arbitrary and that Alinta Energy is open to other suggestions.
  - Mr Schubert noted that 20 days are many more days then the annual peak/extreme weather days.
  - The Chair questioned the appropriateness of selecting the same number of days form each year for the peak demand days, noting that the presented analysis showed that, in some years, system demand does not reach a level resulting in system stress. The Chair suggested that choosing the days with the highest system demand in the whole reference period may be more appropriate.
  - Mr Carlberg noted that Alinta Energy considered that the conditions of past system stress event might not represent future system stress events. Mr Carlberg repeated that Alinta Energy is open to other ways for selecting the peak demand days.
- In response to a question form the Chair, Mr Carlberg considered that it would make sense to align the expected future system stress with the Electric Storage Resources Obligation Intervals (**ESROI**). Mr Carlberg considered that the times for expected future system stress could be adjusted but may need to include a transitional mechanism for any changes.
- Mr Eliot noted that, as part of the discussion on RC_2019_03, AEMO had raised concerned about having too many wind farms in a single location such as the North Country, and that one of the reasons the Rule Change Panel proposed the delta method was that the method provides a clear locational signal. Mr Eliot asked how Alinta's proposal addresses this concern.
  - Mr Carlberg indicated that Alinta's proposed method does not account for the correlation of generation from wind farms in the same region. Mr Carlberg noted that Alinta's proposed method focusses on picking intervals expected to be system stress intervals in the future. Mr Carlberg considered that accounting for the correlation of generation of wind farms, in particular over a small amount of intervals, may lead to arbitrary results.
  - Mr Eliot considered that locating all wind farms in the same region could expose the system to potential black outs.
  - Mr Carlberg considered that it is not a problem to locate all wind farms in the same region as long as the weather conditions in that region allow them to be available during the future system stress events.

Item	Subject	Action
	o Mr Schubert considered that the weather conditions that result in system peak often exhibits low wind in the North Country. Therefore, locating all the wind farms in the North Country is an issue for system peak. o Mr Lei considered that such peak days would be accounted for in the proposed method. • In response to a question from Mrs Bedola, the Chair clarified that a method based on historic output needs to include adjustments to account for reduced output due to network constraints. • Mr Eliot noted that setting the CRC for intermittent generators based on their average output during system peak intervals implies that it is acceptable that the capacity will not be available during half of the peak intervals. • Mr Carlberg clarified that the proposal was to use the average output adjusted for variance and that this was based on the current RLM. Mr Carlberg considered the method of weighing the performance in the peak intervals should be based on the desired certainty for the capacity to be available at peak, but that any further discounts below the average output is arbitrary. • Mr Peake suggested that it should be assessed how the proposed method affects system reliability.	
4	**Collgar's Presentation on alternative for CRC Allocation for Intermittent Generators** Ms White presented Collgar's concerns about the delta method, and introduced Collgar's suggested alternative and associated modelling scenarios and outcomes. The following points were discussed: • Ms White summarised Collgar's proposed method for assigning CRC to intermittent generators as follows: o use seven years of historic demand adjusted for distributed PV; o determine the Effective Load Carrying Capability (**ELCC**) for the fleet of intermittent generators as the average of the ELCCs of seven individual years; and o Allocate the fleet ELCC to individual facilities based on relative average performance during defined peak Trading Intervals in each year (the 4 Trading intervals with the highest system demand from the 12 days with the highest demand) of the reference period. • In response to a question form the Chair, Mr Shardlow clarified that the results of the future scenarios on slide 7 are based on the announced retirements of Synergy's coal fired power plants and assumptions on new intermittent generators entering the market. Ms White clarified that the underlying fleet of intermittent generators differs in the different years, based on Collgar's assumptions about	

Item	Subject	Action
	new facilities entering the market, but is the same for any year across the different methods assessed. • Ms White noted that changing the method for allocating the fleet ELCC to individual facilities, as proposed by Collgar, will reduce the valuing of the correlation between different facilities. Ms White considered that this is a trade-off for reducing the volatility of the CRC allocations. Ms White suggested that an alternative approach is to assign fleet ELCC values for groups of facilities in different regions. • In response to a question from Ms Koziol, Ms White clarified that, for the scenario where facilities are grouped by region, Collgar Wind Farm is the only Facility in the east region.	
5	**Next Steps** Mr Robinson noted that further analysis will be undertaken to assess different options to assign CRC to intermittent generators. The Chair reiterated that any method must focus on performance during system stress events and must provide confidence that intermittent generators will perform during times of system stress at the level of the CRC assigned. Mr Robinson noted that the effect of the proposed methods on system reliability will be assessed.	
5	**General Discussion** Mrs Bedola noted that neither the Network Access Quantity regime nor the allocation methods proposed provide adequate locational signals to deter a new facility from locating close to an existing one and reducing the value of the existing facility. The Chair noted that the method must not remove a signal for intermittent generators to firm up their capacity. Several members agreed.	

The meeting closed at 11:30am.

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

Agenda Item 4: RCMRWG Action Items

Reserve Capacity Mechanism Review Working Group (**RCMRWG**) Meeting 2022_10_13

Shaded	Shaded action items are actions that have been completed since the last MAC meeting.
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
10	RCMRWG Secretariat to publish the minutes of the 16 June 2022 RCMRWG meeting on the RCMRWG web page as final.	MAC Secretariat	2022_07_14	**Closed** Minutes published on 14 July 2022.

Government of **Western Australia**
Energy Policy WA

Reserve Capacity Mechanism Review Working Group

Meeting 2022_10_13

13 October 2022

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

Meeting Protocols

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

Agenda

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda	Chair	Noting	5 min
2	Meeting Apologies/Attendance	Chair	Noting	2 min
3	(a) Minutes of meeting 2022_07_14 (b) Minutes of meeting 2022_07_21	Chair Chair	Noting Noting	2 min 2 min
4	Action Items	Chair	Discussion	2 min
5	Purpose of this session	RBP	Discussion	2 min
6	Policy statement principles	RBP	Discussion	15 min
7	Penalty implementation options	RBP	Discussion	45 min
8	Common elements	RBP	Discussion	35 min
9	Options for distributing support payments	RBP	Discussion	30 min
10	Next Steps	Chair	Discussion	5 min
11	General business	Chair	Discussion	5 min

5. Purpose of this Session

Purpose of this Session

- Seeking input on the options EPWA has identified to implement penalties for high emission technologies and support for firming technologies.
- Participants are invited to comment on alternative ways to meet the key policy conditions

6. Policy Principles

Constraints for Penalty Design

The minister issued a draft statement of policy principles in July 2022, and is currently reviewing the principles following input from the MAC. In the meantime, EPWA has begun investigating policy options

The purpose of the policy is to impose a financial penalty on existing and new high emission technologies

Key policy constraints:

1. There will be a penalty on high-emission technologies
2. The penalty will apply to all facilities, new and existing
3. The penalty will be implemented through the WEM
4. The penalty should result in net zero cost impact on consumers
5. The accumulated penalties will be used to incentivize firming solutions to facilitate the growth in renewable intermittent generation

Areas of Flexibility for Penalty Design

EPWA is seeking to examine credible options for implementation of the policy that meet the policy principles

This includes options for penalty application and for distribution of accumulated penalty amounts.

There is flexibility over:

- Implementation through the energy market, the RCM, or as a separate settlement segment
- Where practical, targeting actual facility emissions
- How and what cost of carbon is factored in the relevant calculations
- How accumulated penalties are used to encourage firming technology
- The detail of required processes and calculations

7. Policy Implementation Options

Policy Implementation Options

An important aspect of the penalty design is whether the penalty relates to the actual quantity of emissions produced, or the potential for emissions to be produced

EPWA has identified four main options for implementing penalties based on:

1. estimated emissions produced in each interval
2. estimated emissions produced in each settlement period
3. historical emissions produced in the prior capacity year
4. theoretical maximum emissions that could be produced in each settlement period (least preferred option)

In this session, the latter three options are presented as implemented through the RCM to illustrate the considerations, though they can equally be implemented outside of the RCM.

EPWA intends to model each of these options to estimate emissions penalties for existing and generic new facilities

The method used to distribute accumulated penalty amounts to encourage entry of firming technologies (policy constraint 5) is presented separately to the approach to penalty implementation

Option 1 – Penalty on Trading Interval Emissions

For each facility, determine:

- emissions in each trading interval (tCO2e) as:

  *facility generation (in MWh) * facility emissions rate*

- emissions penalty ($) as:

  *facility emissions * penalty rate*

This option could be applied as a separate settlement segment, or with the penalty subtracted from real time energy market revenues. It would not affect RCM operation.

This option could be applied to all facilities, or only to facilities with annual emissions above a defined threshold – an alternative approach to defining “high emission facilities”

Option 1 – Penalty on Trading Interval Emissions

Under this approach:

- It is expected that owners of high emission facilities would prefer to adjust energy offer prices for those facilities upwards to account for the penalty amount, especially when marginal. Peaking facilities (which are usually marginal when operating) would see the highest impact on short-run operating incentives.
- Allowing emission penalties to be included in offer prices would mean additional costs being passed through to consumers, which would seem counter the purpose of it being a penalty.
- Treatment of penalty amounts would require assessment under the market power mitigation regime, increasing the complexity of ERA activity

This option:

- Would meet policy constraints 2 and 3.
- If penalty amounts are not accounted for in offer prices, may lead to penalties being passed to consumers through contracts initially – thus not meeting policy constraint 4 (net zero impact on consumers) – and then would be a short-run cost to generators once contracts expire.
- If penalty amounts are accounted for in offer prices:
    - o would not meet policy constraint 4, as overall market energy prices would be expected to increase to incorporate the previously externalized emissions cost when high emission facilities are marginal, increasing costs to consumers
    - o may not meet policy constraint 1 (penalty to high emission facilities), as initial analysis suggests that gas facilities could conceivably end up *increasing* profit due to higher infra-marginal rents when coal is marginal

Option 2 – RCM Penalty on Settlement Period Emissions

For each facility:

- determine facility emissions (tCO2e) in settlement period as:

  max(*facility generation, facility capacity credits) * facility emissions rate*

- determine facility emissions per capacity credit (tCO2e/MWCC) as:

  facility emissions / capacity credits

- identify facility reserve capacity price (may be standard, transitional, or fixed) for the settlement period as:

  annual FRCP (in $/MW) / number of settlement periods in a year

- determine emissions-adjusted facility reserve capacity price for the settlement period as:

  *Settlement period FRCP – (Facility emissions per CC * penalty rate)*

- apply emissions-adjusted FRCP to capacity payments, and non-adjusted FRCP to capacity cost recovery calculations

Option 2 – RCM Penalty on Settlement Period Emissions

Under this approach:

- The overall market outcomes should be very similar to option 1
- Participant exposure to refunds would be reduced, as refunds are proportionate to facility RCPs – this would somewhat weaken incentives for availability
- RCM cost recovery calculations would need amendment to ensure that:
    - the full facility RCP is collected from customers, but only the adjusted (reduced) facility RCP is paid out to high emission facilities
    - where capacity credits from a high emissions facility have been bilaterally traded, the penalty is still recovered, either from the generator or the purchaser

Like option 1, this option:

- may not meet policy constraints 1 and 4, if participants can pass penalties through to consumers
- meets policy constraints 2 and 3

Option 3 – RCM Penalty on Historic Emissions

For each facility:

- determine facility emissions in previous capacity year or years (tCO2e) as:

  *facility generation * facility emissions rate / number of years*

- determine facility emissions per capacity credit (tCO2e/MWCC) as:

  facility emissions / average capacity credits in selected years

- identify facility reserve capacity price (may be standard, transitional, or fixed) for the upcoming capacity year
- determine emissions adjusted facility reserve capacity price for the upcoming capacity year period as:

  *FRCP – (Facility emissions per capacity credit * penalty rate)*

Option 3 – RCM Penalty on Historic Emissions

Under this approach:

- Participants would only need to take a view on capacity penalties once per year rather than continuously
- The link between short run operations and long run revenue is weaker and less direct (as operation does not affect capacity payments until the following capacity year), so participants would face less incentive to account for penalty costs in offer prices.
- Using multiple years of historical operation would further reduce the strength of the link between short run operations and long run revenue

This approach would:

- meet policy constraints 2 and 3
- may come closer to meeting policy constraints 1 and 4

Option 4 – RCM Penalty on Theoretical Maximum Emissions

For each facility, determine:

- the maximum possible emissions per CC as:

  *facility emissions rate * hours in year*

- emissions-adjusted facility reserve capacity price for the capacity year as:

  *FRCP – (Facility max emissions per CC * penalty rate)*

Option 4 – RCM Penalty on Theoretical Maximum Emissions

Under this approach:

- Penalties would be independent of short run activity.
- Short run energy prices would still be affected by entry and retirement decisions
- Peaking plant would be much more heavily affected than under other options, potentially leading to accelerated exit, to the detriment of system reliability – this would likely require a threshold
- The same RCM operations considerations would apply as option 2

This approach would:

- Not meet policy constraint 1, as it would apply penalties to facilities with high potential emissions rather than those with high actual emissions.
- meet policy constraints 2 and 3
- If applied without a threshold, may not meet policy constraint 4, as it would be more likely to impact consumers through system reliability measures

8. Common Elements

Facility Emissions Rates

- All penalty collection methodologies require an estimate of facility emissions
- For simplicity, Facility emission rates should be expressed in tCO_2e (tonnes of Carbon Dioxide equivalent) per MWh. The National Greenhouse Emission Register methodologies are based on fuel inputs rather than electrical output.
- The method for setting facility emissions rates could involve (in order of effort):
  (a) setting a default value for each combination of technology type and fuel type
  (b) determining a single emissions content value for each type of fuel, and combining with a facility specific heat rate to determine a single value for each facility
  (c) as for (b) plus developing an efficiency curve with different emission rates for different load levels (e.g. per UNFCC Tool 09 methods A-E)
  (d) as for (c) plus accounting for the composition of the specific gas or coal used in the facility (e.g. per ACER Opinion 22/2019), along with measurement and testing processes, and allocation of some emissions to process heat components of cogeneration facilities
- Preliminary proposal: use option (b) – it balances accuracy with implementation complexity
  - The specific method used would be based on existing methodologies as far as possible, and tie in with assumptions made for other WEM processes that consider emissions, such as the WOSP
- EPWA will quantify expected emissions rates and total quantities for existing and generic new facilities

Emission Penalty Rate

- All methods determine penalty amounts as a function of facility emission quantities and the per unit cost of those emissions (the penalty rate)
- With the same $/tCO2e penalty rate for all facilities (rather than it differing by technology), the penalty rate could be:

  (a) set administratively: either flat, inflation indexed, or increasing over time

  (b) linked to a publicly available emission price index (e.g. for ACCUs, NZUs or European carbon units), changing every settlement period; or

  (c) a historical average of a publicly available emission price index, changing once per capacity year
- Preliminary proposal:
  - link to a publicly available index
  - mitigate volatility by putting bounds on the maximum percentage change per period
  - smooth the impact of the policy by starting from a low-priced index (e.g. from a voluntary surrender program) and transitioning over time to higher-priced indices (e.g. from a compliance based program with binding limits)
- EPWA will quantify the size of penalty at different penalty rates

Meter Data

- Almost all aspects of the WEM operate on a sent-out basis:
  - WEM meter data is measured at the network connection point
  - If WEM meter data is the basis for emission penalty calculations, emissions from energy consumed behind the meter will not be directly measured and penalized
  - If as-generated SCADA data is the basis for emission penalty calculations, settlement calculations would be more complex
- Preliminary proposal: apply penalties on the basis of emissions from *sent-out* energy and factor in the rate of self-consumption when determining emissions rates for each facility

Interaction with other Schemes

- Facilities in the SWIS generation fleet do not currently face financial costs of their emissions
- While emissions from large electricity generators are captured under the safeguard mechanism, the sector as a whole does not currently exceed the baseline, so these emissions are not required to be offset by ACCUs
- It may be appropriate to review the penalty regime if this situation changes – e.g. if the safeguard mechanism sectoral baseline for electricity production is exceeded or if a federal emissions pricing scheme is introduced.

9. Options for Distributing Support Payments

Options for Distributing Support Payments

- Options for distributing support payments are largely independent of how penalties are implemented
- EPWA has identified four main options for distribution of support payments:

1. Distribution to firming facilities pro-rata to Capacity Credits held
2. Adjustment to firming facility reserve capacity prices
3. Contestable fund for new firming facilities
4. Standby fund for non-standard capacity procurement

Option 1 – Distribution to Firming Facilities Pro-Rata to Capacity Credits

- Take the total amount of penalties collected in $
- Sum the Peak Capacity Credits allocated to all low emission firming facilities – those in capability class 1 or 2 which have not paid emissions penalties, or with penalties under a threshold
- Determine the incentive price in $/MW by dividing the penalties collected by the total Capacity Credits held by qualifying firming facilities
- Pay each applicable facility the incentive price * MWCC as part of capacity payments
- Under this approach:
  - Designated facilities would receive an additional revenue stream
  - Additional revenue would depend on the size of the facility and the size of other eligible facilities, not the facility's short-run behaviour.
  - Depending on the penalty approach, the amount of revenue may not be known before real time

Option 2 – Adjustment to Firming Facility Reserve Capacity Prices

- Under penalty options 3 and 4, the total quantity of penalties will be known at the start of the capacity year
- The collected quantity can be allocated through an adjustment to firming facility capacity prices
  - take the total amount of penalties in $
  - determine the total qualifying Capacity Credits as the sum of Capacity Credits allocated to low emission firming facilities
  - identify the facility reserve capacity price (may be standard, transitional, or fixed) for each qualifying facility for the coming capacity year
  - determine support adjusted facility reserve capacity price for the upcoming capacity year period as:

    FRCP + (penalties collected / total qualifying Capacity Credits)

  - apply support-adjusted FRCP to capacity payments, and non-adjusted FRCP to capacity cost recovery calculations

Option 2 – Adjustment to Firming Facility Reserve Capacity Prices

- Under this approach:
  - Designated facilities would receive increased capacity revenue, with the amount known at the start of the capacity year
  - Additional revenue would depend on the size of the facility and the size of other eligible facilities, not the facility’s short-run behaviour
  - Eligible facilities would face higher refunds, slightly increasing incentives for availability
  - RCM cost recovery calculations would need to be amendment to ensure that the adjusted (increased) facility RCP is paid to firming facilities, but the unadjusted facility RCP is collected from customers (i.e. those who have purchased Capacity Credits from firming facilities still pay what they would have paid without the additional support)

Option 3 – Contestable Fund for New Firming Facilities

- AEMO collects penalties in settlement, and pays them into a segregated fund
- A responsible party (likely either AEMO or the Coordinator) specifies characteristics of desired facilities
- Responsible party seeks interest from new entrant firming facilities which are not commercially viable without additional financial support
- Successful respondents are paid out of the segregated fund
- Unpaid funds are distributed to capacity purchasers after 3-5 years.
- Under this approach:
  - significant new processes would be required to design and run competitive tender processes
  - the responsible party would need to assess commercial viability of prospective new entrants – potentially introducing subjectivity into the funding process

Option 4 – Standby Fund for Non-Standard Capacity Procurement

- AEMO collects penalties in settlement, and pays them into a segregated fund
- If/when SESSM, NCESS, or supplementary capacity is needed, AEMO draws on the segregated fund to pay for those costs
- When the fund is exhausted, AEMO allocates any remaining costs under current approaches
- Unpaid funds are distributed to capacity purchasers after 3-5 years
- Under this approach:
  - funds are targeted to specific capacity needs outside of the regular processes
  - collected penalties could sit unused for extended periods of time

10. Next Steps

Next Steps

- RCMRWG members to provide feedback and alternatives by 28 October 2022
- EPWA to analyse likely effects and impact of the various options
- Discuss analysis and indicative approach in next RCMRWG meeting (24 November 2022)
- In parallel, EPWA will continue work on CRC volatility mitigation options (to discuss findings at RCMRWG meeting on 15 December 2022)
- Questions or feedback can be emailed to energymarkets@energy.wa.gov.au

11. General Business

We're working for Western Australia.