RCP Rule Change Panel
Market Advisory Committee

Minutes

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	5 February 2019
Time:	09:35 AM – 12:10 PM
Location:	Training Room No. 1, Albert Facey House 469 Wellington Street, Perth

Attendees	Class	Comment
Stephen Eliot	Chair	
Matthew Martin	Minister's Appointee – Small-Use Consumer Representative	
Martin Maticka	Australian Energy Market Operator (**AEMO**)	
Dean Sharafi	System Management	
Sara O'Connor	Economic Regulation Authority (**ERA**) Observer	
Will Bargmann	Synergy	
Margaret Pyrchla	Network Operator	
Jacinda Papps	Market Generators	
Shane Cremin	Market Generators	
Wendy Ng	Market Generators	
Andrew Stevens	Market Generators	From 9:40 AM
Patrick Peake	Market Customers	
Geoff Gaston	Market Customers	
Steve Gould	Market Customers	
Peter Huxtable	Contestable Customers	

Apologies	Class	Comment
None		

Also in attendance	From	Comment
Aden Barker	Public Utilities Office (**PUO**)	Presenter to 10:20 AM
Claire Richards	Enel X	Presenter
Matt Shahnazari	ERA	Presenter

Julian Fairhall	ERA	Presenter
Oscar Carlberg	Synergy	Observer
Ben Williams	Synergy	Observer
Noel Schubert		Observer
Juan Cifuentes	Energy Made Clean	Observer
Kei Sukmadjaja	Western Power	Observer
Steven Kane	ERA	Observer
Scott Davis	Australian Energy Council	Observer
Natalie Robins	RCP Support	Observer

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1	**Welcome** The Chair opened the meeting at 9:35 AM and welcomed members and observers to the 5 February 2019 MAC meeting.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	
3(a)	**Minutes from Previous Meeting** Draft minutes of the MAC meeting held on 20 November 2018 were circulated on 13 December 2018. The Chair noted that a revised draft showing tracked changes suggested by RCP Support was distributed in the meeting papers. Subject to these changes, the MAC accepted the minutes as a true and accurate record of the meeting. **Action: RCP Support to amend the minutes of the 20 November 2018 meeting to reflect the agreed changes and publish them on the Rule Change Panel's (Panel's) website as final.**	**RCP Support**
4	**Action Items** The closed action items were taken as read. **Action 19/2017:** Open – to be progressed as part of the Wholesale Electricity Market (**WEM**) Reform Program. **Action 33/2017:** In response to a question from the Chair, Mr Matthew Martin advised that the PUO's review of the current list of Protected Provisions would be progressed as part of the WEM Reform Program. **Action 33/2018:** Mr Dean Sharafi advised that System Management issues Operating Instructions to individual Synergy	

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	Facilities for Commissioning Tests, Reserve Capacity Tests, and Network Control Services and Ancillary Service Contracts, but not to the Balancing Portfolio in the situations contemplated in the Rule Change Proposal: Removal of constrained off compensation for Outages of network equipment (RC_2018_07). Mr Martin Maticka noted that Mrs Jacinda Papps had asked at the previous MAC meeting about the implications of recalculating Theoretical Energy Schedule (**TES**) quantities after the current 15 Business Day deadline. Mr Maticka advised that AEMO can and actually has re-run the calculations in the past for various reasons. The Market Participant Interface displays the latest TES calculation results and AEMO also keeps records of previous calculations. Mr Maticka queried whether a change to allow the recalculation of TES should be included in the MAC Market Rules Issues List (**Issues List**), given that it was a fairly straight forward technical implementation. Mrs Papps suggested that a Rule Change Proposal be considered if the IT costs were not as high as previously thought. Ms Jenny Laidlaw noted that AEMO recently provided advice to RCP Support on options to support the late logging of Forced Outages; and in particular on options to ensure that any unwarranted constrained off compensation was recovered through the settlement adjustment process. AEMO had proposed an option involving the recalculation of TES, which RCP Support had discounted due to its high cost. Mr Maticka and Ms Laidlaw agreed to review the assumptions behind the two estimates at a discussion on the Rule Change Proposal: Administrative Improvements to the Outage Process (RC_2014_03) that was scheduled for 8 February 2019. **Action: AEMO and RCP Support to clarify the assumptions behind the IT cost estimates provided to RCP Support in 2018 and to the MAC on 5 February 2019 to support the recalculation of TES after the current 15 Business Day deadline; and to report back on the outcomes to the MAC.**	**AEMO/ RCP Support**
5	**MAC Market Rules Issues List** The MAC noted the recent updates to the Issues List. Mrs Papps requested that a change to allow the recalculation of TES after the current 15 Business Day deadline be included on the Issues List as a potential Rule Change Proposal. The Chair noted his advice from the PUO that the PUO and AEMO intend to consider how to manage future scenarios	

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	where multiple generation units on a single line create the largest credible contingency as part of the WEM Reform Program. The MAC agreed to include this issue on the Issues List, and to place it on hold pending the outcomes of the WEM Reform Program. In response to a question from the Chair, the MAC agreed to delay its next full review of the Issues List until later in the year.	
6	**Update on the Network and Market Reform Program** Mr Aden Barker provided the following updates on the WEM Reform Program. • Mr Barker noted that during the 11 December 2018 WA Electricity Consultative Forum (**WAECF**) he referred to several consultation papers due for imminent release, including a market design proposals paper; an overview paper regarding the WEM Reform Program, its scope and processes, and information about the approach to a cost/benefit analysis or quantitative analysis for the benefits of reform; and a final report for the proposed Reserve Capacity Mechanism (**RCM**) pricing changes and draft exposure Market Rules. However, a new Minister for Energy was appointed shortly after this WAECF meeting, which has understandably led to some delay in the release of those papers. • The PUO met very recently with the Minister to discuss the reform program in general, providing an overview of the proposed process and scope, as well as details of the proposed RCM pricing changes. The Minister had also met with various stakeholders from industry about these matters. The PUO received broad support from the Minister for the shape and form of the reform program, for the release of the consultation papers (which now need to go through the internal processes of review and to the Minister), and also for the RCM pricing changes. The PUO was finalising those pieces of advice for the Minister for his consideration and subsequent public release. • With respect to the RCP pricing changes, the intent and advice to the Minister is that acting now will reduce the risk of needing to defer the 2019 Reserve Capacity Cycle. • While the release of papers has been delayed, this was not delaying the work being undertaken under the reform program. For example, the PUO has received advice from its consultants with regard to Ancillary Services definitions that are appropriate now and in the future; and was also reviewing advice on a future generation mix.	

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	• The first Market Design and Operation Working Group (**MDOWG**) meeting is scheduled for 20 February 2019. While the market design proposals consultation paper may not be published by then, the PUO proposed to discuss the essence of the proposals and elicit feedback from attendees. The PUO also intended to have one of its consultants provide an overview of the approach to be taken for quantitative analysis to assist with developing various proposals, and to quantify the net benefits for the reform package as a whole. • The PUO will also provide a forward agenda for the remaining MDOWG meetings. The PUO was planning monthly meetings in the first instance, but considered it highly likely that additional meetings will be needed. The PUO intended to follow a fairly similar format for the MDOWG meetings to that established by the Power System Operation Working Group (**PSOWG**). • Mr Barker noted that everything presented in the proposed consultation papers will have been previously discussed at a MDOWG or PSOWG meeting. • The initial due diligence and examination of issues by AEMO and the PUO suggests that there will be ways for large-scale storage to participate in the WEM before the revised market arrangements commence in October 2022. The PUO planned to provide further information on the matter at the next MAC meeting. In response to questions from Mr Shane Cremin, Mr Barker advised that: • the PUO had engaged GHD to undertake the Ancillary Services definition work; and • the PUO's initial view was that the Standard Rule Change Process would not allow the RCM pricing changes to be implemented in the required timeframe, so the changes would need to be implemented via the Minister's repeal and replace powers. Mr Barker noted that the 20 February 2019 MDOWG meeting would be held at Albert Facey House. Mr Sharafi advised that the next PSOWG meeting will be held on 11 February 2019. Agenda items included updates on the proposed constraints framework, the primary frequency control modelling being undertaken by AEMO, and the ancillary services framework that GHD is working on with AEMO.	
7	**AEMO Procedure Change Working Group (APCWG) Update**	

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	Mr Maticka advised that the next APCWG meeting is planned for 21 February 2019, and will discuss Market Procedure changes relating to the Rule Change Proposal: Reduction of prudential exposure in the Reserve Capacity Mechanism (RC_2017_06). The MAC noted the update on AEMO's Market Procedures.	
8(a)	**Overview of Rule Change Proposals** The MAC noted the overview of Rule Change Proposals.	
8(b)	**Calculation of Relevant Demand for Demand Side Programmes** Ms Claire Richards from Enel X gave a presentation in support of Enel X's Pre-Rule Change Proposal regarding changes to the method used to calculate the Relevant Level of a Demand Side Programme (**DSP**). A copy of the Pre-Rule Change Proposal is available in the meeting papers. The following points were discussed. • Mr Cremin asked how Capacity Credits for a DSP would be determined if the baseline for the DSP was dynamically determined using information available only days before an event. Ms Richards replied that under the National Electricity Market's Reliability and Emergency Reserve Trader (**RERT**) program, Enel X receives availability payments for a portfolio of 30 MW, and also receives energy payments whenever it is dispatched. AEMO generally assumes the 30 MW is available, but will contact Enel X if a dispatch seems likely to confirm that the full quantity will be available for dispatch. • Mr Andrew Stevens considered that a dynamic baseline methodology would be good for determining energy payments, but reiterated Mr Cremin's concern about how the dynamic baseline method could be used to determine Capacity Credits. Ms Laidlaw noted that DSPs are allocated Capacity Credits before they are required to identify any Associated Loads. This means that the current static baseline of a DSP is also uncertain until just before an event. However, if the DSP's Relevant Demand is too low for its Capacity Credits then the Market Customer is liable for Capacity Cost Refunds. • Mr Stevens expressed a preference for the current 'interim' arrangements, under which DSPs receive a lower capacity price but a higher energy price when dispatched. Mr Stevens considered that the current baseline methodology was unfair under the current arrangements.	

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	However, if DSPs were to receive the same level of capacity payments as generators, then a methodology based on consumption during the 12 peak Trading Intervals used for Individual Reserve Capacity Requirement (**IRCR**) calculation (**IRCR Trading Intervals**) would be problematic.	
	• Mr Peter Huxtable noted that if DSP baselines were calculated using the median consumption of the Associated Loads during IRCR Trading Intervals, a 1 MW Load would receive payment for 1 MW of capacity. However, in addition to having to make the capacity available when required, the Load would still incur IRCR costs for around 1.4 MW, i.e. the Load would still be liable for the additional 0.4 MW.	
	• Mr Geoff Gaston noted that previously it was proposed to determine the baseline contribution of an Associated Load using its IRCR contribution, i.e. its median consumption adjusted by the relevant TDL_Ratio or NTDL_Ratio. Mr Gaston and Mr Huxtable agreed that the ratio-adjusted values should not be used to calculate DSP baselines, as they did not represent the available capacity of the Associated Loads.	
	• There was some discussion about the problems of using a static baseline for Loads with variable consumption patterns.	
	• Mr Ben Williams noted that if the baseline was set using median consumption over the IRCR Trading Intervals, then in half of those Trading Intervals the Load's consumption would be insufficient to provide all the capacity for which it was being paid. Mr Williams considered that if a generator could not meet its Reserve Capacity Obligation Quantity 50% of the time then serious questions would be asked about whether it should be receiving that number of Capacity Credits.	
	Ms Richards replied that under the current methodology a DSP would typically be consuming at a significantly higher level than its baseline for a large proportion of its required 200 hours. Ms Richards considered there was very little reason for Loads in most industry sectors to provide this quantity of reduction for free, even if DSPs were to receive the same capacity price as generators. Ms Richards predicted that no DSP capacity would return to the market under the current baseline methodology. Mr Stevens considered that this would not be a problem at present.	
	• Mr Williams noted that under the proposed Relevant Level Methodology the output of wind farms would be likely to exceed their Capacity Credit level most of the time. There	

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was some discussion about the services provided by DSPs and Non-Scheduled Generators and the extent to which their certification should be harmonised.

- Ms Laidlaw noted that the previous Minister increased the capacity obligation for DSPs from 24 hours to 200 hours. Ms Laidlaw considered that, leaving aside whether a median or probability of exceedance approach should be used, the number of Trading Intervals required to calculate a static baseline in part depended on how many hours the DSPs might be needed. Ms Laidlaw questioned why 200 hours had been selected and whether DSPs needed to be available for this long.

  Mr Martin noted that the Electricity Market Review had sought greater harmonisation of the requirements for DSPs and generators, and the 200 hour requirement was based on the time period when it was considered that DSPs could be providing value.

- In response to a question from Mr Cremin, Ms Richards explained that RERT contracts are individually negotiated and there is no transparency around the pricing arrangements, which can include different combinations of capacity and energy payments.

- Ms Richards asked whether MAC members agreed that Enel X's concern with the current baseline methodology was an issue that should be consulted on through a Rule Change Proposal. Mr Cremin and Mr Stevens considered there was a case for changes to the baseline methodology under the current capacity pricing arrangements. However, they were opposed to DSPs receiving the full Reserve Capacity Price on the basis that they provided an energy product and not a capacity product. There was extensive discussion about the capacity and energy services provided by DSPs and how they should be remunerated by the market.

- Mr Cremin suggested the Supplementary Reserve Capacity concept should be reviewed, because it could provide an appropriate mechanism to manage the contribution of DSPs to the market. Mr Williams and Mr Maticka questioned whether limiting DSPs to the provision of Supplementary Reserve Capacity would produce the most efficient outcomes when the market needed a small additional quantity of capacity. Mr Williams noted that the initial certification process for a Capacity Year occurs two years before the trigger point for Supplementary Reserve Capacity.

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	Mr Patrick Peake advised that on the occasion the IMO called for Supplementary Reserve Capacity it received numerous offers, all from DSPs. Mr Peake confirmed that the capacity was not actually used and there was no transparency around the contract prices.	
	• Ms Laidlaw noted that AEMO had developed dynamic baselines to support the RERT, and questioned to what extent AEMO may be able to re-use this work for the WEM. Mr Maticka advised that AEMO would need to look into the detail to see how transportable the calculations were.	
	• Mr Peake considered that if DSPs were to receive the same capacity payments as generators, then it would not be acceptable for them to have a baseline that was frequently above their actual consumption level. Mr Peake agreed with Mr Cremin that too much DSP capacity had been removed from the market, but felt that DSP availability requirements and capacity prices needed to be considered as a package. Mr Williams agreed with the views expressed by Mr Peake.	
	• Mr Maticka advised that AEMO could not determine how straightforward the changes would be to implement until it saw the drafting of the proposed Amending Rules, and suggested that Enel X amend the wording of its Pre-Rule Change Proposal accordingly.	
	• Mr Huxtable agreed with Ms Richards that the proposed changes to the capacity price for DSPs will not bring any more DSP capacity into the market unless changes are also made to the baseline methodology.	
	• The Chair noted the different views expressed during the discussion, and considered that future discussion should not be restricted to the approach put forward by Enel X in this first draft Pre-Rule Change Proposal. The Chair suggested that it may be useful to look at how other capacity markets treat the demand side management (**DSM**) product.	
	• There was some discussion about the proposed changes to RCM pricing, how these changes would apply to DSPs, and the effect of a large-scale return of DSP capacity (i.e. 500-600 MW) on the capacity payments of existing and future generators.	
	• Ms Richards advised that Enel X could investigate how other markets certify DSM capacity two years in advance and send its findings to the Chair for circulation to the MAC. However, Ms Richards observed a need for a fundamental discussion about the role of DSPs in the RCM, and	

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	questioned whether this should occur through Enel X's Rule Change Proposal or some other mechanism. There was some discussion about options to further consider these broader questions. The Chair noted that further MAC discussion of the issues could be scheduled, but questioned the relative urgency of this work. There was general agreement that this was a relatively low priority issue, at least until the final paper for the Minister's changes to RCM pricing was released. • Mr Cremin questioned the independence of research undertaken by Enel X into other capacity markets. Mr Stevens considered the required investigation and development of Rule Change Proposals should be undertaken by the agencies funded by Market Participants (i.e. AEMO and the ERA). There was some discussion about the role of these agencies and the PUO in market development, and the relative priority of this issue compared with the current work programs of those agencies. • The Chair noted that the MAC did not appear to consider the issue had a higher priority than the work being done under the WEM Reform Program. Enel X was however free to submit a Rule Change Proposal and/or provide further information to the MAC for its consideration. • Ms Richards considered the main concerns related to how to certify capacity two years in advance under a dynamic baseline approach, and how much should be paid for DSP capacity. Ms Richards offered to investigate these questions, and provide extracts of rules and details of people who could be contacted to verify the information provided. The Chair agreed that this additional information would be helpful. • Mr Williams noted that the WEM was one of the few capacity markets that did not also have a scarcity price for energy.	
8(c)	**Behind-the-meter generation affecting a facility's NTDL status** Mr Stevens provided an overview of the issue discussed in the agenda item paper, which relates to the installation of a solar PV system at a site changing the load at the site from a Non-Temperature Dependent Load (**NTDL**) to a Temperature Dependent Load (**TDL**). Mr Stevens considered the example raised a broader question of whether the NTDL and TDL concepts were still relevant given	

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	the changes to system demand over recent years. On a more detailed level, Mr Stevens questioned whether the specific issue could be resolved by installing a revenue-quality meter on the PV system, and using the interval data to adjust the site's metered demand in the relevant Trading Intervals for the purpose of NTDL assessment.	

The following points were discussed.

- Ms Laidlaw considered that while it may be reasonable to assess the site as a 40 MW NTDL, it would not be reasonable to assess it as a 37 MW NTDL because the site was regularly consuming at 40 MW during peak Trading Intervals.

  Ms Laidlaw suggested that another option could be to allow a Market Customer to nominate its NTDL MW consumption level, which would replace the calculated median value for IRCR calculation provided the Load did not exceed that consumption level. Mr Cremin considered that this approach would be consistent with what was done in the past in relation to NTDLs.
- Mr Williams considered that Mr Stevens' suggestion for a solar PV adjustment would effectively assign a 'median' capacity value to those PV systems, while other solar facilities were assigned a capacity value based on a probability of exceedance. This would create very different incentives for solar capacity in front of the meter and behind the meter.
- Mr Williams questioned whether the NTDL calculations reflected their intent. Mr Cremin explained that the current version of the NTDL calculation was introduced to account for the Boddington load, which did not qualify as an NTDL under the original calculation because of differences between its day-time and night-time demand.
- Mr Cremin noted that when the TDL and NTDL concepts were developed there was a strong desire to incentivise temperature-independence, due to concerns about the rate at which peak system demand was increasing. Mr Cremin questioned whether the system was still as temperature-dependent and whether the rationale for the TDL and NTDL classification still applied.
- There was some discussion about the appropriateness of the current IRCR calculations and the associated classification of Loads as TDLs or NTDLs, in particular given the changing SWIS demand profile.

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	• Mr Peake suggested that the issue could be considered as part of the ERA's annual review of the effectiveness of the WEM (**WEM Review**). Mr Williams asked whether the issue was included on the Issues List. Ms Laidlaw replied that a broader issue for preliminary discussion, which covered several RCM issues that were not being addressed by the WEM Reform Program, was included on the Issues List. • Mr Williams asked whether the PV system in Mr Stevens' example could be registered as a generator, and metered and assessed for RCM purposes separately to the load. Mr Cremin and Mr Gaston considered that this would not provide a simple solution due to the network connection issues involved.	
9	**Wholesale Electricity Market Review 2017/18 Discussion Paper (presentation – no paper)** Mr Julian Fairhall gave a presentation to the MAC on the ERA's discussion paper for its 2017/18 WEM Review. A copy of the presentation is available on the Panel's website. Mr Fairhall sought input from the MAC on the issues raised in the discussion paper. The following points were discussed. • In response to a question from Mr Cremin, Mr Fairhall confirmed that the cost stack prices in slide 3 of the presentation were expressed in real rather than nominal terms. In response to a question from Mr Stevens, Mr Fairhall clarified that the carbon adjusted energy prices in slide 3 related to Balancing Prices. • In response to a question from Mr Stevens, Mr Fairhall clarified that the ERA found the output of coal plant remains comparable with previous years in absolute terms. • Mr Will Bargmann asked whether the gas fuel prices shown on slide 4 of the presentation were spot prices. Mr Fairhall replied that suppliers are obligated to report to the Government their revenue under the royalty framework, and the prices in slide 4 were determined from the total revenues reported divided by the total volumes reported. The prices did not therefore take into account downstream swaps or what was occurring in the spot market, where prices were actually lower. Mr Bargmann considered that the prices may be misleading because they did not take into account certain minimum terms that generators have to enter into to meet their obligations, such as those under the Market Rules. Mr Bargmann noted that a generator of Synergy's size had no	

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	choice but to lock into long-term contracts, the effect of which was not reflected in the prices in slide 4. Mr Fairhall asked if Mr Bargmann expected a new generator would pay above the gas prices shown. Mr Bargmann replied that he did not currently expect any new generators to enter the market, but did not consider this indicated a lack of competition. Mr Williams considered that no generators wanted to enter the market because there is already too much competition. Mr Fairhall considered that just because it was difficult to compete in a market did not mean the market was competitive. • Mr Peake considered that part of the issue related to the difference between the buy-back price for rooftop solar ($71/MWh) and mid-day Balancing Prices. Mr Peake expressed a fear that the Government would provide a subsidy for batteries that failed to achieve its intended outcomes, and suggested that the 'duck curve' problem would continue to grow without better policy around the management of solar buy-back. • Mr Peake agreed with Mr Bargmann that no new generators were likely to enter the market. • Mr Cremin considered that the ERA's index for energy prices was too high, and suggested that tracking the prices on a monthly basis showed a bigger variation in pricing arising from the changing dynamic of demand in the SWIS. Mr Cremin suggested that while prices were lower in the middle of the day, this was leading to higher prices in the evening and morning peaks because of the need for fast ramping. Mr Cremin noted that the peak was being met with industrial gas turbines that were not well suited for flexible running up and down. It was unclear whether the lower day time prices or the higher peak period prices had the dominant effect. • Mr Cremin considered that, contrary to the general assumption, there had been a large reduction in demand over the last two years, with a further reduction in January 2019 despite that month being hotter than usual. Mr Maticka and Mr Fairhall noted that temperatures in the SWIS were actually below average over January 2019. • Mr Sharafi asked what the ERA meant by "planning systems" in slide 9 of the presentation. Mr Fairhall replied that the ERA was interested in whether the Reserve Capacity Cycle planning mechanisms were actually identifying the opportunities that exist. Mr Sharafi noted that this covered only one aspect of the market, and considered	

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	that to be able to identify the right opportunities for the market, the planning needed to look at every aspect of the market and the system. There was some discussion about the work being undertaken by the WEM Reform Program on the need for an integrated system plan. • Mr Stevens suggested that the current higher energy prices may to some extent be due to unavoidable costs associated with the transition from the old generation mix to the new (e.g. losses relating to long-term contracts and plant becoming unviable). • Mr Cremin noted that over $2 billion had been spent on solar PV in the SWIS. • There was some discussion about the Government's response to the ERA's previous WEM Reviews; and whether the reviews should be conducted less frequently (e.g. every 2-3 years). • Mr Stevens noted that he had recently asked the Minister about the battery-related pilot projects being conducted by organisations including Synergy, Power Ledger and Western Power. Mr Stevens' question was whether the purpose of the projects was to determine what was needed to open these opportunities to the broader market, or to provide a competitive advantage to the organisations involved. Mrs Papps noted that the Government's inquiry into microgrids and associated technologies in WA was looking at that exact question. Mrs Papps considered it was important to ensure that different reviews did not duplicate each other's work. Mr Fairhall suggested that if stakeholders indicated any related submissions to other reviews in their WEM Review submission, the ERA would be able to take this additional information into account. Mr Fairhall noted that the submission period for the WEM Review closed on Friday 8 February 2019.	
10	**Review of the Method for Capacity Valuation of Variable Generation** Dr Matt Shahnazari gave a presentation to the MAC on the ERA's review of the Relevant Level Methodology. A copy of the presentation is available in the meeting papers. The following points were discussed. • Mr Williams queried the reason for allocating the fleet capacity value among individual Facilities using both peak demand and peak 'load for scheduled generation' (**LSG**)	

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Trading Intervals, rather than just using peak LSG Trading Intervals. Dr Shahnazari replied that, for example, solar Facilities will tend to move the periods of minimum surplus to later in the day when their own performance is lower. Not including peak demand Trading Intervals might fail to recognise the capacity contribution made by these Facilities.

Mr Williams questioned whether it was inconsistent to value the fleet based on loss of load probability and then allocate that capacity to individual Facilities based on a different measure. Dr Shahnazari noted that once the minimum surplus was no longer occurring in the early afternoon, any additional solar would not increase the fleet capacity value. Dr Shahnazari suggested this would provide a deterrent to further investment in solar. Mr Williams questioned whether additional solar in these circumstances would be a problem for other generators, as it would not increase the fleet value, but would be awarded a share of that value because of its performance at times of peak demand.

- Mr Cremin considered that the increasing penetration of solar (both behind-the-meter and Registered Facilities) would increase the Capacity Credits for wind farms while reducing the Capacity Credits of solar Facilities. Mr Cremin questioned whether solar Facilities needed Capacity Credits to be viable.
- Mr Gaston asked how the proposed methodology would be affected by situations where multiple generators on a single transmission line comprise the largest credible contingency, and some of those generators are constrained off to avoid excessive Spinning Reserve costs; and in particular how the Capacity Credits of those generators would be affected. Dr Shahnazari noted that the PUO's proposed method for allocating Capacity Credits under a constrained network access regime took network and security constraints into account. Dr Shahnazari considered that the Relevant Level Methodology also taking these constraints into account might cause some 'double counting'.
- Ms Laidlaw noted that the methodology made assumptions about the availability of Scheduled Generators, which could be affected by the operation of network constraints. Dr Shahnazari considered that if a Scheduled Generator was heavily constrained by network congestion then it might become necessary to develop a way to include this information in the model. However, the model currently developed by the ERA did not do this.

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11	**MAC Schedule** The MAC noted the MAC meeting schedule for 2019.	
12	**General Business** No general business was discussed.	

The meeting closed at 12:10 PM.