RCP Rule Change Panel
Market Advisory Committee

Meeting Agenda

Meeting Title:	Market Advisory Committee
Date:	Tuesday 26 November 2019
Time:	9:30 AM – 11:45 AM
Location:	Training Room No. 2, Albert Facey House 469 Wellington Street, Perth

Item	Item	Responsibility	Duration
1	Welcome	Chair	5 min
2	Meeting Apologies/Attendance	Chair	5 min
3	**(a)** Minutes of Meeting 2019_10_15	Chair	5 min
	(b) Minutes of Workshop 2019_10_18 re RC_2017_02 (Implementation of 30-Minute Balancing Gate Closure)	Chair	5 min
	(c) Minutes of Workshop 2019_11_18 re RC_2014_03 (Administrative Improvements to Outage Process)	Chair	5 min
4	Actions Items	Chair	5 min
5	MAC Market Rules Issues List	Chair	20 min
6	Update on the Energy Transformation Strategy (no paper)	ETIU	15 min
7	AEMO Procedure Change Working Group Update	AEMO	5 min
8	Rule Changes		
	(a) Overview of Rule Change Proposals	Chair	5 min

Item	Item	Responsibility	Duration
	(b) North Country Spinning Reserve Issue (discussion – no paper)	Chair	25 min
	(c) Market Participant Fee calculation manifest error	AEMO	15 min
	(d) Data and IT Procedure Options	AEMO	10 min
9	General Business	Chair	5 min
	(a) MAC Call for Nominations 2020	Chair	5 min
Next Meeting: 11 February 2020			

Please note, this meeting will be recorded.

RCP Rule Change Panel
Market Advisory Committee

Minutes

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	15 October 2019
Time:	9:30 AM – 11:30 AM
Location:	Training Room No. 2, Albert Facey House 469 Wellington Street, Perth

Attendees	Class	Comment
Stephen Eliot	Chair	
Matthew Martin	Minister's Appointee – Small-Use Consumer Representative	
Mark Katsikandarakis	Australian Energy Market Operator (**AEMO**)	Proxy for Martin Maticka
Teresa Smit	System Management	Proxy for Dean Sharafi
Sara O'Connor	Economic Regulation Authority (**ERA**) Observer	
Andrew Everett	Synergy	
Shane Duryea	Network Operator	Proxy for Margaret Pyrchla
Dimitri Lorenzo	Market Generators	Proxy for Daniel Kurz
Jacinda Papps	Market Generators	
Wendy Ng	Market Generators	To 11:20 AM
Erin Stone	Market Customers	Proxy for Patrick Peake
Geoff Gaston	Market Customers	
Tim McLeod	Market Customers	
Chayan Gunendran	Market Customers	
Peter Huxtable	Contestable Customers	

Apologies	Class	Comment
Martin Maticka	AEMO	
Dean Sharafi	System Management	
Patrick Peake	Market Customers	

Margaret Pyrchla	Network Operator	
Daniel Kurz	Market Generators	
Andrew Stevens	Market Generators	

Also in Attendance	From	Comment
Kate Ryan	Energy Transformation Implementation Unit (**ETIU**)	Presenter to 11:05 AM
Miles Jupp	ETIU	Presenter to 11:05 AM
Matthew Fairclough	AEMO	Presenter to 11:20 AM
Jenny Laidlaw	RCP Support	Minutes
Noel Schubert	ERA	Observer to 11:20 AM
Kei Sukmadjaja	Western Power	Observer
Kim Phan	ETIU	Observer to 10:35 AM
Julius Susanto	AEMO	Observer to 11:20 AM
Richard Cheng	RCP Support	Observer
Natalie Robins	RCP Support	Observer
Sandra Ng Wing Lit	RCP Support	Observer

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30 AM and welcomed members and observers to the 15 October 2019 MAC meeting.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	
3(a)	**Minutes of Meeting 2019_09_03** Draft minutes of the MAC meeting held on 3 September 2019 were circulated on 11 September 2019. The MAC accepted the minutes as a true and accurate record of the meeting. **Action: RCP Support to publish the minutes of the 3 September 2019 MAC meeting on the Rule Change Panel's (Panel's) website as final.**	**RCP Support**

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3(b)	**Minutes of Workshop 2019_09_06 re RC_2017_02** Draft minutes of the MAC workshop held on 6 September 2019 to discuss Rule Change Proposal: Implementation of 30-Minute Balancing Gate Closure (RC_2017_02) were circulated on 25 September 2019. The Chair noted that a revised draft showing suggested tracked changes on pages 12 and 14 was distributed in the meeting papers. The Chair invited comments or questions on the draft minutes, while noting they were to be discussed further at the second MAC workshop for RC_2017_02 that was scheduled for 18 October 2019. The MAC raised no questions or concerns about the draft minutes.	
4	**Action Items** The closed action item was taken as read. **Action 19/2019:** The Chair advised that the ERA was still considering the matter. Ms Sara O'Connor added that the ERA was in the middle of working through a number of questions raised by AEMO regarding the Pre-Rule Change Proposal. **Action 20/2019:** The Chair noted that AEMO would provide an update on the North Country Spinning Reserve issue under agenda item 8(b).	
5	**MAC Market Rules Issues List (Issues List) Update** The MAC noted the recent updates to the Issues List. The Chair noted that RCP Support had deferred the annual review of the Issues List, which was due to be held at this meeting, until the November 2019 MAC meeting. <u>Outage Issues for Potential Inclusion on the Issues List</u> The Chair noted that the paper for this agenda item included seven outage-related issues that were raised by stakeholders during consultation on Rule Change Proposals: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15) and Administrative Improvements to the Outage Process (RC_2014_03), but did not fall within the scope of those proposals. The Chair sought the views of the MAC on what should be done with these issues. Ms Jenny Laidlaw provided an overview of the seven outage issues. The MAC agreed that the following issues should be added to the Issues List and placed on hold until the relevant outcomes of the Energy Transformation Strategy (**ETS**) are	

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	known (i.e. the regulatory changes for the Foundation Regulatory Frameworks workstream): • identification of services subject to outage scheduling; • outage scheduling for dual-fuel Scheduled Generators; • Ancillary Service outage scheduling anomalies; • outage scheduling obligations for Interruptible Loads; • direction of Self-Scheduling Outage Facilities; and • outage scheduling obligations for non-intermittent Non-Scheduled Generators. Ms Wendy Ng asked why the Ancillary Service outage scheduling anomalies issue had been raised. Ms Laidlaw replied that the main concern raised related to Interruptible Loads that provided Spinning Reserve Service under an Ancillary Service Contract. While such Facilities were required to be included on the Equipment List, it was not clear who was responsible for scheduling outages for the Facility with System Management. Ms Laidlaw noted that Alinta had raised the sixth issue, “Coordination of network and generator outages”. Mrs Jacinda Papps advised that recently there were numerous Planned Outages affecting the Generator Interim Access (**GIA**) Facilities, and questioned whether those Planned Outages were coordinated or planned in a way that optimised overall market outcomes. Mrs Papps considered the issue more of a philosophical question to discuss before the development of any Rule Change Proposal, but suggested that over time, particularly once three or more GIA generators were commissioned, the need for greater coordination would increase. However, Mrs Papps noted that Alinta had observed a recent improvement in ‘on the day’ GIA impacts. The MAC supported Mrs Papps’ suggestion to not include the issue on the Issues List at this time.	
6(a)	**Update on the ETS** Ms Kate Ryan provided the following updates on the ETS. • The Energy Transformation Taskforce (**Taskforce**) was to meet for the seventh time on 18 October 2019. The Taskforce would receive updates on the Whole of System Plan (**WOSP**), the development of a Capacity Credit Rights proposal (to support the implementation of constrained access), and a stocktake of the projects, pilots and trials underway in Western Australia and other states that are	

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providing information to assist development of the Distributed Energy Resources (**DER**) Roadmap.

- ETIU expected to circulate a paper on the Capacity Credit Rights proposal shortly, for discussion at the next meeting of the Transformation Design and Operation Working Group (**TDOWG**).
- Since its commencement, the Taskforce had published ten information papers, nine relating to elements of the wholesale market reform, and one relating to the WOSP.
- The TDOWG was meeting on roughly a monthly basis, with the next meeting scheduled for 22 October 2019. ETIU was also meeting regularly with Western Power and AEMO on most aspects of the work program.
- The Program Implementation Coordination Group, which comprised senior representatives from the Taskforce, AEMO and Western Power, met for the fourth time the previous week. The Strategic Consultative Group was scheduled to meet for the second time later in October 2019.
- The next Industry Forum would discuss the DER Roadmap and provide a chance for ETIU to report on what it had learnt from the previous workshop, provide an update on the development of the roadmap and seek further feedback from stakeholders. Details of the forum, which was scheduled for 29 October 2019, would be emailed to stakeholders shortly.
- ETIU had held over 100 one-on-one meetings with stakeholders, mostly in relation to the WOSP and DER integration. ETIU expected to hold more such meetings, which it believed has proved a very effective way of engaging with the sector.

Mrs Papps considered that the recent decision not to implement 5-minute settlement on 1 October 2022 was very sensible, and asked what process would be used to decide the new implementation date. Ms Ryan replied that ETIU was working with AEMO on what was required to implement 5-minute settlement, with the intention of providing the Taskforce with another decision point before the end of 2019. Depending on how far the work progresses, this would produce either a revised implementation date or a process for determining the date. The revised implementation date would be some period beyond October 2022.

In response to a question from Mrs Papps, Ms Ryan confirmed that ETIU was considered several options for implementing

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	5-minute settlement and considered it likely that the Taskforce would be able to provide more details, including a firm target implementation date, by the end of 2019. Ms Ng asked whether the Taskforce was expected to make any decisions about constrained network access and Capacity Credit allocations at its 18 October 2019 meeting. Ms Ryan replied that the Taskforce would only receive an update at this meeting. The next decision on these matters would be around the design of the Capacity Credit Rights proposal. ETIU was working on the detailed design for Capacity Credit Rights with the aim of receiving Taskforce approval by the end of 2019. Ms Ryan expected that prior to this decision the matter would be discussed at two TDOWG meetings as well one-on-one consultations with each affected Market Generator.	
6(b)	**Update on the WOSP** Mr Miles Jupp provided an update on the modelling methodology, inputs and assumptions developed for the WOSP. A copy of the presentation (updated from the earlier version that was circulated in the meeting papers) is available on the Panel's website. The following points were discussed: • Ms Ng noted Mr Jupp's comment that he had spoken to potential developers and lenders about their likely cost of capital and expected rates of return, and asked how their expectations compared with the relevant assumptions in the latest draft determination of the Benchmark Reserve Capacity Price (**BRCP**). Ms Ng indicated that the Weighted Average Cost of Capital (**WACC**) used in the draft determination was around 3.35-3.36%. Mr Jupp replied that ETIU had been looking at expected internal rates of return (**IRRs**) under various circumstances. The expected IRRs were generally under 10% for new renewable Facilities with an off-take agreement. However, risk premiums were added for Facilities that used fossil fuels, with the highest risk premiums applied to coal plant, and some lenders noting that funding coal plant into the future could become very expensive. The risk premiums for gas plant were lower, around 10-15% based on comparisons with new gas plant being built in the National Electricity Market. Mr Jupp noted that expected IRRs were dropping, and an investor was often prepared to accept much lower terms if a project fitted its risk profile. Ms Ng considered that a disconnect between the BRCP and the assumptions made	

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	by investors could prevent any further generation from being built. • In response to a question from Mr Chayan Gunendran, Mr Jupp confirmed that the least cost expansion modelling would consider the curtailment or management of DER. Mr Jupp explained that the demand assumptions for the four scenarios had been adjusted to reflect different assumptions about the uptake and usage of solar PV and batteries. Mr Gunendran considered that the least cost solution could involve curtailing or managing DER. Mr Jupp noted that one of the major outputs of the WOSP was to drive policy and decisions about the management of DER. Several options existed to deal with DER, and the aim was to identify the best options in terms of lowest system cost. Mr Jupp invited stakeholders to contact him if they wished to discuss any aspects of the WOSP on a one-on-one basis.	
7	**AEMO Procedure Change Working Group (APCWG) Update** Mr Mark Katsikandarakis advised that the next APCWG meeting would be held on 21 October 2019 and would deal with a minor administrative change to the Market Procedure: Prudential Requirements to correct an error in the documented Credit Limit calculation. The MAC noted the update on AEMO's Market Procedures.	
8(a)	**Overview of Rule Change Proposals** The Chair noted that: • the proposed workshop for RC_2014_03 was scheduled for 25 October 2019, not 24 October 2019 as shown in the meeting papers; • the Draft Rule Change Report for Rule Change Proposal: Managing Market Information (RC_2014_09) was due to be published on 18 October 2019; and • the second workshop for RC_2017_02 was scheduled for 18 October 2019. The MAC noted the overview of Rule Change Proposals.	
8(b)	**North Country Spinning Reserve Issue** Mr Matthew Fairclough provided an update on AEMO's action item 20/2019: *"AEMO to develop a Pre-Rule Change Proposal for AEMO's 'option 3' to address the North Country Spinning Reserve issue*	

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(as discussed at the 29 July 2019 MAC meeting), which is to include the removal of constrained off payments when the relevant generators are constrained down to reduce the Spinning Reserve requirement, for presentation at the 26 November 2019 MAC meeting."

A copy of AEMO's presentation is available in the meeting papers.

The following points were discussed:

- Mr Fairclough noted that the connection of the two new GIA generators (Yandin and Warradarge) would increase the potential size of the largest single contingency to 730 MW. Mr Fairclough noted that the Network Operator has an obligation to reduce the maximum size of this entire contingency such that when System Management has sufficient Spinning Reserve the contingency will not require under frequency load shedding.
- In response to a question from Ms Laidlaw, Mr Fairclough clarified that while curtailment of the GIA generators to reduce the size of the contingency may increase the Balancing Price, it would not be expected to result in the payment of additional constrained on compensation.
- Ms Ng noted that an unconstrained network access regime still applied in the SWIS and questioned why NewGen Neerabup should not receive constrained off compensation if it was constrained off.
- Ms Laidlaw sought clarification on whether NewGen Neerabup was part of the combined single contingency under system normal conditions, noting that AEMO had previously advised that a network outage was needed for NewGen Neerabup to form part of the single contingency. Mr Shane Duryea confirmed the NewGen Neerabup would be part of the combined single contingency under system normal conditions.
- Mr Fairclough explained how the current dispatch rules would determine the order in which the GIA generators and Newgen Neerabup would be constrained if there was a need to reduce the size of the contingency. Ms Laidlaw noted that the default dispatch order could be modified through the rule change process to account for these situations in a more appropriate way.

  Mrs Papps noted that a 180 MW limit on the output of the GIA generators would significantly reduce the low-cost energy that these generators could provide to the market. Ms Laidlaw agreed that option 2 was likely to be a more

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	efficient option, but noted the MAC had been under the impression that option 2 was not achievable in the required timeframe. While this no longer appeared to be the case, option 2 may still not be viable, or else not viable within the required timeframe, so option 3 was still of interest, possibly as a short-term solution. Mr Fairclough advised that option 3 would probably take longer to implement and be at least as difficult to implement as option 2. Mr Fairclough acknowledged that the dispatch rules could be amended but did not think that AEMO would suggest such changes in a Rule Change Proposal.	
	• In response to a question from Mr Noel Schubert, Mr Fairclough reconfirmed that AEMO's modelling had taken into account the local loads and other factors that would tend to reduce the impact of the contingency.	
	• Mr Fairclough provided an overview of AEMO's proposed changes to the full runway Spinning Reserve cost allocation method. Mr Fairclough confirmed that NewGen Neerabup and the two new GIA generators would be part of the same contingency group, and that NewGen Neerabup was likely to incur greatly increased Spinning Reserve costs as a result. Ms Laidlaw considered that this might be problematic and asked if any other GIA generators were expected to be sharing a single contingency with other generators, noting that the GIA program had now closed and so the location of all the GIA generators was known. Mr Duryea replied that he did not think any other GIA generators would be sharing a single contingency in this way.	
	• There was some discussion about the guidelines for contingency group definition, and whether the Eastern Goldfields generators should be assigned to a single contingency group given that the loss of the relevant transmission line would cause a Load Rejection Reserve event rather than a Spinning Reserve event.	
	• Ms Laidlaw noted that RCP Support had considered a contingency-based version of the full runway cost allocation method as part of its work on Rule Change Proposal: Full Runway Allocation of Spinning Reserve Costs (RC_2018_06). RCP Support had rejected the idea on the grounds that it would impose an unacceptable financial burden on NewGen Neerabup. However, Ms Laidlaw considered it was possible to modify AEMO's proposed method to avoid this problem, and	

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suggested that AEMO and RCP Support discuss that option further.

- Mr Fairclough confirmed that AEMO proposed to determine the contingency groups on a dynamic basis (i.e. separately for each Trading Interval). Ms Laidlaw considered that using dynamic contingency groups was likely to be a more complex and expensive option than using static contingency groups, and questioned the necessity for dynamic contingency groups given the purpose of the cost allocation mechanism. Mr Mark Katsikandarakis agreed that using static contingency groups could result in a simpler implementation.
- There was some discussion about the likely impact of the new GIA generators on the Balancing Price and the frequency of NewGen Neerabup's operation.
- Mr Fairclough suggested that, in a situation where a Scheduled Generator (such as NewGen Neerabup) was part of a contingency that might need to be limited, then the Scheduled Generator might be prevented from operating at its full output, which in turn could affect its eligibility for Capacity Credits.

  There was some discussion about whether the current certification process for GIA generators took security constraints into account, and whether the reduction of existing generators' Capacity Credits due to the effects of GIA generators was an intended outcome.

The Chair noted that there was general agreement at the previous MAC meeting that AEMO should develop a Pre-Rule Change Proposal based on option 3 for discussion at the November 2019 MAC meeting. The Chair questioned whether the MAC had changed its view following AEMO's update.

Mr Schubert considered that option 2 was generally the preferred option, and the MAC had chosen option 3 only because it was considered more implementable. Mr Geoff Gaston considered that AEMO had steered the MAC to option 3 on the basis that it was the faster option, and that his preference was by far for option 2. Other MAC members also expressed a preference for option 2.

Ms Laidlaw asked whether AEMO would start work on the 5-7 month implementation of option 2 before the publication of a Final Rule Change Report, as this would affect whether the changes could be implemented before the GIA generators commenced operation and before the 2020/21 margin values took effect. Mr Katsikandarakis replied that AEMO would need

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	to consider this further. However, if there was general endorsement for option 2, then AEMO could hopefully prepare a Pre-Rule Change Proposal for the November 2019 MAC meeting, which would contain more accurate advice on the implementation timeframes.	
	Ms Laidlaw noted that, when the Panel was considering Rule Change Proposal: Removal of constrained off compensation for Outages of network equipment (RC_2018_07), it had sought to avoid changes that could be seen to breach the perceived rights of generators with ‘firm’ network access.	
	Ms Laidlaw and Mr Katsikandarakis agreed to meet to discuss alternative changes to the full runway Spinning Reserve cost allocation method. Ms Ng requested to be involved in this discussion, while Mr Fairclough suggested that representatives from Synergy and Alinta should also be invited to attend.	
	Ms Ng noted that she objected to the proposal presented by AEMO, primarily because ERM Power had no say in becoming part of a group contingency and did not consider itself a part of a group contingency.	
	Ms Laidlaw suggested it would be helpful to confirm which if any of the other GIA generators will be sharing lines with existing generators so that the affected generators can be made aware of the situation and can participate in the discussion of the issue.	
	Mr Katsikandarakis advised that AEMO would use its best efforts to develop a Pre-Rule Change Proposal for the November 2019 MAC meeting, but may not be able to achieve this deadline if the proposed discussions resulted in significant changes to the current thinking on the proposal.	
	Mr Gaston acknowledged the complexity of the issues but considered the prevention of unwarranted constrained off compensation was a priority that needed to be progressed quickly. There was some discussion about the time required to implement the proposed changes to remove constrained off compensation, the expected commissioning dates for the GIA generators, and the potential to use a staged commencement if the preferred solution could not be implemented in the required timeframe.	
	Action: AEMO to develop a Pre-Rule Change Proposal for AEMO’s ‘option 2’ (i.e. option 2a and 2b) to address the North Country Spinning Reserve issue, as discussed at the 29 July 2019 MAC meeting, for discussion at the 26 November 2019 MAC meeting.	**AEMO**

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	Action: AEMO and RCP Support to discuss options for changes to the full runway Spinning Reserve cost allocation model to account for the largest single contingency comprising multiple generators, and to invite ERM Power, Alinta and Synergy to participate in those discussions.	**AEMO/RCP Support**
8(c)	**Pre-Rule Change Proposal: Administrative Improvements to Settlement** Mr Katsikandarakis provided an overview of AEMO's Pre-Rule Change Proposal: Administrative Improvements to Settlement (RC_2019_04). The Pre-Rule Change Proposal is available in the meeting papers. The following points were discussed: • Mr Katsikandarakis presented a slide (available on the Panel's website) showing an example of the proposed timeline for Notices of Disagreement. Mr Katsikandarakis advised that while developing this example AEMO found a minor drafting error in the Pre-Rule Change Proposal (i.e. the deadline for Notices of Disagreement specified in clause 9.16.4(e) should be the first Business Day of the eleventh month following the commencement of the Trading Month being settled, not the first Business Day of the tenth month). • Mr Katsikandarakis noted that RCP Support had indicated that section 9.24 of the Market Rules (Settlement in Default Situations) also needs to be updated to account for Ancillary Service Providers. AEMO intended to review this section and include the required changes in RC_2019_04. • The Chair noted that RCP Support had received an email from Skyfarming expressing its concerns that the minimum invoice amount for which a payment must be made (currently set to one dollar in clauses 9.22.6 and 9.22.8) is less than the cost of processing the payment. Skyfarming suggested increasing the minimum invoice amount to ten dollars. Mr Katsikandarakis noted that AEMO used Austraclear to facilitate settlements in the market, and that Austraclear charged between five and ten dollars per transaction. The MAC was generally supportive of Skyfarming's suggestion and Mr Katsikandarakis advised that AEMO was happy to include the proposed change in RC_2019_04, although it would need to give some thought to how any unsettled amounts should be handled from an accounting perspective.	

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	• The MAC generally supported the progression of RC_2019_04 into the formal rule change process. • In response to a question from Ms Laidlaw, the MAC confirmed that it did not consider there was a need for any additional changes to the calculation of Theoretical Energy Schedules beyond those proposed in RC_2019_04 (e.g. broader changes to require recalculation of values using interval meter data). • The Chair sought a recommendation from the MAC on the urgency rating for RC_2019_04, noting that AEMO proposed a High urgency rating because of its compliance concerns associated with the issue. Mr Katsikandarakis noted that AEMO did not want to be in a situation where it might have to let the market settle with manifestly wrong outcomes, or else be demanding the submission of Notices of Disagreement from Market Participants. AEMO preferred that the changes were put in place as soon as possible, so that AEMO could settle the market with the most accurate information available. Mrs Papps considered that a High urgency rating was appropriate given the importance of accurate settlement. The MAC was generally supportive of a High urgency rating for RC_2019_04.	
9	**Review of the Framework for Rule Change Proposal Prioritisation and Scheduling** The Chair noted that RCP Support reviewed the Panel's Rule Change Proposal Prioritisation and Scheduling Framework (**Framework**) following a discussion of the Framework with the Gas Advisory Board (**GAB**) in 2018. The Framework is intended to apply to both the GSI Rules and the Market Rules, but was originally drafted from a Market Rules perspective. RCP Support discussed several proposed changes to the Framework with the GAB at a recent GAB meeting, and now intended to conduct a public review process for the proposed changes. RCP Support proposed to publish the draft Framework by the end of October 2019 and seek submissions from participants in both the gas and electricity markets. The intention was to present the changes for approval at the Panel meeting scheduled for December 2019, with the revised Framework to take effect from 1 January 2020. The Chair invited questions or comments on the proposed changes from the MAC.	

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	The following points were discussed: • Mr Peter Huxtable asked where RC_2019_04 would fit into a single queue for changes to the Market Rules and GSI Rules. The Chair replied that RCP Support continued to be of the view that it would not make sense to maintain two sets of resources, one for electricity and one for gas. However, if a single pool of resources is applied to both queues then the effective outcome will be the same as if a single queue is used. Ultimately, if a Rule Change Proposal is assigned a high priority it will go to the top of RCP Support’s task list, regardless of whether the change is to the Market Rules or the GSI Rules. • In response to a question from Mrs Papps, the Chair and Mr Richard Cheng advised that the GAB had not raised any key issues or concerns about the proposed changes to the Framework. • Mr Matthew Martin noted that the GAB had not had much experience with dealing with Rule Change Proposals or applying the Framework, as they had only dealt with two Rule Change Proposals since the Panel commenced operation. Mr Martin considered that GSI Rule Change Proposals would not rate highly under the current Framework because they are not of a nature that they are likely to compromise system security. The Chair considered that this was a fair observation, and that the greater risk with the one queue approach was that a GSI Rule Change Proposal might be continually pushed down the queue. However, the Chair noted that the Panel had made some progress in reducing its backlog of proposals.	
10	**General Business** Workflow Reporting: The Chair noted that the MAC asked for additional information on RCP Support’s work program at the previous MAC meeting. The Chair understood that this was to assist stakeholders in their planning by giving them a better understanding of the events that were expected to occur in the immediate future. The Chair proposed to add a new section at the start of the Overview of Rule Change Proposals (**Overview**) (which is tabled at each MAC meeting) listing the events that are expected to occur before the next MAC meeting (e.g. workshops and consultation periods). Alternatively, RCP Support could add a new column to the report showing the target date of the next	

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	step rather than the official date. The Chair noted that in some cases the official ‘next step’ dates on the Panel’s website did not reflect the actual target dates. The Chair sought the views of MAC members on the proposed changes. Mrs Papps noted that after a period of relatively little activity several market events had been scheduled over a six-business day period, including two MAC workshops, an APCWG meeting and a TDOWG meeting. The Chair suggested that listing such events at the start of the Overview would help stakeholders with their planning. Ms Laidlaw noted that RCP Support sought to avoid scheduling events that conflicted with, or occurred too close to, events held by other agencies such as ETIU, and that to do this it was helpful to know the dates of these events as early as possible. The Chair indicated that RCP Support would update the Overviews as discussed, and invited future feedback from members about the effectiveness of the changes.	

The meeting closed at 11:30 AM.

RCP Rule Change Panel
Market Advisory Committee

Minutes

Meeting Title:	RC_2017_02 Implementation of 30-minute Balancing Gate Closure Workshop
Date:	18 October 2019
Time:	10:00 AM – 12:00 PM
Location:	Training Room 1, Albert Facey House 469 Wellington Street, Perth

Attendees	Class	Comment
Stephen Eliot	RCP Support	
Jenny Laidlaw	RCP Support	
Natalie Robins	RCP Support	
Richard Cheng	RCP Support	
Sandra Ng Wing Lit	RCP Support	
Matthew Fairclough	Australian Energy Market Operator (AEMO)	
Dean Sharafi	AEMO	
John Nguyen	Perth Energy	Conference call
Martin Maticka	AEMO	
Brad Huppatz	Synergy	
Quentin Jeay	Kleenheat	
Paul Arias	Bluewaters Power	
Tim McLeod	Amanda Energy	
Sam Lei	Alinta Energy	
Erin Stone	Perth Energy	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 10:00 AM and welcomed those in attendance.	
2	**Apologies/Attendance** The Chair noted the attendance as listed above.	

Item	Subject	Action
3	**Minutes of 6 September 2019 Workshop regarding RC_2017_02: Implementation of 30-minute Balancing Gate Closure** The Chair noted that the minutes from the workshop on 6 September 2019 (the first workshop) had been distributed to workshop attendees on 25 September 2019 and that two comments had been received. The revised minutes were tabled at the Market Advisory Committee (**MAC**) meeting on 15 October 2019. The MAC noted the minutes and had no further comments. Attendees had no further comments on the minutes from the first workshop.	
4	**RC_2017_02 Workshop** Ms Natalie Robins led discussion for the workshop.	

Slide	Subject	Action
3-4	**Review of First Workshop Discussions** Ms Robins noted that the main outcome of the first workshop was the introduction of AEMO's new perspective on the use of LFAS only to address uninstructed fluctuations in output (such as from wind and solar), not instructed fluctuations from the ramping of Scheduled Generators. Up until now LFAS has been and is still being used to address fluctuations from the ramping of Scheduled Generators. AEMO considered that, at a 60-minute Balancing Gate Closure (**BGC**), its only option to address the aggregate ramp issue is to displace Synergy's Balancing Portfolio to offset the aggregate ramp of Independent Power Producers (**IPPs**). Automated linear ramping will be required where the forecast ramp of the Balancing Portfolio is less than the aggregate ramp of IPPs. Whilst there is no definition around how the linear ramping process will work, there will be cost and time implications associated with automation of this process. Additionally, given that there is a market reform program underway, any changes that are made to implement a linear ramping process will need to be made to fit on top of the existing system rather than making wholesale changes to the system.	

	Ms Robins noted that in the first workshop, AEMO identified three options for responding to aggregate non-Synergy scheduled movements in a Normal Operating State, which were to: (1) displace the Balancing Portfolio to offset it, if it is in the Trading Interval and the Balancing Portfolio is available to move within the Trading Interval; (2) dispatch the Balancing Portfolio in advance of the Trading Interval to reduce the impact and duration of use of LFAS Facilities; and (3) constrain non-Synergy Facilities. AEMO had considered at the first workshop that option (2) was not feasible, and since then has also discounted the use of option (3). In explanation, Mr Matthew Fairclough reasoned that issuing Dispatch Instructions to non-Synergy Facilities that are causing the aggregate ramp issue (option 3) is effectively linear dispatch. Mr Fairclough explained that, instead of issuing a Dispatch Instruction at the ramp rate that the participant put in their Balancing Submission, AEMO will come up with a different ramp rate, whilst keeping the quantity in the Dispatch Instruction the same. Ms Jenny Laidlaw questioned whether the option to hold one of the generators back for some period had also been discounted. Mr Fairclough confirmed that this option was no longer a consideration and had not been investigated further. Mr Fairclough considered that the biggest issue with staggered ramping is that the delayed Facility will not meet the quantity requested in its Balancing Submission. This is effectively dispatch out of merit, which can only be done to avoid a High Risk Operating State under the rules. Ms Robins questioned whether this interpretation was correct. If the network is in a Normal Operating State and there is a potential to enter a High Risk Operating State, the intention is for AEMO to take steps to avoid the High Risk Operating State before it occurs. Mr Fairclough considered that there is a conflict because the Market Rules require that out of merit dispatch can only be used to avoid a High Risk Operating State, and if AEMO get into that situation because of an action that they take in the first instance, they are precluded from using it. Mr Dean Sharafi clarified that a High Risk Operating State is linked to the physical state of the grid and the risk associated with it, and should not be the result of participant bidding behaviour. Mr Paul Arias considered that options that require a tweak to the Market Rules should not be excluded. Mr Fairclough warned that while any rules can be amended, it may produce unforeseen outcomes and that AEMO would be reluctant to further consider such an amendment. Mr Brad Huppatz considered that the alternate solution was to move the Balancing Portfolio out of merit within the interval to accommodate instructed outputs, which was inconsistent with	

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	Synergy's Balancing Portfolio clearing volumes. Mr Huppatz considered that applying an output variance to the Balancing Portfolio to accommodate the instructed output variance did not seem to be consistent with the Wholesale Market Objectives. Ms Robins noted that there was inconsistency in the arguments being put forward because, in the case of linear ramping, it was suggested that constraining Market Participants was okay but, in the case of staggered ramping, it was not an option. It was agreed that this discussion should be continued off-line later. Ms Robins noted that AEMO's position on a 90-minute BGC at the last workshop was that it would use the Balancing Portfolio to offset the aggregate ramp of IPPs but that it would not have to be done automatically and could be done manually. This would mean fewer cost and time implications, although Market Participants would still need to adjust their systems to allow for linear ramping. Additionally, AEMO would have the ability to dispatch Synergy's units ahead of the Trading Interval. For example, Synergy's coal plant could be ramped down ahead of the Trading Interval to allow gas plant to position itself so that it can ramp down rapidly at the start of the Trading Interval to offset the aggregate ramp up of IPPs. However, as Synergy indicated in the first workshop, this option is quickly being eroded, as Synergy is increasingly operating at its minimum generation and does not have room to ramp down further.	
5	**New System Management Analysis** Ms Robins noted that since the first workshop, AEMO had been working on determining how frequently the aggregate ramp of IPPs will be an issue, requiring linear dispatch. AEMO had developed a formula to predict when linear dispatch is required and applied it to 2018/19 to determine that linear ramping would be required in about 10% of Trading Intervals (about five times per day) at a 60-minute BGC, and in about 7% of Trading Intervals (about three times per day) at a 90-minute BGC. Ms Robins cautioned however, that AEMO had considered an extreme scenario in which LFAS cannot be used to address the aggregate ramp issue so the only option that it would have is to displace the Balancing Portfolio to offset the aggregate ramp issue. Mr Fairclough considered that the findings for the 90-minute BGC option were the same for a two-hour BGC, and that the added half an hour didn't really make that much of a difference as far as determining what AEMO can do in advance. Ms Laidlaw questioned whether, to stop using LFAS, AEMO's plan was to use linear ramping in the 7% of Trading Intervals that the aggregate ramp issue occurs in. Mr Fairclough considered that if the market is not going to a 60-minute BGC, there are 7% of intervals where the Balancing Portfolio's ability to offset all other movements are exceeded, but because it has a bit more time and more options,	

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	things do not need to be automated and can be dealt with manually. Mr Fairclough considered that this may change at some point in the future but AEMO can deal with it right now as it is. Ms Laidlaw questioned whether AEMO intends then to go to linear ramping on a manual basis as soon as it can. Mr Fairclough considered that AEMO is not intending to introduce manual linear ramping immediately. Mr Fairclough explained that, if the gate closure is more than 60 minutes, AEMO will assess when it gets to a point when it must implement linear ramping. Ms Laidlaw pointed out that the aggregate ramping issue is happening now in 7% of intervals. Mr Sharafi clarified that going to a 90-minute BGC is not going to change the process by which AEMO dispatches. Ms Laidlaw questioned whether it would matter if AEMO was eating into the LFAS quantities in this situation. Mr Sharafi considered that LFAS is currently being used to enable aggregate ramping of generators and the situation would remain the same. Mr Arias questioned whether AEMO had outlined a view at the start of the workshop that it should not be using LFAS, as it was risking system security. Mr Sharafi noted that it is his view that AEMO should only use LFAS when it does not have any other choice. At the start of the interval, AEMO depletes some level of LFAS because that is the reality of dispatch. Ms Laidlaw noted that the incidence of the aggregate ramp issue seems very high at 7% and asked whether there are problems in the system due to volatility such that AEMO is not able to risk using LFAS. Ms Laidlaw questioned why the risk materialises and must be acted on for the extra 3% at the 60-minute BGC and not at the 90-minute BGC. Mr Fairclough considered that saying there is a 3% difference doesn’t capture all aspects of the issue. Mr Fairclough handed out a series of slides and asked attendees to consider the table in the final slide, representing the results of the back-casting analysis on the 2018/19 data. Mr Fairclough explained that AEMO: • only has what the Balancing Portfolio can move in the 60-minute BGC scenario; and • can dispatch more in advance in the 90-minute scenario. Mr Fairclough considered the 3% difference between the two scenarios in terms of the Trading Intervals when the aggregate ramp issue occurs requires that 20% of the energy would be constrained, which is reasonably significant. At a 60-minute BGC the issue occurs in 10% of the intervals, which is too much to rely on LFAS Facilities. Effectively, at a 60-minute BGC the impost is too much for AEMO to determine which Trading Intervals would be manageable, so a blanket cut-off would be employed such that LFAS could not be used any time the threshold is exceeded.	

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6	**Scope of the Rule Change Proposal** Ms Robins noted that RCP Support had received legal advice that LFAS Gate Closure could be amended under the current Rule Change Proposal. However, RCP Support had also received advice that the Rule Change Proposal is about 'accuracy of information' and that amendments to the Market Rules are not within scope if they are not about this topic, such as the introduction of staggered or linear ramping. Ms Robins considered however, that this did not provide a barrier to moving to a 60 or 90-minute BGC, as AEMO had indicated that it could implement linear ramping without changes to the Market Rules. There was some discussion on whether amendments to Synergy's gate closure were within the scope of the Rule Change Proposal and it was agreed that this is within scope.	
7	**Benefits and Costs of the Options** Ms Robins noted that shorter BGCs lead to greater accuracy of information, and lesser risk to Market Participants due to changing circumstances. However, there are costs for both AEMO and Market Participants due to the requirement for automated linear ramping at the 60-minute BGC, which is essentially a short-term solution to the aggregate ramp issue until the market reforms come into place. Consideration also needs to be given to the fact that AEMO cannot begin to look at making changes to its systems until mid-2020. Mr Sam Lei questioned whether linear ramping is going to be implemented even if the BGC is not changed. Mr Fairclough considered that at present AEMO is not expecting to need to implement linear ramping soon, but it will have to reassess this next year. Mr Lei noted that Alinta has significant concerns about its machines, which are tuned to a certain ramp rate and will be very unstable if they are required to ramp at different ramp rates, and there will be a risk of them tripping more often. Ms Laidlaw questioned whether, before AEMO decides to move to linear ramping under any circumstances, as opposed to putting on more LFAS or using other options (such as constraining people off occasionally), AEMO had looked at the overall costs and benefits, including the costs of generators upgrades and constrained on and off payments. Mr Fairclough confirmed that AEMO would consider all these issues before it introduced linear ramping. However, the information that it provided in the slides was a starting point on how it can survive a move to a 60-minute BGC. Mr Fairclough considered that the costs include constrained on and off payments and loss of energy for generators, and if there are generators that need to modify their	

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	facilities to comply with the existing Market Rules, then that would have to be considered as well. Ms Laidlaw noted that at the last workshop AEMO indicated that it was going to implement linear ramping and the question was whether it would have to be automated or not. Mr Fairclough confirmed this but suggested that the point was that AEMO may need to get to it at some stage, but it has not foreseen a need to introduce it yet. Mr Huppatz questioned whether AEMO's adopted interpretation, that LFAS can only be used for uninstructed fluctuations, meant that AEMO would have to apply linear ramping in the 7% of cases where the aggregate ramping issue occurs now. Mr Fairclough explained that with that definition of LFAS the requirement does not change and AEMO is bearing the risk of eating into the available LFAS. Mr Sharafi confirmed this perspective, noting that at the beginning of the Trading Interval, AEMO eats into the LFAS but, as you move forward into the Trading Interval, the risk becomes smaller and smaller. Mr Arias questioned whether, if AEMO is already using LFAS, and even though it has mentioned that it is not supposed to be using it, AEMO has considered using and enabling more LFAS, and not moving to linear ramping. Mr Sharafi confirmed that this was a consideration. Mr Arias questioned further whether consideration had been given to whether automatic linear ramping was lower cost or getting more LFAS per Trading Interval was lower cost. Mr Fairclough explained that the issue is that the definition of LFAS does not include instructed changes. Mr Arias considered that AEMO is already eating into the LFAS to address instructed fluctuations, regardless of how LFAS is specified. Mr Fairclough argued that this was not the case, and that AEMO had set its requirement ignoring instructed changes. Mr Fairclough explained that AEMO was eating into that requirement at certain times and the question was about how often we can live with that risk. Ms Laidlaw questioned whether the Market Rules were necessarily the sticking point, considering that AEMO had technically not previously been setting the requirement according to the Market Rules, as it would not have provided enough LFAS for the system. Ms Laidlaw cautioned however, that putting on additional LFAS may be a high cost option, particularly if the SWIS starts to run out of generation. Mr Fairclough considered that AEMO did not necessarily share this position. Mr Arias drew attention to a comparison of the costs associated with 90-minute BGC and the current 120-minute gate closure and questioned whether a lot of the costs associated with the 90-minute BGC would already be in the 120-minute BGC. Mr Fairclough confirmed that the difference between the 90- and 120-minute	

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	BGCs would be zero. Mr Arias considered that, on this basis, the starting point is a 90-minute BGC. Ms Laidlaw questioned whether AEMO had done any more work on how the manual linear ramping process would work and how at 90 or 60 minutes out, AEMO would determine what it needed to do and how it would change the ramp rates to linear ramp rates in the Real Time Dispatch Engine (**RTDE**). Mr Fairclough noted that whilst it had not done any more work in this area, there was an existing manual process that allowed it to override the ramp rates. Ms Laidlaw questioned how AEMO would work out the ramp rates for each generator and load them into the RTDE in time for each dispatch cycle. Mr Fairclough considered that AEMO would go through the same process that it used to work out when the linear ramping Trading Interval would occur, and at that point everyone's quantities would be divided by the time, and that would produce the linear ramping rates. Ms Laidlaw questioned the practicality of this approach, given the timing requirements and that changes in demand and dispatch can occur within the ten-minute dispatch cycle, and asked at what stage AEMO would work out the dispatch requirements and input the ramp rates. Mr Sharafi considered that this was the controller's decision, based on their consideration of the conditions and determining what ramp rate each generator needs to get to the point that they need to be at. Ms Laidlaw considered that the controller may need to override the ramp rate of only one or two generators rather than everyone and questioned whether it would be necessary to switch everyone over to linear ramping, which is quite involved. Mr Sharafi noted that AEMO has not done this yet, so it has not yet determined its process. Mr Fairclough considered that the problem is that it's more difficult to do the calculation to pick a winner than just to say that, unfortunately, everyone loses, and if AEMO did pick winners, it would have to have a process for determining who would be the winner, which would be quite challenging. Ms Robins questioned whether AEMO has previously used linear ramping. Mr Fairclough noted that every now and again it had had to vary the ramp rates of Facilities, but not on a regular basis, and it was usually only for one or two Facilities. Mr Huppatz considered that AEMO routinely move the Balancing Portfolio outside of its clearing volumes to accommodate the ramping issue. Mr Fairclough considered that AEMO moves the Balancing Portfolio to ensure power system security. Ms Robins questioned how AEMO determined who is causing the aggregate ramp issue. Mr Fairclough explained that most of the time AEMO deals with the aggregate ramp issue by dispatching the	

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	Balancing Portfolio in advance, so that whoever is causing the aggregate ramp issue can do what it wants. Where that is not possible, AEMO absorbs the impost on LFAS machines. However, in some cases, there are Facilities with very high ramp rates that are ramping in different ways, but they are generally the only generators ramping when this occurs, so AEMO modifies the ramp rates of those Facilities. Mr Fairclough clarified that AEMO has not been in a situation yet where five other machines are also ramping. Ms Laidlaw questioned whether an automated linear ramping process would assume that the Balancing Portfolio was being dispatched at 15 MW/minute or whether this does not matter. Mr Fairclough considered that it does not matter, as the quantities remain the same and it's just the ramp to get there that matters. If there was an aggregate ramp issue that could not be offset by the Balancing Portfolio and linear ramping was necessary, then every Facility would be dispatched linearly, this would be aggregated, and the Balancing Portfolio would ramp accordingly to offset the aggregate ramp. The ramp that the Balancing Portfolio must deal with will always be set using a manual process and not using LFAS. Ms Laidlaw questioned whether the Balancing Portfolio would be dispatched to a specific target, and if not, how AEMO would work out where to send the Balancing Portfolio if it was not using LFAS. Mr Fairclough considered that AEMO would not dispatch the Balancing Portfolio to a specific target but would move the Balancing Portfolio around during the Trading Interval to offset whatever remaining aggregate ramp existed. Mr Fairclough ~~was~~ said it was not clear ~~on~~ how it would be determined where to send the Balancing Portfolio but considered that controllers are trained to work this out. Mr Lei noted that the main benefit of a reduced gate closure is better forecasts and questioned whether a lot of benefits could be realised if just Synergy's gate closure was reduced without having all the cost associated with other changes to the BGC. Mr Lei considered that this would give Synergy time to consider more accurate information, as right now, they are locked out far ahead of time.	
8	**Quantifying Effects of Change** Ms Robins noted that there are three ways that the effects of the Rule Change Proposal could be assessed: estimation, market model simulation and time series forecasting. Time series forecasting is not really an option given that it requires looking backwards at what the outcome of the intervention was in the market. The main methods employed in the literature are estimation and market model simulation but there are problems with both, with the accuracy of the outputs being only as good as the accuracy of the	

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	inputs. With estimation, RCP Support would have to ask affected Market Participants and AEMO to approximate the possible effects of the intervention on themselves, but this approach is prone to bias. With market model simulation, the operation of the market can be simulated to assess outcomes at the various BGCs, but the Wholesale Electricity Market (**WEM**) uses a Balancing Portfolio and simulations are run on a facility basis, which reduces the accuracy of the outcomes. Market model simulation is also a costly and time-consuming process and the fact that resources are already being diverted into the Energy Transformation Strategy (**ETS**) reforms needs to be considered.	
9	**Forecasting Accuracy** Ms Robins noted that the main challenge in assessing the effects of changes to the BGC is dealing with the variability of supply (which depends on the available generation mix) and demand (which is increasingly fluctuating with an increasing penetration of solar PV), and the combined effect of these impacts on price, which is non-linear. Trying to predict how Market Participants will behave (i.e. whether they will position themselves at the floor so that they must run or position themselves at the ceiling rather than running at a lower clearing price) is also difficult. Ms Robins also highlighted that changes to the market would be made through the ETS reforms within the next two years, but any changes to implement new systems (such as an automatic linear ramping process) could not be made until the end of 2020.	
10-11	**Intended Approach** Ms Robins noted that RCP Support's intended approach is therefore not to use the production cost market model simulation or to attempt to predict what Market Participants might do in certain scenarios. Instead, its assessment will be based on Market Participant feedback from MAC meetings, workshops and the first period submissions. RCP Support will assess the proposal against the Wholesale and Balancing Market Objectives and the principles that underlie these objectives, and wherever possible will provide quantitative analyses to support its conclusions. Mr Fairclough considered that a dollar value for the costs associated with the Rule Change Proposal can be estimated but market simulation will be required to provide a dollar value estimate of the benefits from improved forecast accuracy. RCP Support agreed with Mr Fairclough, noting that this was the challenge that it was up against and questioned whether attendees had any suggestions for how the benefits of the Rule Change Proposal could be measured. No suggestions were put forward.	

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12	**Enhancement of Information used in Trading Decisions** Mr Sharafi noted that a major initiative to increase the accuracy of forecasting was to enable Non-Scheduled Generators to update their forecasts after BGC. Mr Sharafi questioned whether generators had made use of this initiative and noted that there are many things that can be done to increase the accuracy of the forecasts that are not currently being done. Ms Laidlaw noted that generators have not made use of this initiative and considered that an updated forecast after BGC serves little purpose in terms of accuracy in bidding, as Market Participants cannot update their Balancing Submissions after BGC. However, Ms Laidlaw considered that the updated forecast would give Market Participants a better indication of whether they are about to be started up, which is useful from an operational standpoint. Ms Laidlaw noted that a further option that may be useful operationally is to publish what is effectively the persistence forecast (i.e. the current output of Non-Scheduled Generators) closer to real time to allow Market Participants to take that into account when they look at the Forecast Balancing Merit Order (**BMO**) and see how much its likely to be affected. Ms Laidlaw considered that, at a certain stage, the persistence forecast is likely to be better than any forecast that a Market Participant is likely to get from Balancing Submissions. Mr Paul Arias noted that AEMO is updating forecasts more frequently now and suggested another option to increase the accuracy of information available to Market Participants would be for AEMO to re-run and publish the Forecast BMO every 5 minutes. Mr Arias considered that five or six IPPs may change their position slightly in a half hour period, and if one of the IPPs is marginal, a Market Participant may get caught out due to sudden changes in price (e.g. the price could suddenly double or halve).	
Extra Slide	**Implications of a Rolling Synergy Gate Closure for a Rolling LFAS Gate Closure** Ms Robins noted that, in the first workshop, there was general support for moving Synergy to a rolling gate closure and that an implication of moving Synergy to a rolling gate closure was that traders would need to monitor the Forecast BMO on a 24/7 basis to alleviate any risk of infeasible dispatch. However, when the possibility of moving the LFAS Gate Closure to a rolling gate closure was discussed, one of the Market Participants' concerns was that they may have to employ an additional trader because this would require 24/7 monitoring of the market. Additionally, Market Participants were concerned that there would be an increased risk that they would not realise that they had cleared in the LFAS Market, and therefore not reposition themselves accordingly in the Balancing Market, leading to penalties. Ms Robins	

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	questioned whether, if there was a trader already monitoring the Balancing Market because of a Synergy rolling gate closure, there was an option to also move to a rolling gate closure for the LFAS Market. Mr Lei considered that LFAS and Balancing monitoring are quite different because if you are enabled for LFAS you must make a second submission to reflect your enablement, whilst everyone has a standing submission to react in the Balancing Market so if Synergy changes its Balancing Submission the validity of everyone's Balancing Submissions are not affected, and Market Participants are not obliged to submit another Balancing Submission. Ms Laidlaw questioned how often participants in the LFAS Market have to change their Balancing Submissions following LFAS Gate Closure. Mr Arias considered that changes to the Balancing Submissions had to occur as soon as the participant knows that they are enabled and, if participants have a standing submission, then that would need to be tweaked three times a day or more, based on the mix and how much is enabled. Mr Huppatz considered that there are quite different drivers for LFAS and offered that participants have to see what is clearing in the market, which can change up to gate closure, so participants have to check that their Balancing Submissions have sufficient LFAS at the cap and floor pricing, to meet the obligation. Then, if you bid at the floor, the risk is that you are capped at the floor and it is not an economic run if you get put on. Mr Arias agreed, noting that with Balancing, if you are committed, you will guarantee a run level and price things so that if something is changed (e.g. someone else comes out) you can go either higher or lower in price. It is LFAS that leads to the obligation to then change bids in the Balancing Market. A rolling gate closure for Synergy doesn't necessarily require a review every half an hour, whereas if you go to a rolling LFAS Gate Closure, and you are participating or planning on bidding into that market, you will have to review it every half an hour because of the potential for non-compliance issues. Mr Arias considered that block bidding for LFAS was still the preferred option. In response to a question on whether a two-hour LFAS Horizon (instead of 6 or 4-hour blocks) would introduce too much risk, Mr Arias considered that the risk would be too great not to have a trader on duty. Ms Laidlaw questioned whether the LFAS Merit Order sometimes changes a participant's fundamental dispatch. Mr Arias considered that it can sometimes change the minimum commitment levels, as there are no guarantees on how much will be cleared in LFAS, if	

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	you clear at all. Mr Arias noted that not all machines can provide LFAS for their entire operational range. Ms Laidlaw questioned how often the results of the LFAS Market surprise Market Participants. Mr Arias responded that there are certain periods that may surprise you, and others which may be the same for weeks on end, but you would never run the risk of not checking. Mr Lei agreed, noting that the risk would be too high.	
13	**Next Steps** Ms Robins noted that the next steps will be to: • follow up on any outstanding data requests and complete any analyses (including establishing the requirement for linear ramping); • follow up on views expressed in workshops and conduct any one on one interviews requested by Market Participants; and • put the Draft Rule Change Report together as quickly as possible. The Chair asked whether attendees had any final questions or comments before wrapping up the workshop. Mr Huppatz offered that consideration needs to be given to linear ramping because of where the loads and dispatch are heading. Mr Huppatz considered that some form of linear ramping will be needed to ensure system security and that this probably informs the cost benefit analysis that RCP Support will undertake. Mr Quentin Jeay agreed and considered that it is better for the customer who pays for the cost of energy. Ms Robins cautioned that any linear ramping introduced prior to the ETS reforms would have to be devised, designed and implemented to fit on top of the existing system, and that, at this point, we don't have a good understanding of how linear ramping might work in practice in the existing system. Ms Robins noted that consideration also needs to be given to the question of whether removing the use of LFAS to address the aggregate ramp issue is reasonable given the need to maintain system security and reliability prior to the reforms. Mr Huppatz suggested that the LFAS enablement may be one of the considerations in a cost benefit analysis (i.e. you either go for linear ramping to manage system security or you review how much LFAS is enabled or utilised). Ms Robins noted that the suggestion that LFAS could not be used for instructed fluctuations had come from AEMO and that it was beyond the scope of RC_2017_02, which is about forecast accuracy. Mr Lei noted also that the introduction of linear ramping slated for the ETS reforms was based on a 5-minute dispatch cycle rather than the current ten-minute cycle, and that this would solve a lot of the aggregate ramping issue. Mr Lei questioned whether this	

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	process is just about solving the issues until the ETS reforms kick in, and it was agreed that this was the case. Ms Laidlaw highlighted the issues over the weekend of 12-13 October 2019, in which the WEM had too much generation and the Balancing Price went to the floor. Ms Laidlaw noted that in that situation, rooftop solar cannot be turned down, so generation must be turned down instead. Ms Laidlaw considered that the RTDE has a large dependency on the Balancing Portfolio and that there is a blurring between Balancing and LFAS, and questioned how AEMO will find the ramp necessary to offset the aggregate ramp of IPPs when it has to turn generation down in that scenario. Ms Laidlaw considered that these issues are far more urgent now and will probably have to be addressed before 2022, but are out of scope of RC_2017_02.	

RCP Rule Change Panel
Market Advisory Committee

Minutes

Meeting Title:	RC_2014_03: Administrative Improvements to the Outage Process - Workshop
Date:	25 October 2019
Time:	9:00 AM – 11:35 AM
Location:	Training Room 1, Albert Facey House 469 Wellington Street, Perth

Attendees	Representing	Comment
Stephen Eliot	RCP Support	
Jenny Laidlaw	RCP Support	
Natalie Robins	RCP Support	
Jake Flynn	Economic Regulation Authority (ERA)	
Dimitri Lorenzo	Bluewaters Power	
Paul Arias	Bluewaters Power	From 9:15 AM
Sam Lei	Alinta Energy	
Jacinda Papps	Alinta Energy	From 10:00 AM
Brad Huppatz	Synergy	
Kei Sukmadjaja	Western Power	To 11:25 AM
Dean Frost	Western Power	To 11:25 AM
Matthew Fairclough	AEMO	
Clayton James	AEMO	
Kang Chew	AEMO	From 9:10 AM

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4-6	**Removal of authorised notice requirement** Attendees agreed that while they would prefer to submit a Consequential Outage request directly into SMMITS than to submit a Forced Outage followed by an email to System Management, the direct entry option should not be implemented if it has a materially higher implementation cost.	
7-12	**Logging Forced and Consequential Outages in advance** In response to a question from Mr Matthew Fairclough, Ms Jenny Laidlaw clarified that a Market Generator who acted in	

	accordance with the triggering outage notifications issued by System Management would be deemed to be acting in compliance with the Market Rules and would not be exposed to a Forced Outage due to late changes to a triggering outage. Ms Laidlaw clarified that triggering outage notifications would not be used when the impact of network constraints on specific generators could not be predicted in advance. There was some discussion about the circumstances under which a generator that was subject to a regional cap would be eligible for a Consequential Outage, and the market impacts of unexpected changes to the output of large Non-Scheduled Generators due to network outages.	
13-14	**Logging Forced and Consequential Outages in advance – options for notification mechanism** Attendees discussed the three options for a triggering outage notification mechanism presented in the discussion slides. The following points were discussed: • Attendees raised no concerns about the increase in Dispatch Advisories (**DAs**) if Option 2 or Option 3 was implemented, noting that the format of the DAs could be standardised to help participants identify triggering outage notifications and manage them differently if they chose. • Mr Clayton James noted that one of the drawbacks of using the DA mechanism was that triggering outages can be approved several months before they commence. Using a DA in these situations would not provide participants with an ongoing view of upcoming triggering outages. Mr Paul Arias agreed that the timing of such notifications might be an issue for Bluewaters. Ms Laidlaw considered that an ideal solution would include both notifications and a reporting mechanism like that suggested by AEMO in Option 3. However, if a notification mechanism alone could provide the required information then it might be difficult to justify the additional costs of a PASA-like reporting mechanism. • Mr Brad Huppatz considered that the greater concern was about the timeliness of notifications relating to late changes and the obligations on Market Generators to respond. • Mr James and Mr Fairclough suggested the implementation of a combination of Options 2 and 3. This would involve AEMO issuing DAs as per Option 2 but also looking to include some of the information in the PASA tool that exists today. The combined mechanism could be reviewed after a period to assess its effectiveness. If Market Participants preferred the DAs the PASA information could be removed; alternatively, if the PASA reports were providing Market Participants with sufficient longer-term information then	

	AEMO would stop issuing DAs for triggering outages scheduled more than a week in the future. Mr Fairclough suggested that the Market Rules should be structured to allow AEMO to remove the requirement for longer-term DAs without the need for a rule change. Mr James suggested this could be done by specifying the notification mechanism in a Power System Operation Procedure. Ms Laidlaw noted that while both mechanisms would provide useful information to Market Participants, the information would probably have a slightly different structure and purpose, with the triggering outage notifications containing information that was unlikely to be included in a weekly PASA report. Ms Laidlaw noted that the Market Rules would not prevent AEMO from publishing any additional information on triggering outages that it considered would be useful to Market Participants. Attendees were generally supportive of the introduction of a triggering outage notification mechanism, and did not suggest any other implementation options.	
15-	**Logging Forced and Consequential Outages in advance – triggering outage notification content and timing** In response to a question from Mr James, Ms Laidlaw clarified that triggering outage notifications would only be issued for changes that affect the foreseeable constraints associated with the triggering outage. Mr Sam Lei and Mr Huppatz raised concerns about situations where generators are subject to large and unpredictable constraints during a network outage. Ms Laidlaw reiterated that triggering outage notifications would not be issued for this type of network outage. There was some discussion about the problems created by these outages and whether/when the impacts on generators may need to be planned more accurately to avoid unacceptable market volatility. There was some discussion about the factors that cause uncertainty about the impact of network outages on generators. Mr James noted that a Market Generator that was affected by a network outage in a way that could not be accurately foreseen would still be able to request a Consequential Outage ex-post. Ms Laidlaw agreed, but noted that some uncertainty existed around whether in future all such constraints would qualify as Consequential Outages. Attendees raised no concerns about the proposed triggering outage notification content and timing requirements.	

16-17	**Logging Forced and Consequential Outages in advance – revised proposal** Mr Fairclough and Mr James confirmed that AEMO would not incur any additional IT costs to allow ex-ante submission of Consequential Outage requests, regardless of the method chosen for the submission of these requests. Mr Arias sought clarification on what would happen if a Market Generator submitted an ex-ante Consequential Outage request that System Management failed to approve ex-ante, expressing concern that the request might lapse and need to be resubmitted. Mr Fairclough replied that System Management would always endeavour to approve such requests ex-ante if possible. Ms Laidlaw noted that changes to a triggering outage could cause a Consequential Outage request that had been approved ex-ante to become invalid. It was likely that to reduce implementation costs these Consequential Outage requests would be rejected, and the Market Generator would need to submit a new Consequential Outage request if necessary. It would be up to each Market Generator to decide whether the potential administrative overhead of having to submit a Consequential Outage request several times was warranted. Mr Lei noted that the revised proposal required Market Generators to update their Balancing Submissions to reflect triggering outage notifications "as far as possible", and asked for details of the relevant timeframes. Ms Laidlaw replied that the Amending Rules for Rule Change Proposal: Outage Planning Phase 2 – Outage Process Refinements (RC_2013_15) covered most of the relevant timing considerations (e.g. the need to allow at least 30 minutes to respond, and to allow for gate closure and machine start-up times). Attendees raised no concerns with: • the proposed requirement for Market Generators to take triggering outage notifications into account in their Balancing Submissions as far as possible; • the lack of any obligations to submit or approve Consequential Outage requests ex-ante; and • the proposed rules for the submission and approval of Consequential Outages set out in slide 17.	
18-19	**Logging Forced and Consequential Outages in advance – late changes to triggering outages** Attendees discussed the question of how much notice the market needs of late changes to triggering outages, including: • a delay to the start of a triggering outage; • the late cancellation of a triggering outage; and • early return to service from a triggering outage.	

	The following points were discussed: • Ms Laidlaw noted that a Scheduled Generator was expected to return to the Balancing Market as soon as practicable after a late notification of a change to a foreseeable constraint, taking response time, gate closure limits and start-up times into account as contemplated in new section 7A.2A (contained in the Amending Rules for RC_2013_15). However, if the notification occurred too late (e.g. after Balancing Gate Closure for the first affected Trading Interval), the market outcome might be the same as if the triggering outage had progressed as planned. • Mr Lei asked what the compliance implications would be if a Market Generator was emailed a DA at 5:00 AM advising of late changes to a foreseeable constraint, but failed to read the email or update its Balancing Submissions. Ms Laidlaw replied that Market Generators are already expected to monitor DAs and comply with any directions issued by System Management in a DA. • Ms Laidlaw noted that a Non-Scheduled Generator affected by a late change to a foreseeable constraint can be returned to service early without notice to the market because its capacity is not declared as unavailable in its Balancing Submissions (even if its forecast quantities are set to zero). There was some discussion about how System Management manages the removal from service and return to service of a Non-Scheduled Generator that is subject to a foreseeable constraint. • Ms Laidlaw questioned whether the Balancing Gate Closure restrictions that apply to Scheduled Generators returning to the Balancing Market should also apply to Non-Scheduled Generators in these situations. • In response to a question from Mrs Jacinda Papps, Ms Laidlaw confirmed that Market Generators are now allowed to update their Balancing Submissions after Balancing Gate Closure to provide a more accurate forecast of their expected output. Mrs Papps questioned whether a Market Generator could use this option to reflect the late removal of a foreseeable constraint on a Non-Scheduled Generator. Ms Laidlaw and Mr Arias considered that an update to reflect a cancelled outage was a slightly different concept and likely to have a greater impact than a normal forecast adjustment. • Mr Arias considered that the uncertainty imposed on Market Generators by unexpected changes to large Non-Scheduled Generator outages created risks that would be incorporated into market prices. Mr Fairclough suggested that this effect should be balanced against the Non-Scheduled Generators' ability to reduce the Balancing Price.	

	Mr James suggested that the situation might be different for notifications received before versus after Balancing Gate Closure. Mr Arias clarified that his comments only related to notifications received after Balancing Gate Closure. • Mr James noted that it was not simple for System Management to automate the release of a constraint after the end of a triggering outage. There was some discussion about how System Management manages the return to service of Non-Scheduled Generators (e.g. by limiting the ramp rates of Facilities to avoid Power System Security issues). Mr Fairclough confirmed that System Management generally releases the constraints on a Non-Scheduled Generator as soon as the relevant triggering outage has ended. There was further discussion about options to take market impacts as well as security concerns into account when managing the return of Non-Scheduled Generators from outages. Ms Laidlaw noted that questions about the minimum notice period for a late change to a triggering outage, and the return of a Non-Scheduled Generator to the Balancing Market after a late change to a foreseeable constraint, would be included in the call for further submissions on RC_2014_03.	
20	**Logging Forced and Consequential Outage in advance – triggering outage notifications for foreseeable constraints caused by Forced Outages** Attendees raised no concerns about the proposals to: • clarify the obligation on Rule Participants to notify System Management if they become aware that their Outage Facility will suffer a Forced Outage in the near future; and • provide System Management with an option to issue triggering outage notifications for network Forced Outages that it considers will have a material market impact. Mr Lei asked whether a Market Generator would be obliged to update the start and end times of its Consequential Outage to reflect when the triggering outage actually started and ended. Ms Laidlaw replied that if System Management issued a triggering outage notification updating a foreseeable constraint start or end time then the Market Generator may need to amend a previously submitted and/or approved Consequential Outage request. For this reason, Market Generators were likely to prefer to submit these requests after the foreseeable constraint had started, and possibly after it had ended.	
21-25	**Capacity-adjusted outage quantity calculation: RCOQ vs Capacity Credits** Mr Huppatz asked if a requirement to publish maximum site temperature data could be included in the Rule Change Proposal. At least some of this data was sourced from Western Power's SCADA systems and Mr Huppatz was unsure whether Synergy	

	was permitted access under the current confidentiality regime. Attendees generally agreed it would be helpful for a Market Generator to have access to this information for its Facilities. Attendees raised no concerns about: • the updated proposal to calculate capacity-adjusted outage quantities (as set out in slide 25); or • the proposed removal of the requirement to report Forced Outages for failures during an approved Commissioning Test.	
26-33	**Quantity of de-rating for Scheduled and Non-Scheduled Generators** Attendees raised no concerns with the proposed approach to reporting outage quantities for hybrid Non-Scheduled Generators (as set out in Option 4 on slide 31). Ms Laidlaw noted that the Rule Change Panel had reviewed the issue raised by Alinta during the second submission period for RC_2013_15 about the administrative burden of outage reporting for large Non-Scheduled Generators, but did not consider that an increase in the size of individual wind turbines warranted further changes to the materiality threshold. Mrs Papps reiterated her view that the outage reporting requirements for large Non-Scheduled Generators would be administratively burdensome. Ms Laidlaw noted that under the current Market Rules, Market Generators are required to schedule an outage if a single wind turbine is out of service. Attendees raised no other concerns with the updated proposal for recording outage quantities for Scheduled Generators and Non-Scheduled Generators set out in the appendix of the discussion slides.	
34	**Use of outage quantities in the Market Rules and clarification of timeframes** Ms Laidlaw noted that no material changes had been made to the proposal for the use of outage quantities in the Market Rules that was discussed at the 17 January 2018 workshop for RC_2014_03. Ms Laidlaw advised that the call for further submissions will include: • an updated table showing which outage quantities (unadjusted vs capacity-adjusted) will be used for which purposes; and • details of the proposed Planned Outage Rate, Forced Outage Rate and Equivalent Planned Outage Hours calculations. Attendees raised no concerns with the proposed approach to address the RC_2014_03 issues relating to the use of outage quantities in the Market Rules and the clarification of timeframes for providing outage information to System Management.	

36	**Outage definitions** Attendees raised no concerns about the intention to only consider the following outage definition issues as part of RC_2014_03: • Consequential Outages caused by non-Equipment List network equipment; • Forced Outages occurring during an approved Commissioning Test; and • (if required) expansion of the Consequential Outage definition to replace clauses 7A.2A.3 and 7A.2A.4.	
37	**Outage definitions – Consequential Outages caused by non-Equipment List network equipment** Attendees generally agreed that a Consequential Outage should be able to be caused by an outage of any equipment that is part of a registered Network. Mr Dean Frost considered that specifying details of secondary systems in the Equipment List could be very difficult and a more generic, less prescriptive approach should be taken. There was some discussion about previous events and whether they should qualify as Consequential Outage triggers. Attendees agreed that a recent SCADA system outage should be eligible, but did not agree that a recent bushfire event, where Balancing Portfolio Facilities were re-dispatched to avoid a concentration of generation near Southern Terminal, should qualify. Ms Laidlaw advised that RCP Support would seek legal advice on whether the Rule Change Panel could, as part of RC_2014_03, extend the definition of a Consequential Outage to cover an outage of any equipment forming part of a registered Network. There was some discussion about whether such a definition could prove ambiguous; however, Mr Fairclough considered that AEMO would be able to manage any potential ambiguity.	
38	**Outage definitions – replacement of clauses 7A.2A.3 and 7A.2A.4** Ms Laidlaw asked attendees to consider whether the definition of a Consequential Outage needed to be extended to cover the impacts of late changes to triggering outages, or whether new clauses 7A.2A.3 and 7A.2A.4 (updated to account for triggering outage notifications where necessary) were adequate. Ms Laidlaw noted that this question would be included in the call for further submissions. Mr Arias suggested that the late cancellation of a Consequential Outage that had been approved ex-ante could cause Net STEM Shortfall problems for a Scheduled Generator. Ms Laidlaw agreed to check whether there was a problem, and if there was how it could be resolved.	
40	**Timing requirements for Forced Outages in SMMITS**	

	Ms Laidlaw asked attendees for their views on: • what deadline (if any) should apply to AEMO changing its decision on a Consequential Outage request; and • whether a Market Generator should be able to apply to change a Forced Outage to a Consequential Outage after the 15-day limit, and if so, what process should be used. Attendees agreed that AEMO’s powers to convert a Consequential Outage to Forced Outage should not be subject to any specific deadline apart from the natural limit imposed by the settlement adjustment cycle. Mr Arias noted that a Market Generator may not have all the information it needs to support a Consequential Outage request by the 15-day submission limit. Mr Arias therefore considered that Market Generators should be able to submit Consequential Outage requests after this time, and that no specific deadline should apply (again except for the limit imposed by the settlement adjustment cycle). Mr Arias considered that notices of disagreement should not be used in these situations because they could lead to double handling of the relevant information. After some discussion, attendees expressed support for the following process: • If a Market Generator cannot obtain the information it needs to support a Consequential Outage request by the 15-day limit, then it reports a Forced Outage. • If the Market Generator subsequently obtains the required information, then it may submit a late Consequential Outage request to System Management. • System Management approves or rejects the Consequential Outage request as soon as practicable. • If System Management rejects the request, or is unable to process the request by the time of the last settlement adjustment, then the Forced Outage remains in effect. • If System Management approves the request, then the Forced Outage is deleted, and the updated outage details are used in the next settlement adjustment.	
41	**Timing requirements for Forced Outages in SMMITS – Scheduled Generators and Non-Scheduled Generators** Mr Lei and Mr Arias agreed that the current 15-day limit for the provision of final Forced Outage details in SMMITS was reasonable, because meter readings were usually available well before this time. Mr Huppatz considered that a 1 Business Day deadline for the initial entry of Forced Outage details in SMMITS would be quite onerous. Mr Huppatz acknowledged the value of providing information to the market about Forced Outages that were still ongoing, but questioned the urgency of updating SMMITS with	

	details of Forced Outages that have already ended, particularly for Non-Scheduled Generators. Mrs Papps considered that the requirement would also be quite onerous for the logging of Forced Outages for deviations from Dispatch Instructions. Mrs Papps did not think that Alinta would be able to meet a 1 Business Day deadline for these updates, which were currently submitted periodically in batches. In response to a question from Ms Laidlaw, Mr Arias advised that a Market Generator was usually aware that it had failed to comply with its Dispatch Instructions before it saw its meter readings, because it would have received an email about the deviation from System Management. Ms Laidlaw asked what problems a Market Generator might have reporting a larger, incomplete Forced Outage in SMMITS by the proposed deadline. Mrs Papps noted that sometimes it would be difficult on the first day of a Forced Outage to estimate how long the Facility would be unavailable. Ms Laidlaw agreed that it would need to be understood that the end time provided in the initial notification was only a 'best estimate'. Mr Lei suggested that in some circumstances a Market Generator might need a unit to cool down before the Market Generator could inspect it and form a reasonable estimate of its return to service time. Mr Huppatz agreed that it can take some time to determine the cause of a generator failure. Ms Laidlaw questioned whether a slightly longer deadline (e.g. 2-3 Business Days from the start of the outage) would make any significant difference to the accuracy of the initial estimates. In response to a comment from Mrs Papps, Ms Laidlaw clarified that the proposed requirement to keep a record of the reasons for changes to SMMITS outage records would only apply to changes made after the 15-day limit. Mrs Papps expressed interest in a discussion around whether there could be a materiality threshold applied to deviations from Dispatch Instructions. Mr Fairclough suggested that Tolerance Ranges fulfilled this function. Mrs Papps replied that Tolerance Ranges applied to System Management's reporting obligations rather than a Market Generator's compliance obligations. Ms Laidlaw agreed that there were problems with the current rules around Tolerance Ranges and deviations from Dispatch Instructions, and suggested that a Rule Change Proposal be submitted to address the issue. However, Ms Laidlaw noted that this issue was outside the scope of RC_2014_03. Mr Arias reiterated the concerns raised by other attendees about the administrative overheads of having to report Forced Outages for deviations from Dispatch Instructions every day. Ms Laidlaw advised that RCP Support would consider whether there was a	

	way to specify and apply a different reporting deadline to this type of Forced Outage.	
42	**Timing requirements for Forced Outages in SMMITS** Ms Laidlaw noted that RCP Support would work with AEMO to define the absolute deadline for late changes to an outage record in SMMITS, based on the deadlines for final Non-STEM settlement adjustments. Ms Laidlaw noted that the reasons for a late change to a Forced Outage record might include: • the replacement of the Forced Outage with a Consequential Outage; • late changes to meter readings; and • late notification of the need to report a Forced Outage following a compliance investigation. Attendees did not suggest any other reasons for late changes to a Forced Outage record. Attendees raised no concerns about: • the proposed requirement for Market Participants to keep records of the reasons for late changes to SMMITS outage records and to make those records available to AEMO or the ERA on request; or • the automated recalculation of Minimum Theoretical Energy Schedules to reflect late changes to outage records. Attendees did not identify any need to require Rule Participants to report Forced Outages of non-generator Outage Facilities in SMMITS prior to the current 15-day deadline.	
43-47	**Timing requirements for Consequential Outages in SMMITS** Attendees raised no concerns about the proposals for the management of Consequential Outages set out in slides 45-47. Attendees agreed that there was no need to specify a maximum duration for a Consequential Outage in SMMITS because Market Participants would have no problem determining when multiple Consequential Outage requests were needed to comply with the 15-day reporting deadline. Ms Laidlaw noted that the reasons for late changes to Consequential Outage records were similar to those for Forced Outages. Attendees did not suggest any additional reasons for late changes to Consequential Outage records.	
48	**Transitional requirements** Ms Laidlaw noted that the Rule Change Proposal was likely to require some transitional arrangements and RCP Support intended to seek input from AEMO on the transitional provisions that needed to be included in the Amending Rules.	

The workshop ended at 11:35 AM.

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 4: MAC Action Items

Meeting 2019_11_26

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
19/2019	The ERA to advise the MAC whether it intends to address the conflict between the Relevant Level Methodology and the early and conditional certification of Intermittent Generators as part of Rule Change Proposal RC_2019_03: Method used for the assignment of Certified Reserve Capacity for Intermittent Generators.	ERA	2019_09_03	**Open** The ERA is still considering its this matter and will advise the MAC in due course.
20/2019	AEMO to develop a Pre-Rule Change Proposal for AEMO's 'option 3' to address the North Country Spinning Reserve issue (as discussed at the 29 July 2019 MAC meeting), which is to include the removal of constrained off payments when the relevant generators are	AEMO	2019_09_03	**Closed** This matter was discussed under Agenda Item 8(b) at the MAC meeting on 15 October 2019, where it was agreed that AEMO would develop a Pre-Rule Change Proposal for options 2(a) and 2(b) for

Item	Action	Responsibility	Meeting Arising	Status
	constrained down to reduce the Spinning Reserve requirement, for presentation at the 26 November 2019 MAC meeting.			discussion at the 26 November 2019 MAC meeting.
21/2019	RCP Support to publish the minutes of the 3 September 2019 MAC meeting on the Rule Change Panel's (**Panel's**) website as final.	RCP Support	2019_10_15	**Closed** The minutes were published on the Panel's website on 15 October 2019.
22/2019	AEMO to develop a Pre-Rule Change Proposal for AEMO's 'option 2' (i.e. option 2a and 2b) to address the North Country Spinning Reserve issue, as discussed at the 29 July 2019 MAC meeting), for discussion at the 26 November 2019 MAC meeting.	AEMO	2019_10_15	**Open** This matter is discussed under Agenda Item 8(b).
23/2019	AEMO and RCP Support to discuss options for changes to the full runway Spinning Reserve cost allocation model to account for the largest single contingency comprising multiple generators, and to invite ERM Power, Alinta and Synergy to participate in those discussions.	AEMO/ RCP Support	2019_10_15	**Closed** AEMO and RCP Support met with ERM Power, Alinta, Synergy and Western Power on 13 November 2019. This matter is discussed further under Agenda Item 8(b).

RCP | Rule Change Panel
Market Advisory Committee

Agenda Item 5: MAC Market Rules Issues List Update

Meeting 2019_11_26

The latest version of the Market Advisory Committee (**MAC**) Market Rules Issues List (**Issues List**) is available in Attachment 1 of this paper.

The MAC maintains the Issues List to track and progress issues that have been identified by Wholesale Electricity Market (**WEM**) stakeholders. A stakeholder may raise a new issue for discussion by the MAC at any time by emailing a request to the MAC Chair.

Updates to the Issues List are indicated in red font, while issues that have been closed since the last publication are shaded in grey.

Recommendation:

RCP Support recommends that the MAC:

- note the updates to the Issues List;[1] and
- undertake the annual review of the Issues List.

Annual Review of the Issues List:

RCP Support has undertaken a review of the Issues List and has inserted preliminary comments (highlighted in blue) on some issues. The MAC is asked to review the Issues List and RCP Support's preliminary comments; and to agree on what to do for each issue.

[1] Issues 57-62 have been added to Table 4 – Issues on Hold. These are the outage-related issues discussed by the MAC under Agenda Item 5 on 15 October 2019.

Agenda Item 5 – Attachment 1 – MAC Market Rules Issues List

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
31	Synergy November 2018	**LFAS Report** Under clauses 7A.2.9(b) and 7A.2.9(c) of the Market Rules, Synergy is obligated to compile and send the LFAS weekly report to AEMO based on the LFAS data for each Trading Interval supplied to Synergy by System Management. Given that System Management is now part of AEMO, it seems reasonable to remove this obligation on Synergy to reduce administrative burden. This rule change supports Wholesale Market Objective (a).	**Panel rating:** Low, but OK to progress using the Fast Track Rule Change Process **MAC ratings:** Low: Alinta, Bluewaters Medium: Geoff Gaston, AEMO High: Peter Huxtable **Status:** This issue has not been progressed. Synergy should advise whether this is still an issue and whether it plans to develop and submit a Rule Change Proposal.
45	AEMO May 2018	**Transfer of responsibility for setting document retention requirements** AEMO suggested that responsibility for setting document retention requirements (clauses 10.1.1 and 10.1.2 of the Market Rules) should move from AEMO to the ERA. AEMO considers that it is not the best entity to hold this responsibility as it no longer maintains the broader market development and compliance functions of the IMO.	**Panel rating:** Low **MAC ratings:** Low **Status:** Waiting on the ERA to provide its position on the proposal, but this is a low priority issue for the ERA. The ERA should provide its views on whether it believes it should be responsible for setting document retention requirements.

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
46	AEMO May 2018	**Transfer of responsibility for setting confidentiality statuses** AEMO suggested that responsibility for setting confidentiality statuses (clauses 10.2.1 and 10.2.3 of the Market Rules) should move from AEMO to the ERA. AEMO considers that it is not the best entity to hold this responsibility as it no longer maintains the broader market development and compliance functions of the IMO.	**Panel rating:** Low **MAC ratings:** Low **Status:** Waiting on the ERA to provide its position on the proposal, but this is a low priority issue for the ERA. The ERA should provide its views on whether it believes it should be responsible for setting confidentiality statuses.
47	AEMO September 2018	**Market Procedure for conducting the Long Term PASA (clause 4.5.14)** The scope of this procedure currently includes describing the process that the ERA must follow in conducting the five-yearly review of the Planning Criterion and demand forecasting process. AEMO considers that its Market Procedure should not cover the ERA's review, and the ERA should be able to independently scope the review. As such, AEMO recommends removing this requirement from the head of power in clause 4.5.14 of the Market Rules.	**Panel rating:** Low **MAC ratings:** Low **Status:** This issue has not been progressed. RCP Support recommends retaining this issue.
52	MAC February 2019	**North Country Spinning Reserve** How should potential future scenarios be managed where multiple generating units that are connected to the same line constitute the largest credible contingency, without imposing excessive constraint payment costs on Market Customers?	**Panel rating:** TBD **MAC ratings:** High **Status:**

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
			The MAC discussed this issue at its meetings on 11 June and 29 July 2019. AEMO has proposed three options to address this issue. The MAC further discussed this issue at its meeting on 3 September 2019, where the MAC supported option 3. AEMO agreed to develop a Pre-Rule Change Proposal for option 3 for presentation to the MAC at its meeting on 26 November 2019. The MAC further discussed this issue at its meeting on 15 October 2019, where the MAC changed its view to instead support option 2. AEMO, RCP Support, ERM Power, Alinta and Synergy met on 13 November 2019; and AEMO, RCP Support and EPWA met on 18 November 2019 to discuss the North Country Spinning Reserve issue. AEMO is to develop a Pre-Rule Change Proposal for option 2 for presentation to the MAC at its meeting on 26 November 2019 – see Agenda Item 8(b).
53	Alinta February 2019	**TES Recalculation** Alinta is seeking a rule change to allow the recalculation of TES after the current 15 Business Day deadline.	**Panel rating:** Low **MAC ratings:** Low **Status:**

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
			Pre-Rule Change Proposal: Administrative Improvements to Settlement (RC_2019_04) includes changes to allow AEMO to recalculate TES values after the 15 Business Day deadline if it identifies an error in the input values. The MAC discussed RC_2019_04 at its meeting on 15 October 2019, where the MAC confirmed that it did not consider there was any need for additional changes to the calculation of TES beyond those proposed in RC_2019_04 (e.g. broader changes to require recalculation of values using interval meter data). The MAC is asked to consider whether Issue 53 should be closed following the formal submission of RC_2019_04 into the rule change process.
55	MAC April 2019	**Conflict between Relevant Level Methodology and the early and conditional certification of Intermittent Generators** There is a conflict between the current and proposed Relevant Level Methodologies and the early and conditional certification of new Intermittent Generators, because the methodologies depend on information that is not available before the normal certification time for a Reserve Capacity Cycle.	**Panel rating:** TBD **MAC ratings:** Low **Status:** On 15 August 2019, Mr Maticka advised RCP Support that AEMO has revised its position and is now of the view that there is an opportunity as part of RC_2019_03 to remove Clause 4.28C.7 that relates to Early Certification of Reserve Capacity (**CRC**).

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
			The draft proposal states that AEMO "must reject the early certification application if it has cause to believe that it cannot reliably set the Early CRC…"; otherwise, AEMO must set Early CRC within 90 days of receiving the application. It appears that it is almost certain that AEMO cannot reliably set the Early CRC for an early certification application if an intermittent Facility nominates to use clause 4.11.2(b) for the assessment. This is because: • An early certification application may be submitted at any time before 1 January of Year 1 of the Reserve Capacity Cycle to which the application relates [clause 4.28C.2]. • This means that when AEMO receives an application under 4.11.2(b), it can't calculate a reliable Relevant Level value for the Facility, as it is not certain: o which Scheduled Generators, DSPs, and Non-Scheduled Generators would apply for certification; or o what level of CRC would be assigned to these Scheduled Generators and DSPs.

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
			AEMO also stated that: • Neither a complete set of system demand and Facility actual meter data is available nor are the expected capacity estimates of new Candidate Facilities. • It almost implies that in fact only Scheduled Generators can apply and be certified for Early Certification. Noting an application of this nature has not been provided in the past years, AEMO suggests removal of this clause completely. The MAC discussed this issue at its meeting on 3 September 2019 where it was noted that the issue could be addressed as a standalone Rule Change Proposal or as part RC_2019_03. The ERA is considering whether it wants to address the issue as part of RC_2019_03, and if not, then RCP Support will bring the issue back to the MAC for further discussion The ERA should form a view on whether it will progress issue 55 under RC_2019_03.
56	Perth Energy July 2019	**Issues with Reserve Capacity Testing** • Market Generators that fail a Reserve Capacity Test may prefer to accept a small shortfall in a test (and a corresponding reduction in their Capacity Credits) than to run a second test.	**Panel rating:** TBD **MAC ratings:** TBD **Status:**

Table 1 – Potential Rule Change Proposals			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		• There is a discrepancy between the number of Trading Intervals for self-testing vs. AEMO testing. • There is ambiguity in the timing requirements for a second test when the relevant generator is on an outage. • There is ambiguity on the number of Capacity Credits that AEMO is to assign when certain test results occur.	Perth Energy has indicated that it will develop a Pre-Rule Change Proposal for consideration by the MAC. RCP Support recommends retaining this issue.

Notes:

- The Potential Rule Change Proposals are well-defined issues that could be addressed through development of a Rule Change Proposal.
- If the MAC decides to add an issue to the Potential Rule Change Proposals list, then RCP Support will seek a preliminary urgency rating from MAC members/observers and from the Rule Change Panel (**Panel**) and will include this information in the list.
- Potential Rule Change Proposals will be closed after a Pre-Rule Change Proposal is presented to the MAC or a Rule Change Proposal is submitted to the Panel.

Table 2 – Broader Issues			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
1	Shane Cremin November 2017	**IRCR calculations and capacity allocation** There is a need to look at how IRCR and the annual capacity requirement are calculated (i.e. not just the peak intervals in summer) along with recognising behind-the-meter solar plus storage. The incentive should be for retailers (or third-party providers) to reduce their dependence on grid supply during peak intervals, which will also better reflect the requirement for conventional 'reserve capacity' and reduce the cost per kWh to consumers of that conventional 'reserve capacity'.	To be considered in the preliminary review of the Reserve Capacity Mechanism. See the comments in Table 3.
2	Shane Cremin November 2017	Allocation of market costs – who bears Market Fees and who pays for grid support services with less grid generation and consumption?	To be considered in the preliminary reviews of behind-the-meter issues and the basis for allocation of Market Fees. See the comments in Table 3.
3	Shane Cremin November 2017	Penalties for outages.	To be considered in the preliminary review of the Reserve Capacity Mechanism. See the comments in Table 3.
4	Shane Cremin November 2017	Incentives for maintaining appropriate generation mix.	To be considered in the preliminary review of the Reserve Capacity Mechanism. See the comments in Table 3.
9	Community Electricity November 2017	Improvement of AEMO forecasts of System Load; real-time and day-ahead	To be considered in the preliminary review of forecast quality. See the comments in Table 3.

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

Table 2 – Broader Issues			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		receive from the reform. This is expected to increase the visibility of (and therefore incentivise) prudence and accountability when it comes to deciding the need and scope of the reform. Recommendations: to review the Market Fees structure including the cost recovery mechanism for a reform program. The cost saving from improved economic efficiency can be passed on to the end consumers, hence promoting the Wholesale Market Objectives.	
30	Synergy November 2017	**Reserve Capacity Mechanism** Synergy would like to propose a review of Market Rules related to reserve capacity requirements and reserve capacity capability criteria to ensure alignment and consistency in determination of certain criteria. For instance: • assessment of reserve capacity requirement criteria, reserve capacity capability and reserve capacity obligations; • IRCR assessment; • Relevant Demand determination; • determination of NTDL status; • Relevant Level determination; and • assessment of thermal generation capacity. The review will support Wholesale Market Objectives (a) and (d).	To be considered in the preliminary review of the Reserve Capacity Mechanism. See the comments in Table 3.

Table 2 – Broader Issues			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
35	ERM Power November 2017	**BTM generation and apportionment of Market Fees, ancillary services, etc.** The amount of solar PV generation on the system is increasing every year, to the point where solar PV generation is the single biggest unit of generation on the SWIS. This category of generation has a significant impact on the system and we have seen this in terms of the daytime trough that is observed on the SWIS when the sun is shining. The issue is that generators that are on are moving around to meet the needs of this generation facility but this generation facility, which could impact system stability, does not pay its fair share of the costs of maintaining the system in a stable manner. That is, they are not the generators that receive its fair apportionment of Market Fees and pay any ancillary service costs but yet they have absolute freedom to generate into the SWIS when the fuel source is available. There needs to be equity in this equation.	To be considered in the preliminary reviews of behind-the-meter issues and the basis for allocation of Market Fees. The MAC recognised that the Minister has commenced work on BTM issues and flagged that issue 35 should be considered as part of the Energy Transformation Strategy. See the comments in Table 3.
39	Alinta Energy November 2017	**Commissioning Test Process** The commissioning process within the Market Rules and PSOP works well for known events (i.e. the advance timings of tests). However, the Market Rules and PSOP do not work for close to real time events. There is limited flexibility in the Market Rules and PSOP to deal with the practical and operational realities of commissioning facilities. The Market Rules and PSOP require System Management to approve a Commissioning Test Plan or a revised Commissioning Test Plan by 8:00 AM on the Scheduling Day on which the Commissioning Test Plan would apply.	To be considered in the preliminary review of the Commissioning Tests. See the comments in Table 3.

Table 2 – Broader Issues			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		If a Market Participant cannot conform to its most recently approved Commissioning Test Plan, the Market Participant must notify System Management; and either: • withdraw the Commissioning Test Plan; or • if the conditions relate to the ability of the generating Facility to conform to a Commissioning Test Schedule, provide a revised Commissioning Test Plan to System Management as soon as practicable before 8:00 AM on the Scheduling Day prior to the commencement of the Trading Day to which the revised Commissioning Test Plan relates. **Specific Issues:** This restriction to prior to 8:00 AM on the Scheduling Day means that managing changes to the day of the plan are difficult. Sometimes a participant is unaware at that time that it may not be able to conform to a plan. Amendments to Commissioning Tests and schedules need to be able to be dealt with closer to real time. **Examples for improvements are:** • allowing participants to manage delays to the start of an approved plan; and • allowing participants to repeat tests and push the remainder of the Commissioning Test Plan out. Greater certainty is needed for on the day changes (i.e. there is uncertainty as to what movements/timing changes acceptable within the "Test Window" i.e. on the day).	

		Wholesale Market Objective Assessment: A review of the Commissioning Test process, with a view to allowing greater flexibility to allow for the technical realities of commissioning, will better achieve: • Wholesale Market Objective (a): o Allowing generators greater flexibility in undertaking commissioning activities will allow the required tests to be conducted in a more efficient and timely manner, which should result in the earlier availability of approved generating facilities. This contributes to the efficient, safe and reliable production of energy in the SWIS. o Productive efficiency requires that demand be served by the least-cost sources of supply, and that there be incentives for producers to achieve least-cost supply through a better management of cost drivers. Allowing for a more efficient management of commissioning processes, timeframes and costs in turn promotes the economically efficient production and supply of electricity. • Wholesale Market Objective (b): improvements to the efficiency of the Commissioning Test process may assist in the facilitation of efficient entry of new competitors. • Wholesale Market Objective (d): o Balancing appropriate flexibility for generators with appropriate oversight and control for System Management should ensure that the complex task of commissioning is not subject to unnecessary red tape, adding to the cost of projects. This contributes to the achievement of Wholesale Market Objective (d) relating to the long-term cost of electricity supply.	

Table 2 – Broader Issues			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		o Impacts on economic efficiency and efficient entry of new competitors (as outlined above) will potentially lead to the minimisation of the long-term cost of electricity supplied.	

Notes:

- Some issues require further discussion/review before specific Rule Change Proposals can be developed. For these issues, the MAC will:
  - o group the issues together where appropriate;
  - o determine the order of priority for the grouped Broader Issues;
  - o conduct preliminary reviews to scope out the Broader Issues; and
  - o refer the Broader Issues to the appropriate body for consideration/development.
- RCP Support will aim to schedule preliminary reviews at the rate of one per MAC meeting, unless competing priorities prevent this.
- Broader Issues will be closed (or moved onto another sub-list) following the completion of the relevant preliminary review and any agreed follow-up discussions on the issue.
- The current list of preliminary reviews is shown in Table 3.

Table 3 – Preliminary Reviews	
Review	**Status**
(1) Review of roles in the market	**Issues:** 11 and 12. **Status:** Review deferred until Issues 11 and 12 are reopened following completion of the Energy Transformation Strategy. **Status:** Preliminary discussion is not yet scheduled. The MAC is asked to provide feedback on whether a preliminary discussion of this issue is still worthwhile, and if so, whether it still number (1) in its order of priority.
(2) Behind-the-meter issues	**Issues:** 2, 16, 35. **Status:** Preliminary discussion is not yet scheduled. RCP Support notes that EPWA has currently working on its DER Roadmap, which will address behind-the-meter issues (amongst other things). RCP Support recommends that the MAC defer a preliminary discussion of behind-the-meter issues until the DER Roadmap is published and then consider whether a discussion is still worthwhile.
(3) Forecast quality	**Issues:** 9. **Status:** Preliminary discussion is not yet scheduled. The MAC is asked to provide feedback on whether a preliminary discussion of this issue is still worthwhile, and if so, whether it still number (3) in its order of priority.
(4) Commissioning Tests	**Issues:** 39. **Status:** Preliminary discussion is not yet scheduled. The MAC is asked to provide feedback on whether a preliminary discussion of this issue is still worthwhile, and if so, whether it still number (4) in its order of priority.

Table 3 – Preliminary Reviews	
Review	**Status**
(5) The basis of allocation of Market Fees	**Issues:** 2, 16, 23 and 35. **Status:** Preliminary discussion is not yet scheduled. The MAC is asked to provide feedback on whether a preliminary discussion of this issue is still worthwhile, and if so, whether it still number (5) in its order of priority.
(6) The Reserve Capacity Mechanism (excluding the pricing mechanism)	**Issues:** 1, 3, 4, and 30. **Status:** Preliminary discussion is not yet scheduled. The MAC is asked to provide feedback on whether a preliminary discussion of this issue is still worthwhile, and if so, whether it still number (6) in its order of priority.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
7	Community Electricity November 2017	Improved definition of the quantity of LFAS (a) required and (b) dispatched.	On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020), with potential input from work on RC_2017_02: Implementation of 30-Minute Balancing Gate Closure. RCP Support recommends leaving issue 7 on hold.
10	AEMO November 2017	Review of participant and facility classes to address current and looming issues, such as: • incorporation of storage facilities; • distinction between non-scheduled and semi-scheduled generating units; • reconsideration of potential for Dispatchable Loads in the future (which were proposed for removal in RC_2014_06); • whether to retain Interruptible Loads or to move to an aggregated facility approach (like Demand Side Programmes); and • whether to retain Intermittent Loads as a registration construct or to convert to a settlement construct. Would support new entry, competition and market efficiency; particularly supporting the achievement of Wholesale Market Objectives (a) and (b).	On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). Treatment of storage facilities was considered under the preliminary review of the treatment of storage facilities in the market. RCP Support recommends leaving issue 10 on hold.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
11	AEMO November 2017	**Whole-of-system planning oversight:** As explained in AEMO's submission to the ERA's review of the WEM, AEMO considers the necessity of the production of an annual, independent Integrated Grid Plan to identify emerging issues and opportunities for investment at different locations in the network to support power system security and reliability. This role would support AEMO's responsibility for the maintenance of power system security and will be increasingly important as network congestion increases and the characteristics of the power system evolve in the course of transition to a predominantly non-synchronous future grid with distributed energy resources, highlighting new requirements (e.g. planning for credible contingency events, inertia, and fast frequency response). This function would support the achievement of power system security and reliability, in line with Wholesale Market Objective (a).	This issue was initially flagged for consideration as part of the preliminary review of roles in the market. However, ETIU has advised that the issue will be covered as part of the Energy Transformation Strategy, so the issue has been put on hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). ETIU is currently developing a Whole of System Plan to be delivered to Government and published in mid-2020. ETIU has indicated that the intent is to develop and publish updated Whole of System Plans on an ongoing, regular basis; but RCP Support is not aware of who will develop these plans or how often they will be published. RCP Support recommends leaving issue 11 on hold pending publication of the first Whole of System Plan and clarification of the process to develop and publish ongoing plans.
12	AEMO November 2017	**Review of institutional responsibilities in the Market Rules.** Following the major changes to institutional arrangements made by the Electricity Market Review, a secondary review is required to ensure that tasks remain with the right organisations, e.g. responsibility for setting confidentiality status (clause 10.2.1),	Potential changes to responsibilities for setting document retention requirements and confidentiality statuses have been listed as Potential Rule Change Proposals (issues 45 and 46). Potential changes to clause 4.5.14

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		document retention (clause 10.1.1), updating the contents of the market surveillance data catalogue (clause 2.16.2), content of the market procedure under clause 4.5.14, order of precedence of market documents (clause 1.5.2). This will promote efficiency in market administration, supporting Wholesale Market Objectives (a) and (d).	have also been listed as a Potential Rule Change Proposal (issue 47). ~~The PUO~~ EPWA has advised that the remaining issues will be covered as part of the Energy Transformation Strategy, so the remaining issues have been put on hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). RCP Support recommends leaving issue 12 on hold.
14/36	Bluewaters and ERM Power November 2017	**Capacity Refund Arrangements:** The current capacity refund arrangement is overly punitive as Market Participants face excessive capacity refund exposure. This refund exposure is well more than what is necessary to incentivise the Market Participants to meet their obligations for making capacity available. Practical impacts of such excessive refund exposure include: • compromising the business viability of some capacity providers - the resulting business interruption can compromise reliability and security of the power system in the SWIS; and • excessive insurance premiums and cost for meeting prudential support requirements. Bluewaters recommended imposing seasonal, monthly and/or daily caps on the capacity refund. Bluewaters considered that	On 29 May 2018, the MAC agreed to place this issue on hold for 12 months (until June 2019) to allow time for historical data on dynamic refund rates to accumulate. On 29 July 2019, the MAC agreed that this issue has a low priority and should remain on hold for another 12 months. RCP Support recommends leave issue 14/36 on hold for further consideration in July 2020.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		reviewing capacity refund arrangements and reducing the excessive refund exposure is likely to promote the Wholesale Market Objectives by minimising: • unnecessary business interruption to capacity providers and in turn minimising disruption to supply availability; which is expected to promote power system reliability and security; and • unnecessary excessive insurance premium and prudential support costs, the saving of which can be passed on to consumers.	
17	Bluewaters November 2017	Under clause 3.21.7 of the Market Rules, a Market Participant is not allowed to retrospectively log a Forced Outage after the 15-day deadline; even if the Market Participant is subsequently found to be in breach of the Market Rules for not logging the Forced Outage on time. This can result in under reporting of Forced Outages, and as a consequence, use of incorrect information used in WEM settlements. Bluewaters recommend a rule change to enable Market Participants to retrospectively log a Forced Outage after the 15-day deadline. If a Market Participant is found to be in breach of the Market Rules by not logging the Forced Outage by the deadline, it should be required to log the outage. Accurately reporting outages will enable the WEM to function as intended and will help meet the Wholesale Market Objectives.	On hold pending a final decision on RC_2014_03: Administrative Improvements to the Outage Process. RCP Support recommends leaving issue 12 on hold pending a final decision on RC_2014_03.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
18	Bluewaters November 2017	The Spinning Reserve procurement process does not allow Market Participants to respond to the draft margin values determination by altering its Spinning Reserve offer. Bluewaters recommended amending the Market Rules to allow Market Participants to respond to the draft margin values determination by altering its Spinning Reserve offer. Allowing a Market Participant to respond to the draft margin values determination, can serve as a price signal to enable a price discovery process for Spinning Reserve capacity. This is expected to lead to a more efficient economic outcome and in turn promote the Wholesale Market Objectives.	On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). RCP Support recommends leaving issue 18 on hold.
19	Bluewaters November 2017	The Spinning Reserve margin values evaluation process is deficient for the following reasons: • shortcomings in the process for reviewing assumptions; • inability to shape load profile; • lack of transparency: (a) modelling was a "black box"; (b) confidential information limits stakeholders' ability to query the results; and • lack to retrospective evaluation of spinning reserve margin values. As a result, the margin values have been volatile, potentially inaccurate and not verifiable.	On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). Also, AEMO and the ERA to consider whether any options exist to improve transparency of the current margin values process. RCP Support recommends leaving issue 19 on hold.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		Recommendation: conduct a review on the margin values evaluation process and propose rule changes to address any identified deficiencies. Addressing the deficiencies in the margin values evaluation process can promote the Wholesale Market Objectives by enhancing economic efficiency in the WEM. This can be achieved through: • promoting transparency – better informed Market Participants would be able to better respond to Spinning Reserve requirement in the WEM; and • allowing a better-informed margin values determination process, which is likely to give a more accurately priced margin values to promote an efficient economic outcome.	
22	Bluewaters November 2017	Prudential arrangement design issue: clause 2.37.2 of the Market Rules enables AEMO to review and revise a Market Participant's Credit Limit at any time. It is expected that AEMO will review and increase Credit Limit of a Market Participant if AEMO considers its credit exposure has increased (for example, due to an extended plant outage event). In response to the increase in its credit exposure, clause 2.40.1 of the Market Rules and section 5.2 of the Prudential Procedure allow the Market Participant to make a voluntary prepayment to reduce its Outstanding Amount to a level below its Trading Limit (87% of the Credit Limit). Under the current Market Rules and Prudential Procedure, AEMO can increase the Market Participant's Credit Limit (hence	On hold pending AEMO's proposed review of its process for Credit Limit determination. AEMO should advise on the status of its review.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		increasing its prudential support requirement) despite that a prepayment has already been paid (it is understood that this is AEMO's current practice). The prepayment would have already served as an effective means to reduce the Market Participant's credit exposure to an acceptable level. Increasing the Credit Limit in addition to this prepayment would be an unnecessary duplication of prudential requirement in the WEM. This unnecessary duplication is likely to give rise to higher-than-necessary prudential cost burden in the WEM; which creates economic inefficiency that is ultimately passed on the end consumers. Recommendation: amend the Market Rules and/or procedures to eliminate the duplication of prudential burden on Market Participants. The resulting saving from eliminating this unnecessary prudential burden can be passed on to end consumers. This promotes economic efficiency and therefore the Wholesale Market Objectives.	
27/54	Kleenheat November 2017 MAC August 2018	Review what should constitute a Protected Provision of the Market Rules, to provide greater clarity over the role of the Minister for Energy. A review of the Protected Provisions in the Market Rules is required to identify any that they no longer need to be Protected Provisions. This is because shifting the rule change function to the	On hold pending the outcome of a ~~PUO~~ EPWA review of the current Protected Provisions in the Market Rules, with timing dependent on Energy Transformation Strategy. The current list of Protected Provisions creates inefficiencies by adding unnecessary

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		Panel has removed some of the potential conflicts of interest that led to the original classification of some Protected Provisions.	approval steps to the process, which lengthens the process and adds costs, particularly for the Minister. RCP Support recommends that EPWA and RCP Support: • develop principles for identifying which rules should be Protected Provisions for discussion and agreement with the MAC; and • apply the agreed principles to the Market Rules to develop a recommended revised list of Protected Provisions. The MAC can then consider steps to develop and submit a Rule Change Proposal to revise the Protected Provisions.
28	Kleenheat November 2017	Appropriate rule changes to allow for battery storage. Consultation to decide how the batteries will be treated and classified as generators or not, whether batteries can apply for Capacity Credits and the availability status when the batteries are charging.	On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). RCP Support recommends leaving issue 28 on hold.
33	ERM Power November 2017	**Logging of Forced Outages** The market systems do not currently allow Forced Outages to be amended once entered. This can have the distortionary effect of participants not logging an Outage until it has absolute certainty that the Forced Outage is correct, hence participants could take up to 15 days to submit its Forced Outages.	On hold pending a final decision on RC_2014_03: Administrative Improvements to the Outage Process. RCP Support recommends leaving issue 33 on hold pending a final decision on RC_2014_03.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		If a participant could cancel or amend its Forced Outage information, it will likely provide more accurate and transparent signals to the market of what capacity is really available to the system. This should also assist System Management in generation planning for the system.	
42	ERA November 2017	**Ancillary Services approvals process** Clause 3.11.6 of the Market Rules requires System Management to submit the Ancillary Services Requirements in a report to the ERA for audit and approval by 1 June each year, and System Management must publish the report by 1 July each year. The ERA conducted this process for the first time in 2016/17. In carrying out the process it became apparent that: • there is no guidance in the rules on what the ERA's audit should cover, or what factors the ERA should consider in making its determination on the requirements; • there are no documented Market Procedures setting out the methodology for System Management to determine the ancillary service requirements (the preferable approach would be for the methodologies to be documented in a Market Procedure, and for the ERA to audit whether System Management has followed the procedure); • the timeframe for the ERA's audit and approval process (less than 1 month) limits the scope of what it can achieve in its audit;	On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). RCP Support recommends leaving issue 42 on hold.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		• the levels determined by System Management are a function of the Ancillary Service standards, but the standards themselves are not subject to approval in this process; and • the value of the audit and approval process is limited because System Management has discretion in real time to vary the levels from the set requirements. The question is whether the market thinks this approvals process is necessary/will continue to be necessary (particularly in light of co-optimised energy and ancillary services). If so, then the issues above will need to be addressed, to reduce administrative inefficiencies and, if more rigour is added to the process, provide economic benefits (Wholesale Market Objectives (a) and (d)).	
49	MAC November 2018	Should the method used to calculate constrained off compensation be amended to better reflect the actual costs incurred by Market Generators?	The MAC agreed to include this issue in the Issues List and place it on hold until a decision is made on RC_2018_07, and if the Rule Change Proposal is approved, the changes have been in place for 12 months. The Amending Rules from RC_2018_07 commenced on 1 July 2019. RCP Support recommends that issue 49 remain on hold until 1 July 2020 to see if the issue requires further consideration.
50	MAC November 2018	Should the Minimum STEM Price (currently -$1,000/MWh) be increased to reduce the potential magnitude of constrained off compensation (e.g. by restoring the former practice of setting the	The MAC agreed to include this issue in the Issues List and place it on hold pending the outcomes of the ERA's next review of the

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		Minimum STEM Price to the Maximum STEM Price multiplied by -1)	methodology for setting the Energy Price Limits under clause 2.26.3 of the Market Rules. RCP Support recommends closing this issue as it will be addressed by RC_2019_05, which was submitted by Synergy on 25 October 2019.
51	MAC November 2018	There is a need to provide Market Customers with timely advance notice of their upcoming constraint payment liabilities.	The MAC agreed to place this issue on hold pending implementation of AEMO's proposed changes to the Outstanding Amount calculation in 2019. AEMO should advise on the status of its implementation process.
53	MAC August 2018	MAC members have identified the following issues with the provisions relating to generator models that were Gazetted by the Minister on 30 June 2017 in the *Wholesale Electricity Market Rules Amending Rules 2017 (No. 3)*: • The provisions allow for System Management, where it deems that the performance of a Generator does not conform to its models, to request updated models from Western Power and constrain the output of the Generator until these were provided, placing the Generator on a new type of Forced Outage and making it liable for Capacity Cost Refunds. • Western Power is only required to comply with a request from System Management for updated models "as soon as	On hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020). RCP Support recommends leaving issue 53 on hold.

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		reasonably practicable", leaving a Market Generator potentially subject to a Forced Outage for an extended period with no control over the situation. • The generator model information is assigned a confidentiality status of System Management Confidential, so that System Management is not permitted under the Market Rules to tell the Network Operator what model information it needs or explain the details of its concerns to the Market Generator.	
57	MAC October 2019	**Identification of services subject to outage scheduling** The Market Rules do not clearly define the 'services' that should be subject to outage scheduling (e.g. what services are provided by different items of network equipment, Intermittent Load facilities, dual-fuel Scheduled Generators, etc), and how the 'availability' of these services should be measured for each Outage Facility. This can lead to ambiguity about what constitutes an Outage for certain Outage Facilities. Additionally, if a Facility or item of network equipment can provide multiple services that require outage scheduling, then this concept should be clearly reflected in the Market Rules. The Amending Rules for RC_2013_15 clarified that a Scheduled Generator or Non-Scheduled Generator that is subject to an Ancillary Service Contract is required to schedule outages in respect of both sent out energy and each contracted Ancillary Service but did not seek to address the broader issue. (See section 7.2.2.5 of the Final Rule Change Report for RC_2013_15.)	The MAC agreed that this issue should be placed on hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020).

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
58	MAC October 2019	**Outage scheduling for dual-fuel Scheduled Generators** ‘0 MW’ outages are currently used to notify System Management when a dual-fuel Scheduled Generator is unable to operate on one of its nominated fuels. There is no explicit obligation in the Market Rules or the Power System Operation Procedure: Facility Outages to request/report outages that limit the ability of a Scheduled Generator to operate using one of its fuels. In terms of the provision of sent out energy (the service used to determine Capacity Cost Refunds), it is questionable whether this situation qualifies as an outage at all. More generally, the Market Rules lack clarity on the nature and extent of a Market Generator’s obligations to ensure that its Facility can operate on the fuel used for its certification, what (if anything) should occur if these obligations are not met, and the implications for outage scheduling and Reserve Capacity Testing. (See section 7.2.2.5 of the Final Rule Change Report for RC_2013_15.)	The MAC agreed that this issue should be placed on hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020).
59	MAC October 2019	**Ancillary Service outage scheduling anomalies** Currently Registered Facilities that provide Ancillary Services under an Ancillary Service Contract must be included on the Equipment List. This creates the following potential anomalies: • some Ancillary Service Contracts may include outage reporting provisions that are specific to the service and may differ from the standard outage scheduling provisions for Equipment List Facilities;	The MAC agreed that this issue should be placed on hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020).

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		• Market Participants are not required to schedule outages in relation to the availability of their LFAS Facilities to provide LFAS; • Synergy is not required to schedule outages in relation to the availability of its Facilities to provide uncontracted Ancillary Services; and • a contracted Ancillary Service may not always be provided by a Registered Facility. A review of the outage scheduling requirements relating to Ancillary Services may be warranted to resolve any anomalies and ensure that the obligations on Rule Participants to schedule outages for Ancillary Services are appropriate and consistent. (See section 7.2.2.5 of the Final Rule Change Report for RC_2013_15.)	
60	MAC October 2019	**Outage scheduling obligations for Interruptible Loads** The Market Rules require all Registered Facilities that are subject to an Ancillary Service Contract to be included on the Equipment List. This includes the Interruptible Loads that are used to provide Spinning Reserve Service. However, the Market Rules do not explicitly state who is responsible for outage scheduling for Interruptible Loads. This is a problem because the counterparty to an Interruptible Load Ancillary Service Contract may be an Ancillary Service Provider, and not the Market Customer (usually a retailer) to whom the Interruptible Load is registered. An Ancillary Service Provider is	The MAC agreed that this issue should be placed on hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020).

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		not subject to obligations placed on a 'Market Participant or Network Operator', while the retailer for an Interruptible Load may not have any involvement with the Interruptible Load arrangement or the management of outages for that Load. (See section 7.2.3.1 of the Final Rule Change Report for RC_2013_15.)	
61	MAC October 2019	**Direction of Self-Scheduling Outage Facilities** An apparent conflict exists in the Market Rules between clauses that appear to allow System Management to reject or recall Planned Outages of Self-Scheduling Outage Facilities (e.g. clauses 3.4.3(a), 3.4.3(b), 3.4.4 and 3.5.5(c)) and clauses that appear to exempt Planned Outages of Self-Scheduling Outage Facilities from rejection or recall, such as: • clause 3.18.2A, which explicitly exempts Self-Scheduling Outage Facilities from obligations under section 3.20; • clause 3.19.5, which allows System Management to reject an approved Scheduled Outage or Opportunistic Maintenance but fails to mention Planned Outages of Self-Scheduling Outage Facilities (which are neither Scheduled Outages nor Opportunistic Maintenance); and • clause 3.19.6(d), which sets out a priority order for System Management to consider when it determines which previously approved Planned Outage to reject but does not include any reference to Planned Outages of Self-Scheduling Outage Facilities.	The MAC agreed that this issue should be placed on hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020).

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		(See section 7.2.3.2 of the Final Rule Change Report for RC_2013_15.)	
62	MAC October 2019	**Outage scheduling obligations for non-intermittent Non-Scheduled Generators** Under the Market Rules: • a non-intermittent generation system with a rated capacity between 0.2 MW and 10 MW may be registered as a Non-Scheduled Generator; and • a non-intermittent generation system with a rated capacity less than 0.2 MW can only be registered as a Non-Scheduled Generator. To date, no non-intermittent generation systems have been registered as Non-Scheduled Generators. However, if a non-intermittent Non-Scheduled Generator was registered it would be able to apply for Capacity Credits, and if assigned Capacity Credits would also be assigned a non-zero Reserve Capacity Obligation Quantity (**RCOQ**). While this would make the Non-Scheduled Generator subject to the same RCOQ-related Scheduling Day obligations as a Scheduled Generator, the Non-Scheduled Generator's Balancing Market obligations are more uncertain and were not considered in the development of RC_2013_15. The Balancing Submissions for a Non-Scheduled Generator comprise a single Balancing Price-Quantity Pair with a MW quantity equal to the Market Generator's "best estimate of the Facility's output at the end of the Trading Interval". There is no clear obligation to make the Facility's RCOQ	The MAC agreed that this issue should be placed on hold until the regulatory changes for the Foundation Regulatory Frameworks workstream are known (mid-2020).

Table 4 – Issues on Hold			
Id	**Submitter/Date**	**Issue**	**Urgency and Status**
		available for dispatch or to report an outage for capacity not made available, because new section 7A.2A, which will clarify these obligations for Scheduled Generators, does not apply to Non-Scheduled Generators. The need to cater for non-intermittent, Non-Scheduled Generators also affects the determination of capacity-adjusted outage quantities and outage rates and is likely to increase IT costs and the complexity of the Market Rules. (See section 7.2.3.4 of the Final Rule Change Report for RC_2013_15.)	

Notes:

- These are issues that the MAC will consider following some identified event. Issues on Hold will be reviewed by the MAC once the identified event has occurred, and then closed or moved to another sub-list.

MARKET ADVISORY COMMITTEE MEETING, 26 NOVEMBER 2019

FOR NOTING

SUBJECT: UPDATE ON AEMO'S MARKET PROCEDURES

AGENDA ITEM: 7

1. PURPOSE

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

2. AEMO PROCEDURE CHANGE WORKING GROUP (APCWG)

	Most recent meeting	**Next meeting**
Date	21 Oct 2019	12 Dec 2019 (TBC)
Market Procedures for discussion	• Market Procedure: Prudential Requirements	• PSOP: Outages (due to RC_2013_15)

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as at 19 November 2019. Changes since the previous MAC meeting are in red text. A procedure change is removed from this report after its commencement has been reported or a decision has been taken not to proceed with a potential Procedure Change Proposal.

ID	**Summary of changes**	**Status**	**Next steps**	**Date**
AEPC_2019_11: Market Procedure: Prudential Requirements	The proposed amendments predominantly arise from Rule Change RC_2015_03 (Formalisation of the Process for Maintenance Applications)	Considered by APCWG 21 Oct 2019. Procedure Change Proposal published 4 Nov 2019.	Submissions close	2 Dec 2019

RCP | Rule Change Panel
Market Advisory Committee

Agenda Item 8(a): Overview of Rule Change Proposals (as at 19 November 2019)

Meeting 2019_11_26

- Changes to the report provided at the previous Market Advisory Committee meeting are shown in red font.
- The next steps and the timing for the next steps are provided for Rule Change Proposals that are currently being actively progressed by the Rule Change Panel (**Panel**) or the Minister.

Indicative Rule Change Panel Activity Until the Next MAC Meeting

Reference	Title	Events	Indicative Timing
RC_2014_03	Administrative Improvements to Outage Process	Publication of call for further submissions	02/12/2019
		Further submission period closes	10/01/2020
		Publication of Extension Notice for the Draft Rule Change Report	09/12/2019
RC_2014_05	Reduced Frequency of the Review of Energy Price Limits and the Maximum Reserve Capacity Price	Publication of Extension Notice for the Draft Rule Change Report	09/12/2019
RC_2014_09	Managing Market Information	Publication of Final Rule Change Report	13/12/2019
RC_2017_02	Implementation of 30-Minute Balancing Gate Closure	Publication of Extension Notice for the Draft Rule Change Report	09/12/2019
		Publication of Draft Rule Change Report	07/02/2020
		Submissions due on the Draft Rule Change Report	09/03/2020

Reference	Title	Events	Indicative Timing
RC_2018_03	Capacity Credit Allocation Methodology for Intermittent Generators	Publication of Extension Notice for the Draft Rule Change Report	09/12/2019
RC_2018_05	ERA Access to market information and SRMC investigation process	Commencement (pending approval of the Amending Rules by the Minister for Energy by 16/12/2019)	02/01/2020
RC_2019_04	Administrative Improvements to Settlement	Publication of Rule Change Notice	27/11/2019
		First submission period closes (pending a Panel decision to progress the Rule Change Proposal)	31/01/2020
RC_2019_05	Amending the Minimum STEM Price definition and determination	Submissions due on the Rule Change Proposal	18/12/2019
NA	Market Advisory Committee (**MAC**) Composition Review 2020	Publication of call for nominations	02/12/2019
		Close of nominations	17/01/2020
		Panel appointment of new MAC members	28/02/2020
N/A	Framework for Rule Change Proposal Prioritisation and Scheduling	Publication of a revised version of the framework	02/01/2020

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

Reference	Submitted	Proponent	Title	Commenced
None				

Approved Rule Change Proposals Awaiting Commencement

Reference	Submitted	Proponent	Title	Commencement
RC_2013_15	24/12/2013	IMO	Outage Planning Phase 2 – Outage Process Refinements	01/02/2020

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

Reference	Submitted	Proponent	Title	Rejected
None				

Rule Change Proposals Awaiting Approval by the Minister

Reference	Submitted	Proponent	Title	Approval Due Date
RC_2018_05	27/09/2018	ERA	ERA access to market information and SRMC investigation process	16/12/2019

Formally Submitted Rule Change Proposals

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
Fast Track Rule Change Proposals with Consultation Period Closed						
None						
Fast Track Rule Change Proposals with Consultation Period Open						
None						
Standard Rule Change Proposals with Second Submission Period Closed						
RC_2014_09	13/03/2015	IMO	Managing Market Information	Low	Publication of Final Rule Change Report	13/12/2019

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
Standard Rule Change Proposals with Second Submission Period Open						
None						
Standard Rule Change Proposals with First Submission Period Closed						
RC_2014_03	27/11/2014	IMO	Administrative Improvements to the Outage Process	High	Publication of a CFFS	09/12/2019
RC_2014_05	02/12/2014	IMO	Reduced Frequency of the Review of the Energy Price Limits and the Maximum Reserve Capacity Price	Medium	Publication of Draft Rule Change Report	31/12/2019
RC_2017_02	04/04/2017	Perth Energy	Implementation of 30-Minute Balancing Gate Closure	Medium	Publication of Draft Rule Change Report	07/02/2020
RC_2018_03	01/03/2018	Collgar Wind Farm	Capacity Credit Allocation Methodology for Intermittent Generators	Medium	Publication of Draft Rule Change Report	31/12/2019
RC_2019_01	21/06/2019	Enel X	The Relevant Demand calculation	Medium	Publication of Draft Rule Change Report	30/06/2020
Standard Rule Change Proposals with the First Submission Period Open						
RC_2019_04	AEMO	AEMO	Administrative Improvements to Settlement	Medium	Close of the first submission period (pending Panel approval to progress the Rule Change Proposal)	31/02/2020
RC_2019_05	25/10/2019	Synergy	Amending the Minimum STEM Price definition and determination	TBD	Close of the first submission period	18/12/2019

Pre-Rule Change Proposals

Reference	Proponent	Description	Next Step	Submitted
RC_2019_03	ERA	Method used for the assignment of Certified Reserve Capacity to Intermittent Generators	Submit Rule Change Proposal	TBD
TBD	Perth Energy	Issues with Reserve Capacity Testing	Submit Pre-Rule Change Proposal	TBD
TBD	AEMO	North Country Spinning Reserve	Submit Pre-Rule Change Proposal	TBD

Rule Changes Made by the Minister

Gazette	Date	Title	Commencement
2019/151	22/10/2019	Wholesale Electricity Market Amendment (AEMO to provide information to the Minster) Rule 2019	01/11/2019

RCP | Rule Change Panel
Market Advisory Committee

Agenda Item 8(c): Market Participant Fee calculation manifest error

Meeting 2019_11_26

1. Background

On 27 June 2018, the Rule Change Panel and the Minister for Energy approved Rule Change Proposal RC_2017_06: Reduction of the prudential exposure in the Reserve Capacity Mechanism. AEMO established the Reduction of Prudential Exposure (**RoPE**) project to implement RC_2017_06 and to change the Outstanding Amount equation as outlined in AEMO's Market Procedure: Prudential Requirements change AEPC_2019_03.

On 14 November 2019, AEMO notified RCP Support of an alleged manifest error in the calculation of Market Participant Fees that it identified during the work on the RoPE project. The alleged manifest error is in clause 9.13.1 of the Market Rules is as follows (the relevant parts of the clause with the manifest error are highlighted in yellow):

9.13.1. The applicable Market Participant Fee settlement amount for Market Participant p for Trading Month m is:

MPFSA(p,m) = (-1) x (Market Fee rate + System Management Fee rate
+ Regulator Fee rate) x
(Monthly Participant Load(p,m) + Monthly Participant Generation(p,m))

Where

Market Fee rate is the charge per MWh for AEMO's services determined in accordance with clause 2.24.2 for the year in which Trading Month m falls;

System Management Fee rate is the charge per MWh for AEMO's system management services determined in accordance with clause 2.24.2 for the year in which Trading Month m falls;

Regulator Fee rate is the charge per MWh for funding the Economic Regulation Authority's and the Rule Change Panel's activities with respect to the Wholesale Electricity Market and other functions under these Market Rules and the Regulations determined in accordance with clause 2.24.2 for the year in which Trading Month m falls;

Monthly Participant Load(p,m) = (-1) × Sum(d∈D,t∈T,Metered Load(p,d,t));

where

Metered Load(p,d,t) for a Market Participant p for a Trading Interval t is the sum of the mathematical absolute values of the Metered Schedules for the Non-Dispatchable Loads and Interruptible Loads, registered to the Market Participant for Trading Interval t; and

Monthly Participant Generation(p,m)
= Sum(d∈D,t∈T, Metered Generation(p,d,t));

where

Metered Generation(p,d,t) for Market Participant p for Trading Interval t is the sum of the mathematical absolute values of the Metered Schedules for Scheduled Generators and Non-Scheduled Generators, registered to the Market Participant for Trading Interval t; and

D is the set of all Trading Days in Trading Month m, where “d” is used to refer to a member of that set;

T is the set of all Trading Intervals in Trading Day d, where “t” is used to refer to a member of that set.

Under the current Market Rules, the Monthly Participant Load(p,m) results in a negative number as the Metered Load(p,d,t) is an absolute value. Consequently in the final calculation of the Market Participant Fee Calculation amount, MPFSA(p,m), will result in a positive amount due to the (-1) in the formula.

Consequently, under the current Market Rules, a Market Customer would be paid a Market Participant Fee, a Market Generator would be charged and a Market Participant that equally consumes and generates would pay no fees. Examples of these scenarios are provided in the appendix to this paper to illustrate the alleged manifest error.

AEMO’s understanding is that clause 9.13.1 is intended to charge Market Participant Fees on both generation and consumption, and AEMO has confirmed that it currently calculates Market Participant Fees in accordance with its understanding.

However, AEMO has indicated that it does not currently have adequate resources to develop and submit a Rule Change Proposal to address the issue that it has identified, so it has asked the Rule Change Panel to develop a proposal and progress it under the Fast Track Rule Change Process.

2. Issues for Feedback from the MAC

(a) Is the Issue a Manifest Error

The Rule Change Panel may develop a Rule Change Proposal[1] only when a change to the Market Rules is:

- required to correct a manifest error; or
- of minor or procedural nature.

The term ‘manifest error’ is not defined, but the dictionary definition of manifest is ‘clear or obvious to the eye or mind’. The MAC’s views are sought on whether the issue identified by AEMO is a manifest error.

(b) Should the Rule Change Panel Develop and Submit a Rule Change Proposal using the Fast Track Rule Change Process

The Standard Rule Change Process includes two rounds of public consultation and should take around 19 weeks to complete (unless the process is extended).

[1] Clause 2.5.4 of the Market Rules.

The Fast Track Rule Change Process includes one round of stakeholder consultation and should take around five weeks to complete (unless the process is extended). The Fast Track Rule Change Process can only be used when the Rule Change Proposal:

- is of a minor or procedural nature; or
- is required to correct a manifest error; or
- is urgently required and is essential for the safe, effective and reliable operation of the market or the SWIS.

If the MAC agrees that the issue is a manifest error, then the MAC's views are sought on:

- whether the Rule Change Panel should develop and submit a Rule Change Proposal to address the manifest error; and
- if so, which rule change process should be used?

Note that clause 9.13.1 is a Protected Provision and in accordance with clause 2.8.3, the Rule Change Panel must submit a Rule Change Proposal and the Final Rule Change Report to the Minister for approval when there is proposal to amend or replace a Protected Provision.

(c) Timing for Developing and Submitting a Rule Change Proposal

If the MAC is of the view that a Rule Change Proposal to address this issue should use the Fast Track Rule Change Process, then the MAC's views are sought on when RCP Support should develop and submit the proposal, noting that a fast-tracked Rule Change Proposal will effectively be given a top priority once it is submitted.

If the MAC is of the view that a Rule Change Proposal to address this issue should use the Standard Rule Change Process, then the MAC's views are sought on the urgency rating for the proposal. The urgency ratings from the Rule Change Proposal Prioritisation and Scheduling Framework are as follows:

Urgency	Description	Resourcing Implications
1	**Essential:** e.g. legal necessity, unacceptable market outcomes or a serious threat to power system security and reliability.	Do not delay – acquire additional resources, request increase to the ERA budget from Treasury if necessary
2	**High:** Compelling proposal, and either large net benefit or else necessary to avoid serious perverse market outcomes.	Do not delay – acquire additional resources if available subject to overall ERA budget limitations
3	**Medium:** Net benefit either: • may be large but needs more analysis to determine; or • material but not large enough to warrant a High rating.	May delay up to 3 months if budgeted resources unavailable
4	**Low:** Minor net benefit (e.g. reduced administration costs).	May delay up to 6 months if budgeted resources unavailable

Urgency	Description	Resourcing Implications
5	**Housekeeping:** Negligible market benefit, e.g. just improves the readability of the Market/GSI Rules	May delay up to 12 months if budgeted resources unavailable

Appendix – Examples under the current Market Rules

Clause 9.13.1 is as follows:

$$\begin{aligned}\mathrm{MPFSA(p,m)} \;&=\; (-1) \times (\text{Market Fee rate} + \text{System Management Fee rate} + \text{Regulator Fee rate}) \\ &\quad \times \big(\text{Monthly Participant Load(p, m)} + \text{Monthly Participant Generation(p, m)}\big)\end{aligned}$$

$$\text{Monthly Participant Load(p, m)} = (-1) \times \sum_{\mathrm{d \in D, t \in T}} \text{Metered Load(p, d, t)}$$

$$\text{Metered Load(p, d, t)} = \sum_{\substack{\text{f}\in\text{Non-Dispatchable Loads} \\ \text{and Interruptible Loads}}} |\text{Metered Schedule(f, t)}|$$

$$\text{Monthly Participant Generation(p, m)} = \sum_{\mathrm{d \in D, t \in T}} \text{Metered Generation(p, d, t)}$$

$$\text{Metered Generation(p, d, t)} = \sum_{\substack{\text{f}\in\text{Scheduled and Non-Scheduled} \\ \text{Generators}}} |\text{Metered Schedule(f, t)}|$$

Example 1: To illustrate generation and load offsetting each other

Let (Market Fee rate + System Management Fee rate + Regulator Fee rate) =$1/MWh and consider a Market Participant with:

- a single Non-Dispatchable Load that consumes 1MWh (loss-adjusted) in every Trading Interval in April; and
- a single Scheduled Generator that generates 1MWh (loss-adjusted) in every Trading Interval in April.

$$\mathrm{MPFSA(p,m)} \;=\; (-1) \times (\$1/\mathrm{MWh}) \times (-1{,}440\mathrm{MWh} + 1{,}440\mathrm{MWh}) = \$0$$

$$\text{Monthly Participant Load(p, m)} = (-1) \times 30 \times 48 \times 1\mathrm{MWh} = -1{,}440\mathrm{MWh}$$

$$\text{Metered Load(p, d, t)} = |-1\mathrm{MWh}| = 1\mathrm{MWh}$$

$$\text{Monthly Participant Generation(p, m)} = 30 \times 48 \times 1\mathrm{MWh} = 1{,}440\mathrm{MWh}$$

$$\text{Metered Generation(p, d, t)} = |1\mathrm{MWh}| = 1\mathrm{MWh}$$

The current Market Participant would <u>pay no fees</u> under the current Market Rules.

Example 2: To illustrate load being paid

Let (Market Fee rate + System Management Fee rate + Regulator Fee rate) =$1/MWh and consider a Market Participant with:

- a single Non-Dispatchable Load that consumes 1MWh (loss-adjusted) in every Trading Interval in April.

$$\mathrm{MPFSA(p,m)} \;=\; (-1) \times (\$1/\mathrm{MWh}) \times (-1{,}440\mathrm{MWh} + 0\mathrm{MWh}) = \$1{,}440$$

$$\text{Monthly Participant Load(p, m)} = (-1) \times 30 \times 48 \times 1\mathrm{MWh} = -1{,}440\mathrm{MWh}$$

$$\text{Metered Load}(p, d, t) = |-1\text{MWh}| = 1\text{MWh}$$

$$\text{Monthly Participant Generation}(p, m) = 30 \times 48 \times 0\text{MWh} = 0\text{MWh}$$

$$\text{Metered Generation}(p, d, t) = |0\text{MWh}| = 0\text{MWh}$$

The Market Participant would be paid under the current Market Rules.

Example 3: To illustrate generation being charged

Let (Market Fee rate + System Management Fee rate + Regulator Fee rate) =$1/MWh and consider a Market Participant with:

- a single Scheduled Generator that generates 1MWh (loss-adjusted) in every Trading Interval in April.

$$\text{MPFSA}(p, m) = (-1) \times (\$1/\text{MWh}) \times (0\text{MWh} + 1{,}440\text{MWh}) = -\$1{,}440$$

$$\text{Monthly Participant Load}(p, m) = (-1) \times 30 \times 48 \times 0\text{MWh} = 0\text{MWh}$$

$$\text{Metered Load}(p, d, t) = |0\text{MWh}| = 0\text{MWh}$$

$$\text{Monthly Participant Generation}(p, m) = 30 \times 48 \times 1\text{MWh} = 1{,}440\text{MWh}$$

$$\text{Metered Generation}(p, d, t) = |1\text{MWh}| = 1\text{MWh}$$

The Market Participant would be charged under the current Market Rules.

Agenda Item 8(d)

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Pre-rule change proposal

Changes to the Data & IT Interface Procedure

Background

Requirement: Clause 2.36.5 states:

> *AEMO must document the data and IT interface requirements, including security standards required for Market Participants to operate in the Wholesale Electricity Market in the relevant procedure to which the system pertains*

Current practice: AEMO currently documents the information required under clause 2.36.5 in a single Market Procedure: Data and IT Interface Requirements

Updated Interpretation: AEMO to document this information in the market procedure that relates a system. e.g. the IT information relating to how a Market Participant accesses settlement data / settlements system must be documented in the Settlement Procedure.

Issues

During the implementation of RC_2014_06 – Removal of Resource Plans and Dispatchable Loads, the following issues were identified:

- To comply with 2.36.5 as currently drafted, the same information would likely be *repeated* across several Market Procedures
- If there was a IT system change that impacts how Market Participants participant in the WEM, this information would need to be updated in several Market Procedures.
- Market Procedure may not be an appropriate document to detail prescriptive data & IT interface requirements (which can be relatively dynamic for individual systems).
- The clause is silent on whether there is a requirement to document information in relation to systems which Market Participants do not directly interact with (e.g. RTDE)

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Considerations

- Is Market Procedure useful to Market Participants?

- If so, what information should be included?

Options

To address these issues, AEMO has identified three options for this rule change

1. **Maintain Market Procedure with updated content:** Modify clause 2.36.5 to reference information that is valuable to market participants and allows AEMO to document the necessary information in a **single market procedure**.

2. **Publish updated content in a document on market website:** Modify clause 2.36.5 to reference information that is valuable to market participants and enable AEMO to publish this information (on the market website) in a document that is **not a market procedure**.

3. **Remove obligation to provide this information:** Delete clause 2.36.5 on the proviso that the current content of the procedure provides minimal benefit to market participants and no alternative content has been identified by AEMO or market participants.

Next Steps

AEMO seeks MAC's views on whether AEMO should progress this as a rule change proposal.

If MAC agrees that this should be progressed:

1) AEMO will proceed with the preferred option
2) MAC to provide an appropriate timeframe to provide technical feedback to AEMO to be considered for the Pre-Rule Change Proposal.

Contact Details

Please provide technical feedback to:

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