RCP Rule Change Panel
Market Advisory Committee

Meeting Agenda

Meeting Title:	Market Advisory Committee
Date:	Wednesday 14 February 2018
Time:	12:30 pm – 4:00 pm
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	Minutes from Previous Meeting	Chair	5 min
4	Actions Items	Chair	15 min
	(a) ERA Market Reviews Update (Action Item 29/2017)	ERA	10 min
5	ERA Presentations	ERA	
	(a) Effectiveness of the Synergy Regulatory Regime 2016	ERA	20 min
	(b) 2016/17 WEM Report	ERA	20 min
6	Market Rules		
	(a) Overview of Rule Change Proposals	RCP Support	15 min
	(b) RC_2018_01 (New Notional Wholesale Meter Manifest Error) – Pre-Rule Change Proposal	RCP Support	15 min
	(c) RC_2018_02 (K and U parameters in Relevant Level Methodology for 2018 Reserve Capacity Cycle) – Pre-Rule Change Proposal	AEMO	15 min
	(d) RC_2014_03 (Administrative Improvements to Outage Processes) – Presentation	RCP Support	30 min
7	Update on AEMO's Market Procedures	AEMO	10 min
8	Network and Market Reform Program Update	PUO	30 min
9	Update on the MAC Market Rules Issues List	RCP Support	10 min
10	General Business (no paper)	Chair	5 min
Next Meeting: 14 March 2018			

Please note, this meeting will be recorded.

RCP | Rule Change Panel
Market Advisory Committee

Minutes

Meeting Title:	Market Advisory Committee (MAC)
Meeting No:	2017-08
Date:	13 December 2017
Time:	1:05 PM – 4:00 PM
Location:	Training Room No. 1, Albert Facey House 469 Wellington Street, Perth

Attendees	Class	Comment
Stephen Eliot	Chair	
Aditi Varma	Minister's Appointee – Small-Use Consumer Representative	Proxy, to 2:30 PM
Dean Sharafi	System Management	
Sara O'Connor	Economic Regulation Authority (ERA) Observer	To 1:40 PM
Will Bargmann	Synergy	
Wendy Ng	Market Generators	
Andrew Stevens	Market Generators	
Jacinda Papps	Market Generators	
Patrick Peake	Market Customers	
Alex Penter	Market Customers	Proxy
Geoff Gaston	Market Customers	
Peter Huxtable	Contestable Customers	

Apologies	Class	Comment
Matthew Martin	Minister's Appointee – Small-Use Consumer Representative	
Martin Maticka	AEMO	
Margaret Pyrchla	Network Operator	
Shane Cremin	Market Generators	
Steve Gould	Market Customers	
Simon Middleton	Market Customers	

Also in attendance	From	Comment
Jenny Laidlaw	RCP Support	Presenter
Laura Koziol	RCP Support	Presenter
Richard Cheng	RCP Support	Presenter
Ashwin Raj	Public Utilities Office (PUO)	Presenter, to 1.50 PM
Bobby Ditric	PUO	Presenter
Manuel Arapis	ERA	Presenter, to 1:30 PM
Adrian Theseira	ERA	Presenter
Daniel Kurz	Bluewaters Power	Presenter
Ignatius Chin	Bluewaters Power	Presenter
Stuart Featham	AEMO	Observer
Angelina Cox	Synergy	Observer
Tim McLeod	Amanda Energy	Observer
Noel Schubert		Observer
Sandra Ng Wing Lit	RCP Support	Minutes

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 1:05 PM and welcomed members and observers to MAC meeting 2017-08.	
2	**Meeting Apologies/Attendance** The Chair noted the apologies, attendance, and proxies, as listed above.	
3	**Minutes from Previous Meeting** The minutes of MAC meeting 2017-07 held on 8 November 2017 were circulated on 29 November 2017. The minutes were accepted as a true record of the meeting. ***Action: RCP Support to publish the minutes of meeting 2017-07 on the Rule Change Panel's website as final.***	**RCP Support**
4	**Actions Arising** The closed action items were taken as read. **Action 19/2017**: Mr Bobby Ditric requested the action item be carried over to the next MAC meeting. Mr Ditric advised that the PUO had discussed the issues with RCP Support and AEMO, and	

	expected to present two Pre Rule Change Proposals at the next MAC meeting: • a fast track (manifest error) proposal to clarify wording around the confidentiality status of generator modelling information; and • a proposal to prevent a generator from being placed on a Forced Outage due to problems with modelling data that was provided by another party. **Action 28/2017**: Mr Dean Sharafi advised that dynamic refund factors were published in the participant information reports that accompanied the October 2017 Settlement Statements. Mr Sharafi also noted that AEMO was working on changes to the Outstanding Amount calculation in parallel with progression of Rule Change Proposal RC_2017_06 (Reduction of the prudential exposure in the Reserve Capacity Mechanism). AEMO proposed to provide estimates of dynamic refund rates as a part of this work. Mr Patrick Peake noted that Market Generators needed information on refund rates very quickly as they often had obligations to report to their financiers regarding the expected costs of any Forced Outage. Mr Sharafi suggested the action item remain open until AEMO provided a further update in the New Year. **Action 29/2017**: Carried over to the next MAC meeting at the request of Ms Sara O'Connor. **Action 31/2017**: Mr Sharafi noted that changes to SMMITS and the settlement adjustment rules would be required to support the reporting of Forced Outages after the current 15 day deadline. Mr Sharafi proposed to keep the action item open until AEMO was able to provide further information on the required changes. **Action 32/2017**: Ms Jenny Laidlaw advised that the Energy Market Operations and Processes (EMOP) Consultation Group had discussed an enhancement to allow a responsible procedure administrator to make trivial changes to Market Procedures without having to go through the full Procedure Change Process. Under the proposal, the responsible procedure administrator would publish details of its proposed changes and give stakeholders two weeks to raise any concerns. If no concerns were raised during this period then the responsible procedure administrator could make the changes without any further consultation; but if requested by any stakeholder, the responsible procedure administrator would be required to follow the normal Procedure Change Process. Ms Laidlaw noted that RCP Support did not consider there was any need for a process of this type to manage minor changes to the Market Rules. **Action 33/2017**: Ms Aditi Varma requested the action item be carried over to the New Year, noting that a review of Protected Provisions was not a priority for the PUO at this time. **Action 34/2017**: Mr Sharafi noted that some work had been done but requested the action item be carried over to the next MAC meeting.	

	Action 36/2017: The Chair advised that preliminary discussions on the review topics identified by the MAC are scheduled to commence in early 2018.	
5	**Presentation – Balancing Offer Market Guideline** Mr Manuel Arapis gave a presentation on the draft Balancing Submission Guideline (Guideline) being developed by the ERA. The Guideline is intended to provide clarity to Market Generators on how the ERA interprets the undefined terms ("reasonable expectation", "short run marginal cost" (SRMC), "relates to" and "market power") in clause 7A.2.17 of the Market Rules. The presentation is available on the Rule Change Panel's website. The following points were discussed. • Mr Andrew Stevens asked whether the ERA's definition of SRMC accounted for the market risk of a Scheduled Generator incurring Capacity Cost Refunds by tripping off while generating. Mr Arapis replied that the ERA did not consider capacity refund costs to be a component of SRMC. • Mrs Jacinda Papps asked whether the ERA intended for the new Guideline to replace the other SRMC guidance documents already published on the ERA website. Mr Arapis replied that the new Guideline was intended as a complement paper rather than as a replacement for the previous documents. • Mr Peake noted that one of the main issues facing Market Generators is the impact of start-up costs when there is uncertainty about run times. Mr Peake considered that while it may not be possible to modify the current dispatch engine, serious consideration should be given to having start-up costs (and potentially shut-down costs) as separate components of dispatch offers, to prevent the problems faced by Market Generators in incorporating these costs into their offer prices. Ms Laidlaw noted that stakeholders had expressed universal opposition to the implementation of an American-style multi-part bidding regime during the EMOP investigations. Ms Laidlaw suggested that stakeholders should talk to the PUO if they now held a different view and thought the market should move towards multi-part bidding. There was some discussion about the advantages (e.g. removing the need for Market Generators to estimate their run-times) and impacts (e.g. increased complexity of implementation and shifting of the risk of not recovering start-up costs from the generator to the market) of multi-part bidding.	
6a	**Overview of Rule Change Proposals** Ms Laura Koziol noted that: • the Draft Rule Change Report for RC_2017_06 was published on 13 November 2017, with the second submission period to close on 16 January 2018; and • the second submission period for Rule Change Proposal RC_2017_05 (AEMO Role in Market Development) closed on	

	22 November 2017; two submission were received and the Final Rule Change Report is due to be published on 20 December 2017. The Chair noted that the Rule Change Panel would be publishing new extension notices for the remaining legacy Rule Change Proposals in the near future. RCP Support had started development of a work program aimed at clearing as much of the rule change backlog as possible before the next wave of Rule Change Proposals from the PUO's reform program.	
6b	**Presentation – Administrative Improvements to the Outage Process (RC_2014_03)** *(Note that the title of this agenda item was incorrect in the meeting agenda, as it referred to RC_2013_15 (Outage Planning Phase 2 – Outage Process Refinements) instead of RC_2014_03).* Ms Laidlaw provided an update on the Rule Change Proposal RC_2014_03 (Administrative Improvements to the Outage Process). The presentation is available on the Rule Change Panel's website. The following points were discussed. • Ms Laidlaw noted that RCP Support is seeking legal advice on whether the Rule Change Panel could address two candidate issues for the MAC Market Rules Issues List in RC_2014_03. These issues would be added to the Market Rules Issues List if they cannot be addressed as part of RC_2014_03. • Ms Wendy Ng raised a concern about the straw man proposal for determining outage quantities for Scheduled Generators that trip off during a Trading Interval (slide 7 of the presentation). Ms Ng considered that the proposed calculation method could overstate the outage quantity, as it did not recognise that the full capacity of the unit was available during the period preceding the trip. Ms Laidlaw acknowledged Ms Ng's concerns and invited stakeholders to suggest an alternative approach that was simple, measurable and auditable, noting that RCP Support had not to date found a better option than the one presented (taking into account all the costs and benefits). Mr Stevens noted that any overstatement of outage quantity would only apply to the Trading Interval in which the trip occurred, and that the cost and complexity of alternative approaches may not be justified. • There was some discussion about whether capacity-adjusted outage quantities should be calculated in SMMITS or AEMO's settlement systems. • In response to a query from Mr Sharafi, Ms Laidlaw confirmed that a Market Generator is not permitted to perform maintenance on a unit while it is subject to a Consequential Outage. • Mrs Papps gave a recent example of where a Pinjarra unit under automatic generation control (AGC) was dispatched down	

	via its AGC instructions in conflict with its formal Dispatch Instruction. There was some discussion about whether such occurrences should be treated as Consequential Outages, even though they did not specifically relate to the outage of another piece of equipment. • Ms Laidlaw noted that RCP Support intended to hold a workshop in January 2018 on RC_2014_03, with AEMO, Western Power and any other interested parties. In response to a question from Mr Ignatius Chin, Ms Laidlaw confirmed that anyone with an interest in RC_2014_03 was welcome to attend the workshop. ***Action: MAC members and observers to email RCP Support by 5:00 PM on Wednesday, 20 December 2017 to:*** • ***provide any feedback on the points raised in the 13 December 2017 presentation on RC_2014_03 (Administrative Improvements to the Outage Process); and*** • ***indicate whether they are interested in attending the proposed January 2018 workshop, and if so when they are available during that month.***	**All**
6c	**Discussion – Removal of Resource Plans and Dispatchable Loads (RC_2014_06)** Ms Koziol gave a presentation on Rule Change Proposal RC_2014_06 (Removal of Resource Plans and Dispatchable Loads). The presentation is available on the Rule Change Panel's website. The following points were discussed. • In response to a question from Mr Chin, Ms Koziol clarified that the reason for considering a reduction in the length of the STEM Submission window is that AEMO's bidding system for NEMDE assumed a 12:30 PM extension of the dispatch horizon. If NEMDE is implemented in the WEM in future, then using the same time would reduce implementation costs and maximise the potential re-use of third party supporting software. Ms Koziol noted there were two questions for stakeholders: o whether to future proof the WEM design by moving the Balancing Horizon extension time to 12:30 PM; and o if the answer to the first question is yes, whether this should be accomplished by reducing the length of the STEM Submission window or reducing the period between the publication of the STEM Auction results and 12:30 PM. There was some discussion about the pros and cons of each option. • Ms Ng asked whether Synergy would still require Dispatch Plans if the proposed energy market reforms are implemented. Mr Sharafi replied that if Synergy moved to facility bidding, then it would operate like any other Market Generator and so would not require Dispatch Plans. • Mr Peter Huxtable asked whether RCP Support was sure that the Minister's removal of AEMO's ability to delay Scheduling	

	Day events due to problems with the daily Ancillary Service files was accidental rather than deliberate. Ms Koziol confirmed RCP Support was confident that the removal was accidental. • Mr Huxtable asked whether there were any ring-fencing or similar arrangements within AEMO that would warrant the retention of System Management as a distinct entity in the Market Rules. Mr Sharafi replied that there were no such arrangements and AEMO's starting position was that the term "System Management" should be removed from the Market Rules. However, Mr Sharafi noted that AEMO was uncertain about the implications of such a change and so this is not AEMO's final position. Mrs Papps questioned whether the removal of the term should be included in the scope of RC_2014_06. Ms Laidlaw noted that the intent was not to include the removal of all instances of the term in the scope of RC_2014_06, but only those in the clauses directly affected by the Rule Change Proposal. Mrs Papps agreed that it would be sensible to review the use of the term in those clauses. Mr Stevens, while not proposing that the term be retained, suggested two possible reasons for its retention: o it might help reduce confusion in the Market Rules by clarifying when AEMO was performing functions associated with its system operations role; and o to future proof in case System Management's functions were ring-fenced again in future. Mrs Papps noted that currently AEMO and System Management had separate representatives at the MAC. Ms Koziol considered it would be possible to retain separate market operations and system operations representatives from AEMO without retaining the term "System Management". There was general agreement that the practical implications of removing the term need to be considered before making any changes to the Market Rules. Ms Koziol asked MAC members and observers to respond via email to the questions raised in the presentation. Ms Koziol noted that RCP Support intended to publish a call for further submissions by the end of January 2018 and on the Draft Rule Change Report by March/April 2018.	
	Action: MAC members and observers to email RCP Support any feedback on the questions raised in the 13 December 2017 presentation on RC_2014_06 (Removal of Resource Plans and Dispatchable Loads) by 5:00 PM on Wednesday, 20 December 2017.	**All**
6d	**Discussion – Correction of Gazettal Errors (RC_2017_10)** The Chair noted that the Rule Change Panel developed the Pre Rule Change Proposal RC_2017_10 (Correction of Gazettal Errors) to address a number of manifest errors in the Market Rules caused by errors in the amending rules Gazetted by the Minister over the	

	period between 2015 and 2017. The Chair invited MAC members to give their thoughts on the proposal. Mr Sharafi noted that AEMO had identified an error in the proposed amendments to clause 2.24.2. Only the first of the three proposed changes from “the IMO” to “AEMO” was correct, as the clause refers to the IMO’s budget, not AEMO’s budget. The Chair agreed that the drafting should be amended as proposed by Mr Sharafi. The MAC supported the progression of RC_2017_10 using the Fast Track Rule Change Process, subject to the agreed change to the drafting of clause 2.24.2.	
7	**Update on AEMO’s Market Procedures** Mr Sharafi noted that AEMO had decided to delay a discussion of changes to the Power System Operation Procedure (PSOP): Communications and Control Systems (originally scheduled for the AEMO Procedure Change Working Group meeting on 19 December 2017), so that it could be considered concurrently with corresponding changes to the IMS Interface Market Procedure – Network Operators and AEMO. The MAC noted the update on AEMO’s Market Procedures.	
8	**Implementation Plan – Security Constrained Market Model (verbal update)** Ms Varma and Mr Ashwin Raj provided an update on the implementation plan for the Government’s electricity sector reform work program. Ms Varma advised that the PUO preparing a briefing for the Minister’s consideration in January 2018 that would include an update of the policy positions set out in the Electricity Market Review’s Final Report: Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms (EMOP Final Report). The PUO intended to come back to the MAC in February-March 2018 with further details of the updated policy positions, subject to endorsement by the Minister. Mr Raj noted that the release of two consultation papers originally scheduled for late 2017 had been delayed. The revised plan was to send the papers to the Minister in January 2018 and seek approval to release them for public consultation in February or March 2018. The first paper outlines the policy positions on the reforms needed to implement constrained network access, and includes changes to the network connections and access framework as well as the complementary market reforms mentioned by Ms Varma. Mr Raj noted that the PUO would only seek feedback on the policy positions relating to reforms to the connections framework, as there had been considerable consultation on the market reforms during 2016. The PUO will seek the Minister’s endorsement of the market reform policy positions in the consultation paper in January 2018. Ms Varma clarified that the PUO intends to consult on any market reform policy positions that varied from the policy positions set out in the EMOP Final Report (e.g. regarding gate closure times).	

	The second consultation paper outlines the proposed methodology, data and assumptions for the financial modelling to estimate the impact of the introduction of constrained network access on existing Market Participants. The PUO intends to release the results of the modelling in a subsequent paper. The following points were discussed. • In response to a question from Ms Ng, Mr Raj advised that the PUO planned a one month consultation period for the two papers. Mr Raj suggested that stakeholders contact the PUO if they considered this period was insufficient. • Mrs Papps questioned the impact of the delay in releasing the consultation papers on the original intention to introduce legislation into Parliament by mid-2018. Mr Raj replied that the legislation was now more likely to be introduced to Parliament in the third quarter of 2018. • There was discussion about how the design work undertaken by the EMOP project and the EMOP Consultation Group after the publication of the EMOP Final Report would be incorporated into the update of the market reform policy positions. • Mrs Papps noted that the EMOP Final Report assumed the use of AEMO’s National Electricity Market Dispatch Engine (NEMDE). Mrs Papps expressed concern about a lack of consultation on this decision and suggested that further consideration should be given to whether NEMDE was the most appropriate system for use in the WEM. There was discussion about how and by whom the decision on the dispatch engine should be made, and on the interdependencies between the market design and the choice of dispatch engine. • Mr Chin asked for an update on the PUO’s intentions regarding the firm network access rights of existing Market Generators. Mr Raj advised that this would be included in the first consultation paper for stakeholder review and comment. • Mr Alex Penter asked how development work on the security constrained market model was being funded. Mr Raj replied that the policy work was being funded by Government.	
9	**Update on the Market Rules Issues List** The Chair noted that in the previous MAC meeting members identified six potential Rule Change Proposals in the MAC Market Rules Issues List. The Chair invited each of the submitters of these issues to give a short summary of their issue and proposed solution. <u>Issue 13: Use of data for monitoring and compliance</u> Mr Adrian Theseira noted that although issue 13 was raised by AEMO, it was really an ERA issue. Currently AEMO is required to provide running transactional data and other information to the ERA under section 2.16 of the Market Rules. The information, which includes the information specified in the Market Surveillance Data Catalogue (MSDC), is used by the ERA to support its monitoring of the effectiveness of the market under section 2.16.	

	Mr Theseira noted that since 1 July 2016 the ERA has also been responsible for compliance monitoring. Obviously the transactional data provided under section 2.16 would also be useful for compliance monitoring purposes, but a restriction in section 2.16 prevents any information gathered under that section from being used by the ERA for any other function. Mrs Papps expressed Alinta's general concern with the use of information for multiple purposes. Mrs Papps considered that when a participant provides data, knowing the intended use of the data is important because it allows the participant to structure how they present the data, so use of the data for other things such as compliance monitoring is a concern for Alinta. Mr Theseira noted that the ERA was predominantly interested in being able to use the transactional data in the MSDC. Mr Theseira was unsure whether the ERA would want to extend the scope of a Rule Change Proposal to cover other information provided by participants to the ERA under section 2.16. Mrs Papps advised that while she would be very much against the broader scope, her view on the information in the MSDC might be slightly different, subject to further review of the contents of the MSDC. Mr Will Bargmann considered that if the ERA wished to use data collected under section 2.16 for compliance purposes, then it should seek consent from the relevant participant on a case by case basis, so that the participant can ensure that it submits the appropriate data. <u>Issue 43: SRMC investigation process</u> Mr Theseira noted that issue 43 involved a similar data restriction problem to issue 13. A link was broken in section 2.16 of the Market Rules when the ERA received its new compliance function on 1 July 2016. Previously, when the IMO identified an SRMC matter, it would refer it to the ERA. After the ERA had investigated the matter it would refer it back to the IMO to take a case to the Electricity Review Board (ERB). All these steps were included in section 2.16. However, the step relating referral of the matter to the ERB was removed from section 2.16 on 1 July 2016. Mr Theseira advised that as a result, if the ERA has concerns following an SRMC investigation under section 2.16 and wants to take further action, it must do so under section 2.13. This effectively means that the ERA is required to conduct a new investigation under section 2.13, due to the restrictions on the use of information collected under section 2.16. Mr Theseira considered that this is not an efficient arrangement, and suggested re-inserting the step allowing referral to the ERB into section 2.16. Mrs Papps questioned whether the removal of the link in section 2.16 might be regarded as a manifest error arising from the Minister's amending rules. After some discussion there was general agreement that it would be preferable to progress the change using the Standard Rule Change Process. Ms Laidlaw asked whether the MAC had any concerns about the progression of Rule Change Proposals to address issues 13 and 43. Mr Stevens considered the current arrangements did not make	

	sense and so the proposals should be progressed to allow the ERA to do its job effectively. Mrs Papps agreed the proposals should be progressed, subject to her earlier comments. <u>Issue 14/36: Changes to capacity refund arrangements</u> Mr Daniel Kurz considered that while the current dynamic refund methodology goes some way toward reducing the punitive nature of capacity refunds, the impact of the refunds can still be large, particularly with reducing capacity margins, and the mechanism may not be appropriate for a baseload generator that is always running. Ms Ng added that her issue was that the dynamic refund arrangements can still be quite punitive, as the six times multiplier is no longer restricted to a few months of the year. Mr Chin considered the fundamental question was whether the refund methodology was overly punitive and therefore creating unnecessary and inefficient costs (such as increased insurance premiums) that are then passed through to consumers. Ms Laidlaw noted the new dynamic refund mechanism had only been in place since October 2017, and questioned how the effectiveness of a mechanism that had been in place for such a short time could be reasonably assessed. Ms Laidlaw considered that given the amount of consultation and effort involved in the development of the dynamic refund mechanism and the other urgent problems facing the market, it may not be reasonable to consider further changes to refunds before any evidence is available to suggest that the new mechanism is not working. Mr Ditric noted the dynamic refund methodology rule change also reallocated refund payments from Market Customers to Market Generators. The rationale for the latter change was that Market Generators were affected by additional capacity due to a reduction in the Capacity Price, and so should receive compensation if that capacity was then not made available. Mr Ditric considered that any changes to refund rates should be consistent with this rationale and the Reserve Capacity Mechanism as a whole. Ms Ng considered that, given the pending retirement of 380 MW of Synergy fleet and the growth of renewable generation, the refund rate may start to reach the six times limit very quickly. Mr Ditric replied that the original proposal was for a 12 times limit. There was some discussion about the level of the maximum refund rate originally proposed by the Lantau Group, and whether high refund rates were needed to ensure that Market Generators took all reasonable steps to avoid Forced Outages. Ms Ng agreed that it may be too early to reconsider the refund methodology, but reiterated her view that a six times multiplier is potentially punitive. Mr Stevens suggested that to progress a Rule Change Proposal it would be necessary to present evidence to show that the new dynamic refund rates were inefficient. Mr Chin asked if there was any publicly available literature explaining the arguments for setting the maximum refund rate at six times the Reserve Capacity Price. Ms Laidlaw replied that the documentation produced by the Reserve	

	Capacity Mechanism Working Group was available on the Rule Change Panel's website. Mr Peake suggested investigating whether private generators' insurance premiums increase in response to the implementation of the dynamic refund methodology. Mr Peake also suggested reviewing Forced Outages over the last five years to assess in which cases the responsible Market Generator's behaviour could have been affected by having a large refund multiplier. Mr Peake also considered that smaller participants were penalised by the allocation of refunds to Market Generators, as a smaller Market Generator paying a refund would receive a smaller proportion of that refund back from the market than a larger Market Generator with multiple Facilities. The Chair summarised that while it was not really possible to dismiss the issue, it was up to Bluewaters and/or ERM Power to provide a justification for further changes to the new dynamic refund methodology at this time. Otherwise, the Chair considered it might be best to defer looking at the issue until the new rules had been in effect for long enough to allow their assessment. Mr Chin proposed to discuss the options internally and then advise RCP Support about how and whether Bluewaters wished to proceed on the issue. <u>Issue 18: Short-term enhancements to the Spinning Reserve procurement process</u> Mr Kurz and Mr Chin explained their concern that if the ERA published a high draft margin values determination, then Market Generators did not have an opportunity to offer additional Spinning Reserve capacity to the market to try to reduce the overall Spinning Reserve cost. Bluewaters sought the opportunity to respond to the draft margin values determination and amend its contract offering where this would reduce the overall costs of Spinning Reserve to the market. Mr Sharafi noted that AEMO had requested expressions of interest for additional Spinning Reserve capacity and received some feedback. AEMO was currently working on how much more Spinning Reserve could be assigned to other non-Synergy providers. In response to a question from Mr Stevens, Mr Sharafi noted that the procurement of Spinning Reserve was a complex and circular process. Mr Chin asked whether the procurement process could be improved without a rule change. Mr Sharafi replied that AEMO believed participation of non-Synergy Generators could be expanded under the current Market Rules. Mr Kurz and Mr Chin stressed that a Market Generator's commercial decision to offer Spinning Reserve was affected by the applicable margin values (or draft margin values). Mr Chin suggested that it would be helpful for Market Generators if the ERA included a sensitivity analysis in its draft margin values determination, which indicated the effect on the margin values of more or less contracted Spinning Reserve. Mr Chin considered that this would provide a	

	useful price signal to participants and promote greater efficiency in the provision of Spinning Reserve. Ms Laidlaw commented that the timing of any contracting would need to be carefully coordinated with the margin values determination process, as the quantity of Spinning Reserve provided by contract would affect the final margin values for a Financial Year. Mr Stevens considered that in hindsight it would have been preferable to implement a Spinning Reserve market before the LFAS Market, because of its comparative simplicity and the greater number of potential providers. Mr Sharafi noted that for next year AEMO had started to see how much interest there is in the market to provide Spinning Reserve, and would use this information to establish a marginal price for change. Mr Sharafi suggested that AEMO provide an update on the issue at either the next Generator Forum or the next MAC meeting. Ms Laidlaw noted that it was still unclear whether there was any need for a Rule Change Proposal to address Bluewaters' concerns. Mr Sharafi agreed to come back to the MAC on whether AEMO was able to do the things suggested by Bluewaters under the current Market Rules, or whether a Rule Change Proposal would be required.	
	Action: AEMO to investigate and report to the MAC on whether a rule change is needed to improve efficiency in the Spinning Reserve procurement process by allowing Market Generators to offer additional Spinning Reserve in response to the draft margin values determination.	**AEMO**
	<u>Issue 20/38: Spinning Reserve Cost Allocation</u> Mr Kurz noted that Bluewaters' proposal was to modify the 200 MW boundary for Block 1 in Appendix 2 of the Market Rules (Spinning Reserve Cost Allocation), as the setting of the boundary at this level was a limiting factor and imposed a large step change in Bluewaters' SRMC. Mr Kurz was aware of the intention to move to a full runway model for Spinning Reserve cost allocation in the longer term, but questioned whether in the shorter term there was any need to maintain the 200 MW boundary or whether it could be set to a higher value. Ms Laidlaw noted previous MAC discussions on the issue had concluded that changes to the modified runway model block sizes only shifted costs from some specific generators to others, but did not address the fundamental problems with the methodology. Ms Laidlaw considered that as the full runway model resolved the underlying problem it may be difficult to justify a rule change that was limited to modifying the block sizes, noting that AEMO had indicated at the previous MAC meeting that it would be feasible for AEMO to implement a full runway model in advance of other major energy market reforms. Mr Chin suggested that a change to increase the 200 MW boundary would deliver material efficiency benefits and could be implemented faster than the full runway model. Mr Stevens considered that the full runway model was the more efficient option and was also likely	

	to be the faster option to implement, as it was generally supported by the market. There was some discussion about how Bluewaters' suggested change would affect the distribution of Spinning Reserve costs among Market Generators. Ms Laidlaw suggested that when MAC members provided their suggested urgency rating for this issue they should also provide an urgency rating for a Rule Change Proposal to implement the full runway model. Mrs Papps noted that Alinta would support the full runway model as the more appropriate solution, and suggested bringing that option forward as soon as possible. <u>Issue 31: Removal of Synergy LFAS Report obligation</u> Mr Bargmann noted that the Market Rules require Synergy to give AEMO ex-post information regarding which Facilities actually provided LFAS in each Trading Interval. The requirement was originally designed to allow the IMO to check which Facilities actually provided LFAS and compare those Facilities with those Synergy expected to provide LFAS when it made its Balancing Submissions. Synergy's issue is that because System Management is Synergy's dispatch agent, AEMO already has the information on which Facilities provide LFAS by virtue of the fact that System Management is now a part of AEMO. This means that the required reports serve no purpose, as Synergy does not have any relevant information that AEMO does not already have. In response to a question from Mr Stevens, Mr Sharafi confirmed that AEMO had all the information required and did not need Synergy to provide the report. No concerns were raised by MAC members about the progression of a Rule Change Proposal to address Synergy's issue. <u>Request for Feedback</u> Ms Laidlaw asked MAC members and observers for feedback on each the issues discussed, as well issue 17 (in case it cannot be included in RC_2014_03) and the implementation of a full runway model for Spinning Reserve cost allocation. For each issue, the requested feedback included what urgency rating they would suggest for a Rule Change Proposal to address the issue (including an urgency rating of zero, meaning that the proposal should not be progressed); and whether the respondent's organisation would be interested in developing a Rule Change Proposal to address the issue. Ms Laidlaw noted that RCP Support intended to collate the information received, obtain a preliminary urgency rating for each issue from the Rule Change Panel, and then publish the results for the consideration of stakeholders.	
	Action: MAC members and observers to provide feedback on each of the six issues identified by the MAC as potential Rule Change Proposals (13, 14, 18, 20, 31 and 43) and issue 17 (in case it cannot be included in RC_2014_03), regarding what urgency rating they would suggest for a Rule Change Proposal addressing the issue (i.e. Essential, High, Medium, Low,	**All**

	Housekeeping or Don't Progress); and whether their organisation is interested in developing a Rule Change Proposal to address the issue.	
10	**General Business** <u>MAC Meeting Schedule for 2018</u> The MAC noted the proposed meeting schedule for 2018. The Chair advised that the schedule was still to be formally approved by the Rule Change Panel, but requested MAC members block out the relevant meeting dates in their calendars. Mrs Papps asked whether MAC members would be agreeable to starting MAC meetings earlier in the day. Although some members indicated that starting the meetings in the morning would be problematic, several expressed support for a 12:00-12:30 PM start. ***Action: MAC members to advise RCP Support whether they would have any problems with starting MAC meetings at 12:00 PM or 12:30 PM rather than 1:00 PM.*** <u>MAC Composition Review for 2017 and Call for Nominations for 2018</u> The Chair noted that the terms of two MAC members expire in 2018: Dr Steve Gould (Market Customers) and Mr Stevens (Market Generators). Mr Richard Cheng noted that nominations for the open positions were due by Friday, 29 December 2017. The Rule Change Panel was expected to make a decision on the new appointments in February 2018, and both incoming and outgoing members would be invited to attend the March 2018 MAC meeting.	 **All**

The meeting closed at 4:00 PM.

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 4: MAC Action Items

Meeting 2018-02 – 14 February 2018

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/progress
19/2017	The PUO to consult with AEMO and RCP Support on how to address the concerns raised by MAC members about the 2017/03 Amending Rules and develop a proposal for consideration at the next MAC meeting.	PUO/AEMO/ RCP Support	August 2017	Open
28/2017	AEMO to investigate and report to the MAC on: (a) the timing and content of the information provided to Market Participants on dynamic refund rates under the Market Rules; (b) whether the required information is currently provided in accordance with the Market Rules, and, if not, when it is expected to be; and (c) any options to improve the content and/or timeliness of the information provided to Market Participants on dynamic refund rates.	AEMO	November 2017	Open
29/2017	The ERA to provide an update to the MAC on the proposed order and timing of the upcoming periodic market reviews that the ERA is required to conduct under the Market Rules.	ERA	November 2017	Open

Item	Action	Responsibility	Meeting arising	Status/progress
31/2017	AEMO to investigate and report back to the MAC on the simplest and cheapest option for changes to ensure that the late logging of a Forced Outage by a Generator would result in the appropriate settlement adjustment outcomes (i.e. correct payment of capacity refunds and the recovery of any unwarranted constrained off compensation).	AEMO	November 2017	Open
32/2017	RCP Support to provide an update to the MAC on the new fast track process discussed by the EMOP Consultation Group in 2016.	RCP Support	November 2017	Closed
33/2017	The PUO to review the current list of Protected Provisions in the Market Rules to determine if any of the provisions no longer need to be Protected Provisions.	PUO	November 2017	Open
34/2017	AEMO to investigate what simple options might exist to improve the accessibility and timeliness of the information provided to Market Participants on LFAS and Spinning Reserve costs.	AEMO	November 2017	Open
36/2017	RCP Support to schedule preliminary MAC discussions covering the following topics: • the RCM (excluding its pricing mechanisms); • behind-the-meter issues; • the treatment of storage facilities in the WEM; • the basis for the allocation of Market Fees; • review of agency roles and responsibilities; • Commissioning Tests; and • forecast quality.	RCP Support	November 2017	Open
38/2017	RCP Support to publish the minutes of meeting 2017-07 on the Rule Change Panel's website as final	RCP Support	December 2017	Closed
39/2017	MAC members and observers to email RCP Support by 5:00 PM on Wednesday, 20 December 2017 to: • provide any feedback on the points raised in the 13 December 2017 presentation on RC_2014_03 (Administrative Improvements to the Outage Process); and	All	December 2017	Closed

Item	Action	Responsibility	Meeting arising	Status/progress
	• indicate whether they are interested in attending the proposed January 2018 workshop, and if so when they are available during that month			
40/2017	MAC members and observers to email RCP Support any feedback on the questions raised in the 13 December 2017 presentation on RC_2014_06 (Removal of Resource Plans and Dispatchable Loads) by 5:00 PM on Wednesday, 20 December 2017.	All	December 2017	Closed
41/2017	AEMO to investigate and report to the MAC on whether a rule change is needed to improve efficiency in the Spinning Reserve procurement process by allowing Market Generators to offer additional Spinning Reserve in response to the draft margin values determination	All	December 2017	Open
42/2017	MAC members and observers to provide feedback on each of the six issues identified by the MAC as potential Rule Change Proposals (13, 14, 18, 20, 31 and 43) and issue 17 (in case it cannot be included in RC_2014_03), regarding what urgency rating they would suggest for a Rule Change Proposal addressing the issue (i.e. Essential, High, Medium, Low, Housekeeping or Don't Progress); and whether their organisation is interested in developing a Rule Change Proposal to address the issue.	All	December 2017	Closed
43/2017	MAC members to advise RCP Support whether they would have any problems with starting MAC meetings at 12:00 PM or 12:30 PM rather than 1:00 PM.	All	December 207	Closed

Economic Regulation Authority

Working Schedule

5-yearly methodology reviews

July 2017 - Responsibility for conducting methodology reviews passed to ERA

Accompanied by market rule relaxing the timing of the reviews to recognise new obligation for ERA

Economic Regulation Authority

Methodology reviews:

- **Ancillary Service Requirements**
- **BRCP and EPL Methods**
- **BRCP Market Procedure**
- **Outage Planning Process**
- **Planning Criterion and Load Forecasting Process**
- **Relevant Level Method**

Economic Regulation Authority

Review	Previous	Next one due	About
Ancillary Service Requirement	2014	~~Nov 2019~~ TBA	Technical requirements for providing ancillary services in the WEM and basis for setting the ancillary service requirement in the WEM
BRCP and EPL Methods	2013	~~Oct 2018~~ TBA	Approach to determining the maximum price limits for the capacity and electricity markets respectively
BRCP Market Procedure	2012	~~Jun 2016~~ TBA	Procedure undertaken to calculate capacity and electricity price limits

Economic Regulation Authority

Review	Previous	Next one due	About
Outage planning process	2011	~~Oct 2016~~ TBA	Technical criteria SM uses to evaluate outage plans and process of engaging with Market Participants
Planning Criterion and forecasting process (LT PASA)	2012	~~Nov 2017~~ TBA	Sufficient capacity to meet forecast peak demand plus reserve margin. Forecasting process SWIS peak demand
Relevant Level Method	2014	By 1 Apr 2019	Determination of certified capacity for intermittent generators

Economic Regulation Authority

Factors affecting timing of next reviews:

- **EMR allowed additional time for ERA to conduct reviews given these are a new obligation (1.17.5).**
- **Planned energy reforms – constrained network access, co-optimized energy and ancillary service markets, facility bidding**
- **Consultation on capacity procurement – to Sep 2018**
- **Resourcing**

Economic Regulation Authority

By end Dec 2018: Relevant Level Method

- **Complies with transitional arrangements for transfer of functions from IMO to ERA**
- **ERA to review method by 1 April of second year of specified period, e.g. 1 April 2019**
- **Finishing the review by end Dec 2018 allows 3 months for any associated rule changes**

Economic Regulation Authority

By end Jun 2019: BRCP/EPL Methods and BRCP Market Procedure

- **Address concerns raised by market in responses to EPL and BRCP approvals (last couple of years)**
- **PUO will have completed consultation on capacity procurement/design of RCM**
- **Market significance:**
  - **estimate capacity credit revenue; and**
  - **investment signals for private sector investment in new generation**

Economic Regulation Authority

By end Dec 2019: Planning criterion and peak demand forecasting

- **Increasing levels of intermittent generation particularly behind the meter**
- **Changing customer behaviour**
- **Effect of new technologies entering the market**
- **Drives the efficient level of capacity in the market**

Economic Regulation Authority

2020:

- **Outage Planning process**
  - **Subject to rule changes at present**
  - **Recommendations from previous review have not yet been implemented**
  - **Outages can drive up electricity prices**
- **Ancillary Service Requirements**
  - **Relationship to co-optimized energy and ancillary service market design**

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	Jul – Dec 2018	Jan – Jun 2019	Jul – Dec 2019	2020	
Project prep	Relevant Level	Rule change			
	Project prep	EPL/BRCP	Rule change		
		Project prep	Planning criterion/LT PASA	Rule change	
				Outage planning process	
					Ancillary Services requirements

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Stakeholder engagement:

- **Required by the Market Rules for all reviews**
- **Understand implications for participants**
- **Discuss further at ERA Stakeholder Workshop**
  - **Timing**
  - **Process**

Economic Regulation Authority

The Effectiveness of the Synergy Regulatory Scheme

2016 Report to the Minister for Energy

Natalie Robins

Principal Analyst

Economic Regulation Authority

The Synergy (EGRC) Regulatory Scheme

- 1 January 2014, merger of Verve Energy and Synergy.
- Scheme requirements:
  - Segmentation;
  - Internal transfer pricing;
  - Standard products;
  - Non-discrimination
  - Audit and review; and
  - ERA reviews effectiveness of scheme annually.

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2016 Retail and Wholesale Competition

- Substantial increase in energy market price volatility;
- Synergy sets energy prices 84% of time.
- Demand for customised products but only one standard product sold;
- Competition in contestable retail market between six main participants, with generation assets to self hedge;
- Small retailers exposed to energy market volatility;
- Synergy dominant (owns or controls 74%).

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Wholesale Arrangements

- Previously, transfer pricing based on past contracts and budgets.
- Revisit transfer pricing every 3 years.
- From 1 July 2017 an energy forward curve (Synergy's forecast of future energy market prices) used to calculate foundation and additional transfer prices.
- Also underlies calculation of standard product prices.
- Must also underlie customised products.

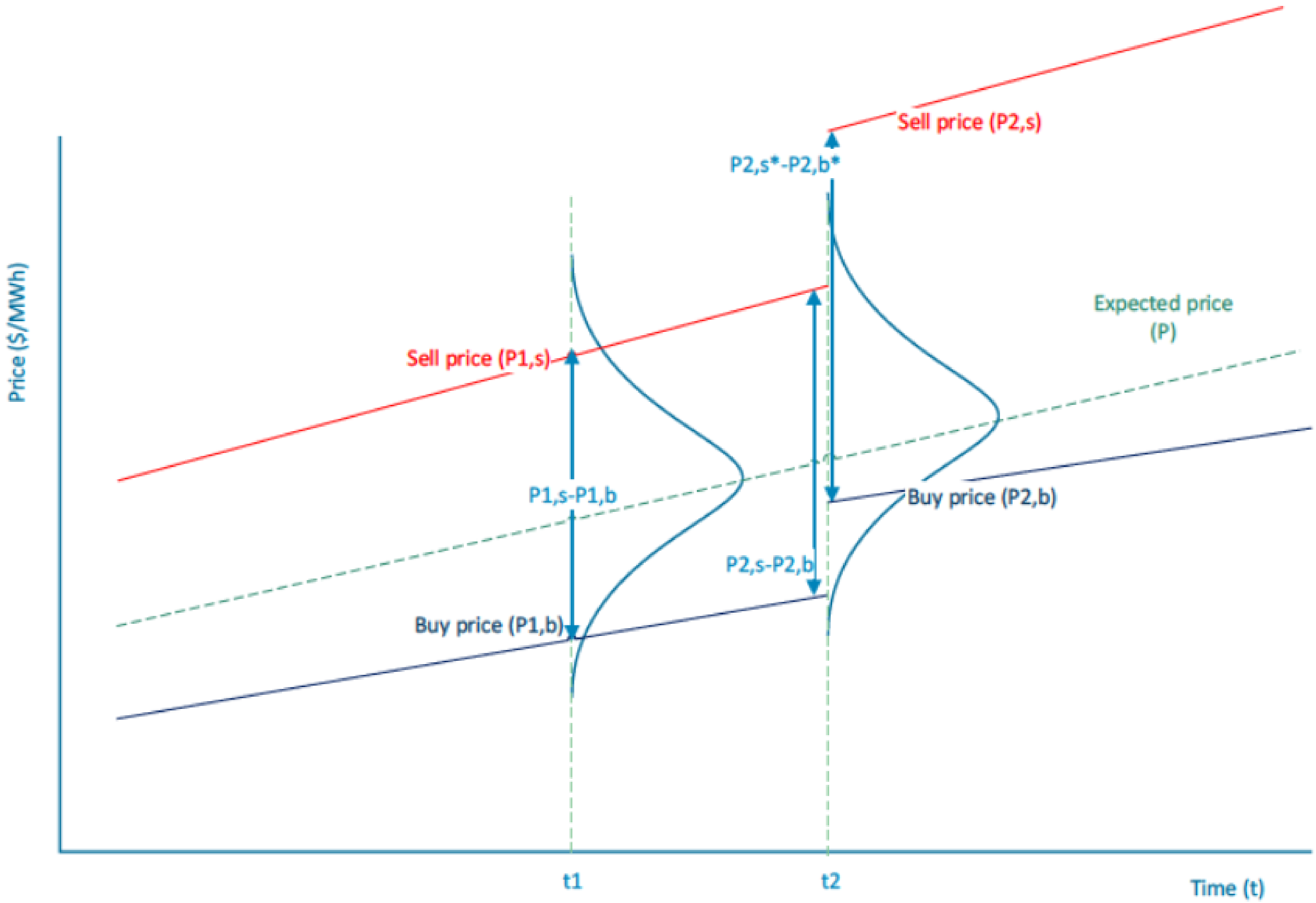
Economic Regulation Authority

Efficient pricing in the WEM depends on

- Pricing at short run marginal cost in energy markets;
- Reliable and efficient forecasting of future energy market prices by Synergy;
- The buy/sell spread – which constrains Synergy's pricing of bilateral contracts.

- **set a narrower spread of 10 percent between buy and sell price to ensure that pricing discipline is placed on Synergy.**

Figure 2. Buy–sell spread and relationship to expected price*



Economic Regulation Authority

RBU Involvement in Setting Forward Energy Curve

- RBU involvement in setting contract prices may confound the ring fencing requirements;
- Stakeholders may not be aware of the replacement transfer pricing method.
- There is no requirement for Synergy to inform the ERA to allow for regulatory scrutiny

- **Synergy publishes its foundation transfer price and the method it uses for calculating this price.**

Standard Product Arrangements

- Credit requirements burdensome and intrusive;
- Specifications too rigid; and
- Asymmetric force majeure provisions.

- **Relax credit requirements so they are proportionate to Synergy's exposure to risk of counterparty default;**
- **Review and amend standard product specifications and force majeure clauses**

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Segment Financial Reporting

- No requirement to separate gas and electricity or contestable and non-contestable financial results.

- **Synergy to produce consolidated segmental financial reports. Information to be treated as 'commercial in confidence.'**

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Questions / comments?

Economic Regulation Authority

2016/17 WEM Report

MAC update Feb 2018

Effectiveness of the WEM in meeting market objectives

Sent to the Minister on 15 Dec 2017

Published 12 Jan 2018

Economic Regulation Authority

Context for 2016/17 report:

- **Uncertainty in the energy sector**
- **To support the effective operation of the WEM**
  - **Issues requiring urgent attention**
  - **Transitional changes under way and emerging**
- **March 2017 – Stakeholder workshop**
- **July 2017 – Discussion paper (10 subs)**

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Key themes from feedback:

- Support for reforms announced in Aug
- Agency roles and the reform process
- Policy uncertainty - RCM and renewables
- Maintaining security and reliability
- Competition and market power
- FRC

Focus of the report:

- **Theme 1 – downward pressure on wholesale electricity costs**
- **Theme 2 – addressing risks to security and reliability in the market**
- **Theme 3 – developing a market design fit for purpose**

Wholesale electricity costs:

- **Cost trends**
- **Limited wholesale competition**
- **Competitive wholesale is requirement for effective retail competition**
- **Pricing discipline – SRMC and EGRC**

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Security and reliability:

- **Proposed reforms – market efficiency**
- **Generation adequacy**
- **Governance of system security and reliability**

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Fit for purpose market design:

- **Accommodate technical change**
- **System dynamics and pricing signals**
- **Timing and pace of reform**
- **Agency roles and responsibilities**

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 6(a): Overview of Rule Change Proposals

Meeting 2018-02 – 14 February 2018

- Changes to the report provided at the previous MAC meeting are shown in red font.
- The next step and the timing for the next step is provided for Rule Changes that are currently being actively progressed by the Rule Change Panel.
- Timing is listed as TBD for all Rule Change Proposals that are not currently being actively progressed. The Rule Change Panel is developing a resource plan that will allow it to provide more accurate next steps and timing for next steps for these Rule Change Proposals.
- A new table has been added to the report to indicate potential Rule Change Proposals that are in the Pre-Rule Change Proposal stage.

Formally Submitted Rule Change Proposals (as at 7 February 2018)

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
Rule Change Proposals awaiting Approval by the Minister						
RC_2017_05	07/07/2017	AEMO	AEMO Role In Market Development	High	Final Rule Change Report published (20/12/2017), awaiting Minister's approval.	20/02/2017
Standard Rule Change Proposals with Second Submission Period Open						
None						
Standard Rule Change Proposals with First Submission Period Closed						
RC_2014_06	28/01/2015	IMO	Removal of Resource Plans and Dispatchable Loads	Medium	Close of the Call for Further Submissions	13/02/2018

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
RC_2014_03	27/01/2014	IMO	Administrative Improvements to the Outage Process	High	Publish a Call for Further Submissions	01/03/2017
RC_2013_15	24/12/2013	IMO	Outage Planning Phase 2 – Outage Process Refinements	Medium	Publication of Draft Rule Change Report	TBD
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	TBD
RC_2014_09	13/03/2015	IMO	Managing Market Information	Low	Publication of Draft Rule Change Report	TBD
RC_2015_01	03/03/2015	IMO	Removal of Market Operation Market Procedures	Low	Publication of Draft Rule Change Report	TBD
RC_2015_03	27/03/2015	IMO	Formalisation of the Process for Maintenance Requests	Low	Publication of Draft Rule Change Report	TBD
RC_2017_02	04/04/2017	Perth Energy	Implementation of 30-Minute Balancing Gate Closure	Medium	Publication of Draft Rule Change Report	TBD
Standard Rule Change Proposals with Second Submission Period Closed						
RC_2017_06	17/07/2017	AEMO	Reduction of the prudential exposure in the Reserve Capacity Mechanism	High	Rule Change Panel to consider the Final Rule Change Report	22/02/2018
RC_2017_10	18/01/2018	Rule Change Panel	Correction of Gazettal Errors	High	Rule Change Panel to consider the Final Rule Change Report	15/02/2018
RC_2014_07	22/12/2014	IMO	Omnibus Rule Change	Low	Publication of Final Rule Change Report	TBD
RC_2014_10	13/01/2015	IMO	Provision of Network Information to System Management	Superseded	Publication of Final Rule Change Report	TBD

Rule Change Proposals Commenced since the last MAC Meeting

Reference	Submitted	Proponent	Title	Commencement
None				

Gazetted Rule Changes not yet Commenced

Gazette		Content	Commencement
Number	Date		
2016/89	31/05/2016	Wholesale Electricity Market Amending Rules 2016, Schedule B, Part 4 *Further changes to the Reserve Capacity Mechanism involving Reviewable Decisions*	A time specified by the Minister in a notice published in the *Gazette*

Potential Rule Changes in the Pre-Rule Change Proposal Stage

Reference	Proponent	Description	Next Step	Timing
RC_2018_01	Rule Change Panel	New Notional Wholesale Meter Manifest Error	The Rule Change Panel will consider submitting a Rule Change Proposal after consideration by the MAC	14/02/2018

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 6(b): RC_2018_01 (New Notional Wholesale Meter Manifest Error) – Pre-Rule Change Proposal

Meeting 2018-02 – 14 February 2018

1. Background

An issue was raised at the 8 November 2017 Market Advisory Committee (**MAC**) meeting regarding a manifest error in how Non-Interval Meter Growth is calculated in Step 5A of Appendix 5 for the purposes of determining a Market Customer's Individual Reserve Capacity Requirement. The manifest error relates to the calculation of Non-interval Meter Growth, which currently prescribes that the growth of non-interval meters is limited to that which occurred within Trading Month n-3 only, not the net growth over the period from the end of the preceding Hot Season up to the end of Trading Month n-3.

RCP Support sought feedback on this issue. Eight of the nine responses agreed that this is a manifest error, whilst the other response suggested that this issue not be progressed as a manifest error due to the lack of information and time to assess the impact and perform a cost benefit analysis.

Consequently, RCP Support has developed a Pre-Rule Change Proposal, to be proposed by the Rule Change Panel, seeking to amend Step 5A of Appendix 5 in the Market Rules to calculate the growth of non-interval meters from the end of the preceding Hot Season up to the end of Trading Month n-3. This will provide a more consistent approach to evaluating the growth of meters for Individual Reserve Capacity Requirement calculations and will remove a cross-subsidy that non-interval meter Market Participants provide to Synergy.

2. Recommendation

It is recommended that the MAC:

- support progressing this Pre-Rule Change Proposal (once finalised by the Rule Change Panel) under the fast track rule change process; and
- support the proposed drafting of this Rule Change Proposal and provide any feedback or amendments to RCP Support.

RCP Support will discuss the Pre-Rule Change Proposal including the MAC's feedback with the Rule Change Panel at its meeting on 22 February 2018.

RCP | Rule Change Panel

Wholesale Electricity Market Rule Change Proposal

Rule Change Proposal ID: RC_2018_01
Date received: *[to be filled in by the RCP]*

Change requested by:

Name:	Rule Change Panel
Phone:	
Email:	
Organisation:	Rule Change Panel
Address:	
Date submitted:	*<date submitted to the RCP>*
Urgency:	High
Rule Change Proposal title:	New Notional Wholesale Meter Manifest Error
Market Rule(s) affected:	Appendix 5 Step 5A

Introduction

Clause 2.5.1 of the Wholesale Electricity Market (**WEM**) Rules (**Market Rules**) provides that any person may make a Rule Change Proposal by completing a Rule Change Proposal form that must be submitted to the Rule Change Panel.

This Rule Change Proposal can be sent by:

Email to: rcp.secretariat@rcpwa.com.au

Post to: Rule Change Panel
Attn: Executive Officer
C/o Economic Regulation Authority
PO Box 8469
PERTH BC WA 6849

The Rule Change Panel will assess the proposal and, within 5 Business Days of receiving this Rule Change Proposal form, will notify you whether the Rule Change Proposal will be further progressed.

In order for the proposal to be progressed, all fields below must be completed and the change proposal must explain how it will enable the Market Rules to better contribute to the achievement of the Wholesale Market Objectives.

The objectives of the market are:

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;

(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

Details of the Proposed Rule Change

Describe the concern with the existing Market Rules that is to be addressed by the proposed rule change:

Background

AEMO determines the Individual Reserve Capacity Requirement (**IRCR**) for every Market Customer for each Trading Month. Market Customers must acquire Reserve Capacity Credits based on their share of the total IRCR of all Market Customers.

A Market Customer's IRCR is calculated using the methodology specified in Appendix 5 of the Market Rules for each Trading Month, and uses Meter Registry data (including details of the responsible party for each meter) and the associated energy data. This means that for every day, a meter is attributed to a Market Customer as the responsible party and that Market Customer incurs IRCR liabilities related to that meter, with a time lag of three calendar months.

Issue

The Rule Change Panel has identified a manifest error in the method for annually setting and monthly adjustment of IRCRs as set out in Appendix 5 of the Market Rules. The methodology currently:

- accounts for all new interval meters that were not registered during all of the "preceding Hot Season"[1] but were registered by the end of Trading Month n-3 (Step 5 of Appendix 5); but
- only accounts for the growth of non-interval meters in Trading Month n-3 (Step 5A of Appendix 5).

[1] The "preceding Hot Season" is defined in Step 1 of Appendix 5 as the Hot Season preceding the initial calculation of IRCR for a Reserve Capacity Cycle.

The current operation of Step 5 of Appendix 5 is to identify meters that were:

(a) not registered with AEMO during one or more of the 12 peak South West interconnected system (**SWIS**) Trading Intervals in the "preceding Hot Season"; and

(b) were registered by the end of Trading Month n-3.

Each of these identified new meters contributes to the relevant Market Customer's IRCR.

Step 5A of Appendix 5 determines the calculation of the "New Notional Wholesale Meter's" contribution to IRCR, which is intended to account for new non-interval meters that did not exist during the 12 peak SWIS Trading Intervals of the relevant "preceding Hot Season".

Step 5A was introduced by Rule Change Proposal RC_2008_32: Calculation of IRCR[2], which was developed by the Independent Market Operator (**IMO**) based on the recommendations of the IRCR Working Group. The Working Group had concluded "that new non-interval meters entering the Notional Wholesale Meter were not being treated in the same way as new interval meters for the purposes of IRCR and that this should be corrected. Accordingly it was decided that a rule change proposal be drafted to address this inequality."

The operation of the relevant parts of Step 5A of Appendix 5 is as follows:

(a) calculate the "Median Notional Wholesale Meter" by doubling the median value of metered consumption for the Notional Whole Meter during the 4 peak SWIS Trading Intervals of Trading Month n-3;

(b) divide the "Median Notional Wholesale Meter" by the number of non-interval or accumulation meters that existed at the end of Trading Month n-3 to find the "Average Non-Interval Meter";

(c) subtract the number of non-interval or accumulation meters disconnected during Trading Month n-3 from the number of non-interval or accumulation meters connected over the same period to determine the "Non-Interval Meter Growth" (see below for commentary);

(d) multiply the "Non-Interval Meter Growth" (c) by the "Average Non-Interval Meter" (b) to arrive at the "New Notional Wholesale Meter"; and

(e) set the "New Notional Wholesale Meter" as designated in Appendix 5.

Therefore, the non-interval meter growth for the "New Notional Wholesale Meter" only accounts for the net growth during a single Trading Month (n-3), and does not include the net growth of non-interval meters prior (starting from the "preceding Hot Season"). Relative to Step 5 of Appendix 5, which identifies all new interval meters that were not registered for all of the 12 peak SWIS Trading Intervals but were registered by the end of Trading Month n-3, the Rule Change Panel considers that the failure of Step 5A of Appendix 5 to consider non-interval meter growth over all the months since the "preceding Hot Season" up to Trading Month n-3 is a manifest error in the Market Rules. A numerical example demonstrating the issue is detailed in Appendix 1.

As stated above, Appendix 5 is currently inconsistent with the originally proposed intent of RC_2008_32. Historically, Step 5A of Appendix 5 was developed by the IMO on the recommendations of the IRCR Working Group. The IRCR Working Group stated –

> "that new non-interval meters entering the Notional Wholesale Meter were not being treated in the same way as new interval meters for the purposes of IRCR and that this should be corrected. Accordingly it was decided that a rule change proposal be drafted

[2] See Rule Change: RC_2008_32 on the Economic Regulation Authority Western Australia website for details: https://www.erawa.com.au/rule-change-panel/market-rule-changes/rule-change-rc_2008_32.

to address this inequality" (RC_2008_32 – Original Submission)

Step 5A of Appendix 5 was introduced in Rule Change RC_2008_32 and commenced on 1 May 2009.

The RC_2008_32 Final Report stated that "… the addition of Step 5A in Appendix 5 [is] to bring about a more equitable treatment of non-interval or accumulation meters and interval meters in the calculation of a retailer's IRCR." This clearly demonstrates that the intention of RC_2008_32 was to provide better equity in the treatment of non-interval meters and interval meters which would include assessing the growth in new meters in a consistent fashion.

Although RC_2008_32 intended for Step 5A of Appendix 5 to level the treatment of non-interval and interval meters, the methodology for calculating the growth of non-interval meters inadvertently did not achieve this outcome, which is sought to be corrected by this Rule Change Proposal. Thus conceptually, the principle behind the calculation of the "Non-Interval Meter Growth" as defined in Step 5A of Appendix 5 departs from the principle used in Step 5 of Appendix 5, which determinatively demonstrates a manifest error.

Consultation

The issue with the "Non-Interval Meter Growth" in Step 5A of Appendix 5 was raised and discussed with the Market Advisory Committee (**MAC**) on 8 November 2017. The MAC was asked to provide further feedback on whether this issues is a manifest error, and eight of the nine responses received agreed that this part of Step 5A of Appendix 5 represents a manifest error. One response suggested that this issue should not be progressed as a manifest error due to the lack of information and time available to assess the impact and perform a cost benefit analysis.

The Rule Change Panel considers that Step 5A of Appendix 5 contains a manifest error given:

- the original intention of Step 5A of Appendix 5 in RC_2008_32;
- the conceptual difference of assessing the growth of non-interval meters for Step 5A of Appendix 5 relative to how Step 5 of Appendix 5 operates for new interval meters; and
- that the majority of the MAC respondents agreed that this issue is a manifest error.

Proposed Solution

This Rule Change Proposal seeks to change the calculation of Non-Interval Meter Growth in Step 5A of Appendix 5. The proposal is to calculate the growth of non-interval meters by subtracting the total number of non-interval meters disconnected over the period from the end of the preceding Hot Season up to the end of Trading Month n-3 from the total number of non-interval meters connected during the same time period. No other sections of the Market Rules are proposed to be amended.

Explain the reason for the degree of urgency:

The Rule Change Panel considers that this Rule Change Proposal should be progressed under the Fast Track Rule Change Process as it seeks to correct a manifest error (satisfying the condition in clause 2.5.9(b) of the Market Rules).

Also, the proposed Amending Rules should commence as soon as practicable to give effect to the original intention of Step 5A of Appendix 5, which will ensure that growth in interval and non-interval meters are treated fairly, which translates into more equitable IRCR calculations.

After consultation with AEMO, the current IRCR calculation in the Market Rules results in an approximate cross-subsidy to Synergy ranging from around 3MW/month to 10MW/month (figures rounded) based on 2016-17 Capacity Year figures, as Synergy is the only entity with non-interval meter customers. This Rule Change Proposal will reduce the cross-subsidy that Synergy receives from other Market Participants, and will cause IRCRs to be calculated in a consistent and fair manner for the entire market.

Provide any proposed specific changes to particular Market Rules: *(for clarity, please use the current wording of the rules and place a ~~strikethrough~~ where words are deleted and underline words added)*

NOTE – Appendix 5 will be more extensively modified in RC_2017_06 (Reduction of the prudential exposure in the Reserve Capacity Mechanism), and the changes proposed to Appendix 5 in this Rule Change Proposal do not overlap with those in RC_2017_06.

Appendix 5: Individual Reserve Capacity Requirements

…

STEP 5A: When determining the Individual Reserve Capacity Requirements for Trading Month n.

Find the MW figure formed by doubling the median value of the metered consumption for the Notional Wholesale Meter v*, during the 4 peak SWIS Trading Intervals of Trading Month n-3 ("Median Notional Wholesale Meter").

Divide the Median Notional Wholesale Meter by the number of non-interval or accumulation meters that existed at the end of Trading Month n-3 ("Average Non-Interval Meter").

Subtract the number of non-interval or accumulation meters disconnected between the end of the preceding Hot Season and the end of~~during~~ Trading Month n-3 from the number of non-interval or accumulation meters connected between the end of the preceding Hot Season and the end of~~during~~ Trading Month n-3 ("Non-Interval Meter Growth").

…

Describe how the proposed rule change would allow the Market Rules to better address the Wholesale Market Objectives:

The Rule Change Panel considers that the proposed amendments will better achieve Wholesale Market Objective 1.2.1(b) – '*to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;*' by ensuring the IRCR liability calculation is more equitably calculated as non-interval meter growth and interval meter growth will be accounted for more consistently and equitably.

Provide any identifiable costs and benefits of the change:

Based on consultation with AEMO, Synergy received a cross-subsidy ranging from about 3MW/month to 10MW/month (figures rounded) across the 2016-17 Capacity Year. Removal of this subsidy will benefit the market more generally as it will allow the IRCRs to be calculated more equitably.

This Rule Change Proposal will require internal process changes to keep a record of net non-interval meter growth per month. However, the Rule Change Panel considers that this is unlikely to be a significant change to AEMO's systems and is unlikely to have substantial associated costs, so this Rule Change should have a relatively short implementation time. [AEMO to confirm]

Appendix A. Numerical Illustration of the Issue with Step 5A of Appendix 5

The table below illustrates the issue with Step 5A of Appendix 5 numerically (figures are for illustrative purposes only and do not represent actual non-interval meter growth):

Period	Preceding Hot Season	Apr	May	Jun	Jul n-3= Apr	Aug n-3= May	Sep n-3= Jun	Oct n-3= Jul	Nov n-3= Aug	Dec n-3= Sep	Jan n-3= Oct	Feb n-3= Nov	Mar n-3= Dec	Apr n-3= Jan
Number of meters at end of period or Trading Month	10,000	10,100	10,200	10,300	10,400	10,500	10,600	10,700	10,800	10,900	11,000	11,100	11,200	11,300
Number of meters at end of Month n-3		n.a.	n.a.	n.a.	10,100	10,200	10,300	10,400	10,500	10,600	10,700	10,800	10,900	11,000
Net non-interval meter growth in Trading Month n-3 (as used in Step 5A of Appendix 5)		n.a.	n.a.	n.a.	100	100	100	100	100	100	100	100	100	100
Growth in non-interval meters between n-3 and the "preceding Hot Season"		n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	400	500	600	700	800	900	1,000
Difference in non-interval meter growth (actual vs calculated in Step 5A)		n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	***300***	***400***	***500***	***600***	***700***	***800***	***900***

For the first month of a Capacity Year, October, the New Notional Wholesale Meter is calculated based on the relevant information from Trading Month n-3, i.e. the preceding July. In this example, July has 10,400 non-interval meters registered by the end of the month which demonstrates a total growth of 400 non-interval meters from the preceding Hot Season. The growth of non-interval meters in Step 5A of Appendix 5 currently references the change *during Trading Month n-3 only* (i.e. only 100). Thus the actual growth in non-interval meters becomes understated as the year progresses, as the New Notional Wholesale Meter does not include non-interval meter growth of all relevant prior months.

RCP | Rule Change Panel
Market Advisory Committee

Agenda Item 6(c): Pre-Rule Change Proposal RC_2018_02: K and U parameters in Relevant Level Methodology for 2018 Reserve Capacity Cycle

MAC Meeting 14 February 2018

1. The Proposal

The Relevant Level Methodology, which is defined in Appendix 9 of the Market Rules, is used by AEMO in determining the level of Certified Reserve Capacity for a Facility (usually a Non-Scheduled Generator) under clause 4.11.2(b) of the Market Rules.

Step 17 of Appendix 9 requires AEMO to calculate a Facility Adjustment Factor for each Candidate Facility, which is a function of two parameters, K and U. For the 2015 Reserve Capacity Cycle and onwards, Step 17 of Appendix 9 requires that the values of these parameters must be determined in accordance with clause 4.11.3C.

Clause 4.11.3C requires the Relevant Level Methodology to be reviewed every three years. The last review of the Relevant Level Methodology under clause 4.11.3C was completed in 2014, and included a determination of the K and U values for the 2015, 2016 and 2017 Reserve Capacity Cycles.

In July 2016, the Minister transferred responsibility for the Relevant Level Methodology review to the Economic Regulation Authority (ERA). Under the transitional provisions in clause 1.17.5(d) of the Market Rules, the deadline for completion of the ERA's first review under clause 4.11.3C was deferred from 1 April 2018 to 1 April 2019. This means that the review, which is to determine K and U values for the 2018, 2019 and 2020 Reserve Capacity Cycles, will not be completed in time for the K and U factors to be used for the 2018 Reserve Capacity Cycle.

In this Pre-Rule Change Proposal AEMO seeks to amend the transitional provisions in clause 1.17.5 to:

- allow the K and U values determined for the 2017 Reserve Capacity Cycle to be carried over for the 2018 Reserve Capacity Cycle; and
- change the coverage period of the next review required under clause 4.11.3C to only cover the 2019 and 2020 Reserve Capacity Cycles.

AEMO also seeks to amend Step 17 of Appendix 9 to clarify that it is the ERA (and not AEMO) that determines the K and U factors for future Reserve Capacity Cycles, and that this is done under clause 4.11.3C (and not clause 4.11.3B) of the Market Rules.

2. Recommendation

It is recommended that the MAC discusses AEMO's Pre-Rule Change Proposal.

RCP | Rule Change Panel

Wholesale Electricity Market Rule Change Proposal

Rule Change Proposal ID: *[to be filled in by the RCP]*
Date received: *[to be filled in by the RCP]*

Change requested by:

Name:	Peter Geers
Phone:	+61 7 3347 3059
Email:	Peter.Geers@aemo.com.au
Organisation:	Australian Energy Market Operator
Address:	PO Box 7096, Cloisters Square, Perth, WA, 6850
Date submitted:	*<date submitted to the RCP>*
Urgency:	3-high – Fast Track Rule Change Process
Rule Change Proposal title:	K and U parameters in Relevant Level Methodology for 2018 Reserve Capacity Cycle
Market Rule(s) affected:	1.17.5, Step 17 of Appendix 9

Introduction

Clause 2.5.1 of the Wholesale Electricity Market (WEM) Rules (Market Rules) provides that any person may make a Rule Change Proposal by completing a Rule Change Proposal form that must be submitted to the Rule Change Panel.

This Rule Change Proposal can be sent by:

Email to: rcp.secretariat@rcpwa.com.au

Post to: Rule Change Panel
Attn: Executive Officer
C/o Economic Regulation Authority
PO Box 8469
PERTH BC WA 6849

The Rule Change Panel will assess the proposal and, within 5 Business Days of receiving this Rule Change Proposal form, will notify you whether the Rule Change Proposal will be further progressed.

In order for the proposal to be progressed, all fields below must be completed and the change proposal must explain how it will enable the Market Rules to better contribute to the achievement of the Wholesale Market Objectives.

The objectives of the market are:

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;

(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

Details of the Proposed Rule Change

1. Describe the concern with the existing Market Rules that is to be addressed by the proposed rule change:

Background

Clause 4.10.1(i) of the Wholesale Electricity Market Rules (**Market Rules**) allows a Certified Reserve Capacity applicant to nominate the use of the clause 4.11.2(b) methodology, instead of the clause 4.11.1(a) methodology, in assigning Certified Reserve Capacity[1] to a Scheduled Generator or a Non-Scheduled Generator.

Clause 4.11.2(b) of the Market Rules requires AEMO (unless it rejects the nomination under clause 4.11.2(a) and subject to other exceptions) to assign a quantity of Certified Reserve Capacity to the relevant Facility for the Reserve Capacity Cycle equal to the Relevant Level as determined in accordance with the Relevant Level Methodology in Appendix 9 of the Market Rules.

Step 17 of Appendix 9 of the Market Rules requires AEMO to calculate a Facility Adjustment Factor for each Candidate Facility, which is a function of two parameters, K and U. For the 2015 Reserve Capacity Cycle and onwards, step 17 of Appendix 9 requires that the values of these parameters must be determined in accordance with clause 4.11.3C of the Market Rules.[2]

Clause 4.11.3C of the Market Rules requires the Relevant Level Methodology to be reviewed every three years. The last review of the Relevant Level Methodology under clause 4.11.3C was completed in 2014, and included a determination of the K and U values for the 2015, 2016

[1] This Rule Change Proposal addresses an issue in relation to the 2018 Reserve Capacity Cycle. The reference to Conditional Certified Reserve Capacity in clause 4.10.1(i) (for future Reserve Capacity Cycles) is not presently relevant.

[2] AEMO considers that there are two errors in step 17 of Appendix 9 of the Market Rules. Firstly, the clause reference should be clause 4.11.3C instead of clause 4.11.3B. Secondly, under clause 4.11.3C, the values are determined by the ERA, not AEMO. This Rule Change Proposal includes drafting to correct these errors.

and 2017 Reserve Capacity Cycles.[3] The next review under clause 4.11.3C was due to be completed by 1 April 2018, and must:

1. examine the effectiveness of the Relevant Level Methodology in meeting the Wholesale Market Objectives; and

2. determine the values of the parameters K and U to be applied for the 2018, 2019 and 2020 Reserve Capacity Cycles.

As part of rule changes that commenced in July 2016, responsibility for completing the review of the Relevant Level Methodology was transferred to the Economic Regulation Authority (ERA). At the same time, clause 1.17.5(d) of the Market Rules commenced, which defers the deadline for completion of the ERA's first review of the Relevant Level Methodology under clause 4.11.3C (for the 2018, 2019 and 2020 Reserve Capacity Cycles) from 1 April 2018 to 1 April 2019. The effect of clause 1.17.5(d) is that the K and U values for the 2018 Reserve Capacity Cycle will not be determined, and cannot be applied for the purposes of step 17 of Appendix 9, until the ERA completes its review by 1 April 2019. As a result, Certified Reserve Capacity applicants will effectively be deprived of their right under clause 4.10.1(i) to nominate the use of the clause 4.11.2(b) methodology for the 2018 Reserve Capacity Cycle.

Issue and market impact

AEMO has consulted with the ERA, which has confirmed that it intends to review the Relevant Level Methodology in accordance with the timing in clause 1.17.5(d) of the Market Rules (i.e. by 1 April 2019 and not 1 April 2018). Consequently, AEMO will not have K and U values for the 2018 Reserve Capacity Cycle.

If K and U values for the 2018 Reserve Capacity Cycle are unavailable, AEMO will be unable to use the clause 4.11.2(b) methodology (and the Relevant Level Methodology) to assign a quantity of Certified Reserve Capacity to Facilities. AEMO considers that the lack of transitional provisions for the K and U values for the 2018 Reserve Capacity Cycle is a manifest error in the Market Rules.

AEMO proposes that the transitional provisions in clause 1.17.5 of the Market Rules be amended to:

1. allow the K and U values determined for the 2017 Reserve Capacity Cycle to be carried over for the 2018 Reserve Capacity Cycle; and

2. change the coverage period of the next review required under clause 4.11.3C of the Market Rules to only cover the 2019 and 2020 Reserve Capacity Cycles.

AEMO consulted with members of the Market Advisory Committee and received five supportive responses before developing this Rule Change Proposal.

AEMO does not propose to extend the three-yearly review cycle so that the next review period would cover the 2019, 2020 and 2021 Reserve Capacity Cycles. AEMO considers that this Rule Change Proposal should propose an immediate solution for the 2018 Reserve Capacity Cycle, but otherwise leave the three-yearly review cycle unchanged.

[3] Clause 4.11.3C (in its original 2012 form) required the Independent Market Operator to review the Relevant Level Methodology. Clause 4.11.3C was amended in 2016 and now refers to the ERA.

2. Explain the reason for the degree of urgency:

AEMO proposes that this Rule Change Proposal be progressed via the Fast Track Rule Change Process because it is of a minor or procedural nature and is required to correct a manifest error in the Market Rules.

AEMO notes that Market Participants may submit Certified Reserve Capacity applications for the 2018 Reserve Capacity Cycle between 1 May 2018 and 29 June 2018. AEMO considers it is important that this matter is urgently addressed to provide certainty for Market Participants in advance of the 2018 Reserve Capacity Cycle processes. Further, the rule changes must be in place by 1 July 2018 to ensure that (for applicants who nominate the clause 4.11.2(b) methodology for the 2018 Reserve Capacity Cycle) AEMO can calculate the Relevant Level in time to assign Certified Reserve Capacity by 19 August 2018.

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3. Provide any proposed specific changes to particular Market Rules: *(for clarity, please use the current wording of the rules and place a ~~strikethrough~~ where words are deleted and <u>underline</u> words added)*

Changes to clause 1.17.5

1.17.5 The operation of:

…

(d) clause 4.11.3C is modified so that the Economic Regulation Authority is not required to conduct the first review of the Relevant Level Methodology before 1 April ~~of the second year of the specified period;~~ <u>2019,</u> and

<u>i. the values of the parameters K and U in step 17 of the Relevant Level Methodology to be applied for the 2018 Reserve Capacity Cycle are deemed to be the K and U values determined for the 2017 Reserve Capacity Cycle as published on the Market Web Site; and</u>

<u>ii. in conducting the first review of the Relevant Level Methodology, the Economic Regulation Authority must determine the values of the parameters K and U to be applied for the 2019 and 2020 Reserve Capacity Cycles; and</u>

…

Appendix 9 changes

Step 17: Determine the facility adjustment factor (in MW) for each Candidate Facility f ("Facility Adjustment Factor") in accordance with the following formula:

Facility Adjustment Factor = min (G x Facility Variance (f), Facility Average Performance Level (f) /3 + K x Facility Variance (f))

Where

G = K + U/Facility Average Performance Level (f)

K is determined in accordance with the following table:

Reserve Capacity Cycle	Capacity Year	K value
2012	2014/15	0.001
2013	2015/16	0.002
2014	2016/17	0.003
2015 onwards	From 2017/18 onwards	To be determined by ~~AEMO~~ the Economic Regulation Authority in accordance with clause ~~4.11.3B~~ 4.11.3C.

U is determined in accordance with the following table:

Reserve Capacity Cycle	Capacity Year	U
2012	2014/15	0.211
2013	2015/16	0.422
2014	2016/17	0.635
2015 onwards	From 2017/18 onwards	To be determined by ~~AEMO~~ the Economic Regulation Authority in accordance with clause ~~4.11.3B~~ 4.11.3C.

4. Describe how the proposed rule change would allow the Market Rules to better address the Wholesale Market Objectives:

The proposed amendments address the inconsistency between clauses 4.11.3C and 1.17.5(d), and step 17 of Appendix 9 of the Market Rules with respect to the 2018 Reserve Capacity Cycle, and will ensure that the market functions as intended.

AEMO considers that the proposed amendments will better achieve Wholesale Market Objectives (a) and (d) and are consistent with the remaining objectives.

5. Provide any identifiable costs and benefits of the change:

Costs

The proposed change is not expected to impose any costs on Market Participants or AEMO.

Benefits

The proposed change will ensure that (for applicants who nominate the clause 4.11.2(b) methodology for the 2018 Reserve Capacity Cycle) AEMO can calculate the Relevant Level in time to assign Certified Reserve Capacity by 19 August 2018.

MAC Meeting Agenda Item 6(d)

RCP Rule Change Panel

Update on RC_2014_03: Administrative Improvements to the Outage Process

MAC Meeting
14 February 2018

Overview

- Update on progress since 13 December 2017 MAC meeting
- Summary of current straw man positions
- Next steps

Progress since 13 December 2017

- Seven responses to request for feedback
  - Most respondents generally supportive of proposed approach but some issues raised
- Legal advice confirming MAC issues 17 (late logging of Forced Outages) and 33 (ability to update Forced Outage details) can be addressed in RC_2014_03
- Workshop held 17 January 2018
  - AEMO, Western Power, ERA and Market Participants
  - Workshop slides, handout document and minutes attached to MAC meeting papers
  - Covered most of the feedback issues
  - Follow up meeting with AEMO 6 February 2018

Removal of Consequential Outage authorised notice requirement

- Retain original proposal to remove notice requirement
- Straw man
  - Participant submits Consequential Outage request in SMMITS
  - If AEMO does not approve
    - If Outage has started then AEMO converts to a Forced Outage
    - If Outage has not started then AEMO rejects request

RCP Rule Change Panel
Market Advisory Committee

Logging Forced and Consequential Outages in advance – straw man (1)

- AEMO notifies all affected participants when
  - Triggering outage request submitted
  - Triggering outage request accepted/accepted with conditions/approved/rejected/withdrawn/cancelled/ rescheduled/ends early/ends late
- Participants include reference id (provided by AEMO) when logging ex-ante Consequential Outage requests
- If change to a triggering outage
  - AEMO rejects Consequential Outage requests where appropriate
  - Participant is responsible for amending Consequential Outage end time

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Market Advisory Committee

Logging Forced and Consequential Outages in advance – straw man (2)

- Provisions to cover late notification of changes to triggering outage
  - New limb in Consequential Outage definition
  - Participant responsible for determining outage end time
  - May require submission of additional Consequential Outage request
- Late notification rules – factors taken into account include
  - Reaction time
  - Gate closure time
  - Start-up time
  - Operational state when notified of change

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Market Advisory Committee

Logging Forced and Consequential Outages in advance – straw man (3)

- Reserve Capacity Tests
  - Exemption only for approved Consequential Outage requests
  - Test results discarded if Facility experiences a Consequential Outage during a Reserve Capacity Test
- Other issues
  - Treatment of 'controlled forced' triggering outages
  - When should affected participants have to log Consequential Outage requests in SMMITS?
  - When should participants have to log Forced Outage requests in SMMITS?
  - Inclusion of start-up time in outage periods

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Outage quantity calculation – RCOQ vs Capacity Credits

- Capacity Credits do not always reflect Reserve Capacity Obligations
- RCOQ creates circular definition problem
- Trading Day temperatures unknown on Scheduling Day
- Straw man
  - For ‘7.3.4’ outage schedule assume no special cases (i.e. Capacity Credits)
  - For ‘7.13.1A’ outage schedule use RCOQ assuming no Outages
  - Clarify definitions of Appendix 1(k)(i)(3) and (4)

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Market Advisory Committee

Quantity of de-rating for Scheduled and Non-Scheduled Generators

- Outage quantity reporting as per December 2017 MAC straw man – not required for normal temperature de-rating
- Maximum Sent Out Capacity definition
  - Maximum MW that can be sent out by the Facility on a sustainable basis under normal, optimal conditions
  - Should not exceed the physical limits of network connection
  - Will ‘emergency’ capacity ever need to be dispatched through dispatch system?
- Outage quantities for Scheduled Generators that fail to meet required output levels as per December 2017 straw man
- Materiality threshold for NSG Outages as per December 2017 straw man

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Next steps

- RCP Support to work through implications of late logging of Outages and late changes to Outage details
  - May need some restrictions/monitoring requirements/good faith provisions
- Advice from AEMO on late logging of Forced Outages (action item 31/2017)
- Call for further submissions by start of March 2018
  - Concepts only (not drafting)
  - 2 week submission period
- Draft Rule Change Report – late April 2018

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RCP Rule Change Panel

Workshop for RC_2014_03: Administrative Improvements to the Outage Process

17 January 2018

Session 1 – Consequential Outages

- Main focus on ex-ante Consequential Outages
- General terminology, principles and assumptions
- Linking ex-ante Consequential Outage to triggering outage
- Normal process for ex-ante Consequential Outage
- Changes to triggering outage
- Late notification rules
- Ex-post Consequential Outages
- Consequential Outages and Reserve Capacity Tests
- Next steps

Consequential Outages terminology

- Triggering outage
- Consequential Outage verbs – requested/reported(?), accepted, accepted with conditions, approved, rejected, cancelled, withdrawn, rescheduled
- Ex-ante (requested before commencement) vs ex-post (requested after commencement)

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Ex-ante Consequential Outages – general principles

- Market Participants need timely approval/rejection for ex-ante Consequential Outages
- Changes to triggering outages are unavoidable and need to be accounted for
- Market Participants need prompt notification of changes to triggering outages
- Processes need to be efficient, transparent and auditable

Consequential Outages – working assumptions

- Ex-ante Consequential Outages not used for “maybe” outages
- Participants will be able to amend end time and outage quantity for Forced and Consequential Outages (where appropriate)
- A rescheduled Planned Outage is still the same outage
- Minor delays to start of a (planned) triggering outage ignored unless outage rescheduled and affected participants notified
- AEMO will know (or be advised) which equipment list generators are affected by a planned triggering outage
- Question – do Consequential Outages ever need to extend past the end of the triggering outage?

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Linking ex-ante Consequential Outage to triggering outage

- Straw man for discussion
  - Network Operator decides to request Planned Outage (PO), liaises with affected Market Generators, logs Outage Plan or Opportunistic Maintenance request with AEMO
  - If AEMO accepts/accepts with conditions/approves then AEMO notifies affected Market Generators and provides reference id
  - Affected Market Generator requests PO (normal process) or CO (providing reference id) or mixture of both
  - If CO details are
    - consistent with TO - assign TO status to CO
    - inconsistent with TO - reject

Linking ex-ante Consequential Outage to triggering outage

- Straw man variations
  - Network Operator provides reference id to AEMO and affected Market Generators
  - AEMO provides reference id to Network Operator, Network Operator passes on to affected Market Generators
  - Market Generators can log ex-ante CO before the TO is requested and/or accepted/approved
  - Market Generators can also provide reference id if they request a PO and want to be kept informed of changes to the TO
  - Market Generators are obliged to log an outage of some kind if notified of a TO

Normal process for ex-ante Consequential Outage

- Straw man for discussion
  - AEMO approves any linked COs
    - asap (time limit?) if TO already approved
    - otherwise when AEMO approves the TO
  - AEMO notifies Market Generators with linked COs of TO approval
  - Market Generator can cancel CO and request a PO (subject to normal timeframes)

Normal process for ex-ante Consequential Outage

- Straw man variations
  - AEMO does not notify Market Generators with linked COs when it approves a TO
  - The Network Operator notifies the Market Generators with linked COs when the TO is approved
  - AEMO also notifies any Market Generators with linked POs
  - AEMO notifies all affected Market Generators (regardless of which outages logged/approved)

Changes to triggering outage

- Straw man for discussion
  - Rejection/withdrawal before approval
    - AEMO rejects linked COs and promptly notifies Market Generators (how?)
    - (Assume outage not yet in Balancing Horizon)
  - Cancellation
    - AEMO cancels linked COs and promptly notifies Market Generators
    - Market Generators report any new COs needed under late notification rules and update Balancing Submissions if required

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Changes to triggering outage

- Straw man for discussion (2)
  - Reschedule
    - AEMO reschedules any linked COs to align with the TO unless this conflicts with other outages (in which case ??) and promptly notifies Market Generators
    - Market Generators report any new COs needed under late notification rules and update Balancing Submissions if required
  - Early finish
    - AEMO updates end time of linked COs and promptly notifies Market Generators
    - As for reschedule

Changes to triggering outage

- Straw man for discussion (3)
  - Delayed finish
    - If the TO was a PO, then Network Operator would need a new PO or FO
      - Same reference id or new reference id?
      - Same CO or amendment to existing CO?

Changes to triggering outage

- Straw man variations
  - AEMO only notifies Market Generators, who are responsible for making all changes to their COs
  - Network Operator is responsible for notifying affected Market Generators, who are responsible for updating their COs
  - AEMO is responsible for creating any new COs arising from the late notification rules
  - For early finishes to TOs, AEMO sets the end time of each linked CO taking into account some or all of the late notification rules

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Market Advisory Committee

Late notification rules for changes to triggering outage

- Need to account for
  - Reaction time – how long (e.g. 30 minutes, 60 minutes?)
  - Gate closure time (different for Synergy and IPPs)
  - Start-up times – what needs to be considered?
  - Other factors?
- CO definition – additional limb for late delays/cancellations of a TO
- Who should calculate and review – what information needed?
- New vs amended CO?

Ex-post Consequential Outages

- Straw man for discussion
  - CO reported by Market Generator as soon as practicable – link optional
  - System Management approves or converts to FO
  - Market Generator can update CO or FO once clarity on end time
- Straw man variation
  - AEMO (or Network Operator) may provide reference ids (and expected end times) for major network Forced Outages to affected Market Generators, for use in logging COs

Consequential Outages and Reserve Capacity Tests

- Reserve Capacity Test exemption would only apply to approved COs
- Test results would be discarded if Facility experiences an unexpected CO during a Reserve Capacity Test

Next steps

- Action items?
- Any need for follow up workshop?
- Update at 14 February 2018 MAC meeting
- Call for further submissions asap

Session 2 – Outage quantities, RCOQ and other issues

- Terminology
- Outage quantity reporting - December 2017 MAC meeting straw man
- Forced Outage quantities for Scheduled Generators
- RCOQ and Capacity Adjusted Outage Quantities
- Use of outage quantities in the Market Rules
- Calculation of Outage Rates and Equivalent Planned Outage Hours
- Other issues
- Next steps

Relevant terminology

- Maximum Sent Out Capacity
- Unadjusted Outage Quantity
- Capacity Adjusted Outage Quantity
- 7.3.4 outage quantities

Outage quantity reporting - December 2017 MAC straw man

General Principles

- "Sent Out Capacity" in Standing Data remains temperature-independent – rename Maximum Sent Out Capacity (MSOC)
- Outage quantities for Generators reported as MW de-ratings from Maximum Sent Out Capacity
- Remaining Available Capacity for a Trading Interval = Maximum Sent Out Capacity - ∑Outage quantities
- Generator commitment that Facility will be (or was) capable of providing the Remaining Available Capacity for dispatch over the outage period
- No temperature adjustments required, but temperature expectations may affect the outage quantity recorded

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Outage quantity reporting - December 2017 MAC straw man

- Clarification – outages not required for normal temperature de-rating (will include clarification in Market Rules)
- For discussion
  - Any concerns with temperature-independent outage quantity recording?
  - De-rating against Maximum Sent Out Capacity vs remaining available capacity - pros and cons of each option
  - Maximum Sent Out Capacity definition
    - Maximum Balancing Submission quantity?
    - Ignore contractual (vs physical) DSOC limitations?
    - Emergency output levels?

Forced Outage quantities for Scheduled Generators

- Need clarity on how to determine the outage quantity/ remaining available capacity for a Scheduled Generator that trips off during a Trading Interval or otherwise fails to meet its required output levels
- December 2017 MAC straw man assumes actual average MW output in Trading Interval equals remaining available capacity
- Alternative options? – need to consider
    - Auditability (e.g. for ERA compliance purposes)
    - Available Capacity for Minimum TES calculation
    - Implementation and operational costs
    - Suitability for both Synergy and IPP Facilities

RCOQ and Capacity Adjusted Outage Quantities

- RCOQ requirements for non-intermittent generation systems
  - Reduction if maximum site temperature > 41 degrees
  - May increase for short periods (clause 4.12.4(b)(ii))
  - “must account for staffing and other restrictions” (clause 4.12.4(b)(iii))
  - Reduced by 7.3.4 Planned and Consequential Outage quantities
- Clause 4.12.1(c) (Chapter 7) and ex-ante, non-7.3.4 outages?
- Appendix 1(k)(i)(3) and (4) imply RCOQ relatively static (given clause 2.34.4)

RCQQ and Capacity Adjusted Outage Quantities

- What limit to use in clause 3.21.6 calculations?
  - Capacity Credits do not always reflect obligations
  - RCOQ creates circular definition
  - Trading Day temperatures unknown on Scheduling Day
- Straw man for discussion
  - For 7.3.4 assume no special cases (e.g. use Capacity Credits)
  - For 7.13.1A use RCOQ assuming no outages
  - Clarify definitions of Appendix 1(k)(i)(3) and (4)

RCOQ and Capacity Adjusted Outage Quantities

- Alternative approach (more extensive changes)
    - Remove outage adjustments from RCOQ definition
    - Clarify Scheduling Day assumptions (e.g. maximum site temperature)
    - Amend drafting of 4.12.1 obligations and Net STEM Shortfall accordingly
    - Clarify definitions of Appendix 1(k)(i)(3) and (4)

Use of outage quantities in the Market Rules

- Refer to handout
- Appear to need
  - “7.3.4” Unadjusted Outage Quantities and Capacity Adjusted Outage Quantities by Trading Interval
  - “7.13.1A” Unadjusted Outage Quantities and Capacity Adjusted Outage Quantities by Trading Interval
  - Unadjusted Outage Quantities for public website display
- To support late outage reporting may need updates of 7.13.1A schedules for settlement adjustments

Calculation of Outage Rates and Equivalent Planned Outage Hours

- Move to appendix of the Market Rules
- Make Planned Outage Rate and Forced Outage Rate defined terms
- Equivalent Planned Outage Hours zero if Facility not in Commercial Operation and assigned Capacity Credits
- Planned Outage Rate and Forced Outage Rate are each
  - Zero if no Trading Intervals where in Commercial Operation and assigned Capacity Credits
  - Calculated using only Trading Intervals where Facility in Commercial Operation and assigned Capacity Credits
- Refer to handout

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Other issues

- Legal advice indicates OK to include MAC issues
  - Issue 17 (Bluewaters): ability to log Forced Outages after the 15 day deadline (note AEMO MAC action item)
  - Issue 33 (ERM Power): ensure Forced Outage details can be amended after their initial entry in AEMO's systems
- Materiality threshold for Non-Scheduled Generator outages – use straw man if no further feedback
- Bluewaters vs AEMO Supreme Court decision (Synergy)
- Inclusion of fixes for 30 June 2017 rule change problems?
- Bluewaters' request to remove any requirement to log a Forced Outage for Trading Intervals covered by an approved Commissioning Test

Next steps

- Action items?
  - MAC 31/2017
- Any need for follow up workshop?
- Update at 14 February 2018 MAC meeting
- Call for further submissions asap

Notes for 17 January 2018 workshop for RC_2014_03

Use of Outage quantities in the Market Rules – straw man

Requirement clause(s)	Description	Source	Comments
3.23.1(e), (f) and (h)	Requirements for LoadWatch Report – for each Business Day of a week, the total MW quantity of Outages; the total available generation capacity and total Demand Side Management capacity after accounting for total Outages; and the total available generation capacity and total Demand Side Management capacity after accounting for total Outages and the maximum Operational System Load Estimate.	???	Not sure how these values are being calculated.
4.11.1(h)	Potential for AEMO to reduce the Certified Reserve Capacity assigned to a Facility on the basis of deficiencies in the Facility's Forced Outage rate and/or Planned Outage rate over the previous 36 months.	Proposed new Appendix 12 (moved from PSOP: Facility Outages)	Currently clause 4.11.1(h) states that the Planned Outage rate and the Forced Outage rate for a Facility for a period are calculated in accordance with the PSOP specified in clause 3.21.12. Clause 3.21.12 requires System Management to document to procedure to be followed in determining and reporting Forced Outages and Consequential Outages in the Power System Operation Procedure.
4.12.1(a)(iv) and (b)(iv)	Specification of the Reserve Capacity Obligations of a Market Participant holding Capacity Credits – refers to "capacity expected to experience a Forced Outage at the time that STEM Submissions were due which becomes available in real time"	As this quantity is being compared with RCOQ, 7.3.4 Capacity-Adjusted Outage Quantities (note these will be for Scheduled Generators only)	

Requirement clause(s)	Description	Source	Comments
4.12.6(b) (if retained)	Reduction of the RCOQ for a Facility for a Trading Interval to reflect the amount of capacity unavailable due to a Consequential Outage or Planned Outage included in the schedule maintained by System Management in accordance with clause 7.3.4.	7.3.4 Capacity-Adjusted Outage Quantities for Planned Outages and Consequential Outages	
4.26.1(e)	Capacity refund calculations – calculation of Spare(f,t) for a Scheduled Generator f in the Trading Interval t - uses “the MW quantity of Outage as recorded under clause 7.13.1A(b)”	7.13.1A Capacity-Adjusted Outage Quantities	Need to determine the requirements for updating the schedules that are initially provided within 15 Business Days – depends on how late outage reporting is to be managed.
4.26.1(f)(i)(2)	Capacity refund calculations – calculation of the minimum refund factor RF floor(f,t) – uses “the quantity of Forced Outage for a Facility f in the Trading Interval pt, as recorded in accordance with clause 7.13.1A(b)”	7.13.1A Capacity-Adjusted Outage Quantities	As above
4.26.1A(a)(1)	Facility Reserve Capacity Deficit Refund calculation – uses “the total Forced Outage and Refund Payable Planned Outage in that Trading Interval measured in MW”	7.13.1A Capacity-Adjusted Outage Quantities	As above

Requirement clause(s)	Description	Source	Comments
4.26.2	Net STEM Shortfall calculation – uses MW quantities of Refund Payable Planned Outage; the total MW quantity of Planned Outage associated with Facility f before the STEM Auction for Trading Interval as provided to the AEMO by System Management in accordance with clause 7.3.4; the total MW quantity of Forced Outage associated with Market Participant p before the STEM Auction for Trading Interval t, where this is the sum over all the Market Participant's Registered Facilities of the lesser of the Reserve Capacity Obligation Quantity of the Facility for Trading Interval t and the MW Forced Outage of the Facility for Trading for Trading Interval t as recorded in accordance with Section 7.3; the total MW quantity of Forced Outage associated with Market Participant p in real-time for Trading Interval t, where this is the sum over all the Market Participant's Registered Facilities of the lesser of the Reserve Capacity Obligation Quantity of the Facility for Trading Interval t and the MW Forced Outage of the Facility for Trading Interval t as recorded in accordance with clause 7.13.1A(b).	For the 7.3 references, 7.3.4 Capacity-Adjusted Outage Quantities, and for the other references 7.13.1A Capacity-Adjusted Outage Quantities.	As above
4.26.6(d)	Calculation of the Facility Capacity Rebate for a Scheduled Generator or Demand Side Programme – for a Scheduled Generator, uses "the MW quantity of Outage as recorded under clause 7.13.1A(b)	7.13.1A Capacity-Adjusted Outage Quantities	As above

Requirement clause(s)	Description	Source	Comments
6.3A.2(a)	Information calculated by AEMO on a Scheduling Day and released to each Market Participant by 9:00 AM – Maximum Supply Capability – uses “an allowance for Outages in the schedule maintained in accordance with clause 7.3.4”	7.3.4 Unadjusted Outage Quantities?	Maximum Supply Capability is described in clause 6.3A.2(a) as “the maximum Loss Factor adjusted quantity of energy, in units of MWh, that could be supplied during the Trading Interval based on the Standing Data of that Market Participant’s Scheduled Generators and Non-Scheduled Generators assuming the use of the fuel which maximises the the capacity of each Facility”, less allowances for outages and Ancillary Services. Given this definition, unadjusted outage quantities seem more appropriate than capacity-adjusted outage quantities.
6.3A.2(b)	Information calculated by AEMO on a Scheduling Day and released to each Market Participant by 9:00 AM – Maximum Consumption Capability – uses “an allowance for Outages in the schedule maintained in accordance with clause 7.3.4”	Remove?	Maximum Consumption Capability is described as “the maximum Loss Factor adjusted quantity of energy, in units of MWh, that could be consumed during a Trading Interval by that Market Participant’s Non-Dispatchable Loads, Interruptible Loads and Dispatchable Loads, less an allowance for outages. The only outage quantities likely to be recorded for loads would be for Interruptible Loads (as ancillary service providers), and there seems to be little value in reducing the maximum consumption capability to account for these outages.

Requirement clause(s)	**Description**	**Source**	**Comments**
6.3A.2(c)	Information calculated by AEMO on a Scheduling Day and released to each Market Participant by 9:00 AM – for each Scheduled Generator or Non-Scheduled Generator that is registered as being able to run on Liquid Fuel only, the maximum Loss Factor adjusted quantity of energy, in units of MWh, that could be supplied during the Trading Interval based on the Standing Data of that Scheduled Generator or Non-Scheduled Generator less an allowance for Outages in the schedule maintained in accordance with clause 7.3.4	7.3.4 Unadjusted Outage Quantities?	See above
6.3A.2(d)	Information calculated by AEMO on a Scheduling Day and released to each Market Participant by 9:00 AM – for each Scheduled Generator or Non-Scheduled Generator that is registered as being able to run on both Liquid Fuel and Non-Liquid Fuel, the maximum Loss Factor adjusted quantity of energy, in units of MWh, that could be supplied during the Trading Interval when run on each of Liquid Fuel and Non-Liquid Fuel based on the Standing Data of that Scheduled Generator or Non-Scheduled Generator less an allowance for Outages in the schedule maintained in accordance with clause 7.3.4	7.3.4 Unadjusted Outage Quantities?	See above
6.3A.3(c)	Information calculated by AEMO on a Scheduling Day and released to each Market Participant by 9:05 AM – the total quantity of Planned Outages and Consequential Outages for that Market Participant in the schedule maintained in accordance with clause 7.3.4, in units of MW	7.3.4 Capacity-Adjusted Outage Quantities?	Assume the information provided under clause 6.3A.3 is intended to assist Market Participants to comply with their Reserve Capacity Obligations under clause 4.12.1, and so capacity-adjusted outage quantities are relevant.

Requirement clause(s)	Description	Source	Comments
6.6.2A(b)	Contents of a STEM Submission – Availability Declaration – the Market Participant must declare for each of its Scheduled Generators and Non-Scheduled Generators the maximum Loss Factor adjusted energy available from that Facility based on its Standing Data reduced to account for any energy committed to provide Ancillary Services or which is unavailable due to an outage (where such an outage should only be considered where that outage is reported to the Market Participant by AEMO)	7.3.4 Unadjusted Outage Quantities?	Assume the outage quantities mentioned here are provided to the Market Participant under clause 6.3A.2
6.15.2(a)(ii)	Minimum TES for a Scheduled Generator – refers to "where the Balancing Facility is subject to an Outage, the maximum amount of sent out energy, in MWh, which could have been dispatched given the Available Capacity for that Trading Interval", where Available Capacity is currently defined as "for a Trading Interval, the sent out capacity, in MW, of a Scheduled Generator or Non-Scheduled Generator that was not subject to an Outage notified to AEMO under clause 7.13.1A(b)	Use Maximum Sent Out Capacity less the sum of the 7.13.1A Unadjusted Outage Quantities for the Facility and Trading Interval	This assumes that for a Scheduled Generator that fails to comply with a Dispatch Instruction in a Trading Interval (e.g. trips off or fails to start) the Forced Outage quantity recorded is based on what the Facility actually generated in the relevant Trading Interval. If another approach is used then this would need to be reviewed.

Requirement clause(s)	Description	Source	Comments
6.15.2(c)(ii)	Minimum TES for the Balancing Portfolio – refers to “where a Facility in the Balancing Portfolio is subject to an Outage, the maximum amount of sent out energy, in MWh, which could have been dispatched given the sum of the Available Capacity of Facilities in the Balancing Portfolio for that Trading Interval”, where Available Capacity is currently defined as “for a Trading Interval, the sent out capacity, in MW, of a Scheduled Generator or Non-Scheduled Generator that was not subject to an Outage notified to AEMO under clause 7.13.1A(b)”	The sum of the Maximum Sent Out Capacities less the sum of the 7.13.1A Unadjusted Outage Quantities for the Facilities in the Balancing Portfolio	The use of the (ii) value in the Balancing Portfolio Minimum TES calculation is problematic for various reasons (e.g. the inclusion of Non-Scheduled Generators), but addressing these concerns is not within the scope of this Rule Change Proposal. Note that it is very unlikely that this value would be less than the (i) component of the calculation and therefore actually determine the Minimum TES value for the Balancing Portfolio.
6.15.3(b)	Update of Maximum and Minimum TES values as soon as practicable using the schedule of Outages maintained under clause 7.13.1A(b)	7.13.1A Unadjusted Outage Quantities	Currently TES values cannot be altered after they are updated under 6.15.3(b). AEMO is investigating what is involved in relaxing this restriction to allow for late Forced Outage notifications to flow through to the TES calculations.
7.3.4	System Management must prepare a schedule of Planned Outages, Forced Outages and Consequential Outages for each Registered Facility of which System Management is aware at that time where Outages are calculated in accordance with clause 3.21.6, for each Trading Interval of a Trading Day, between 8:00 AM and 8:30 AM on the Scheduling Day prior to the Trading Day.	Want two schedules produced at this time, for Unadjusted Outages and Capacity-Adjusted Outages	

Requirement clause(s)	**Description**	**Source**	**Comments**
7.10.2(c)	Conditions under which a Market Participant is not required to comply with the most recently issued Dispatch Instruction, Operating Instruction or Dispatch Order applicable to its Registered Facility for the Trading Interval – refers to the "quantity of the Forced Outage or Consequential Outage notified is consistent with the extent to which the Market Participant did not comply with the most recently issued Dispatch Instruction, Operating Instruction or Dispatch Order applicable to its Registered Facility for the Trading Interval"	Unadjusted Outage Quantities	How is this assessed for Facilities that are providing LFAS and/or are in the Balancing Portfolio.
7.13.1A(b)	System Management must record the following data for a Trading Day by noon on the fifteenth Business Day following the day on which the Trading Day ends: the scheduled of all Planned Outages, Forced Outages and Consequential Outages relating to each Trading Interval in the Trading Day by Market Participant and Facility	Two schedules: • Unadjusted Outage Quantities (Scheduled Generators, Non-Scheduled Generators and Intermittent Loads) • Capacity-Adjusted Outage Quantities (Scheduled Generators only)	
7.13.1E(d) and 7.13.1G(d)	Gathering of Outage information for display in near real time on the Market Web Site – "the MW quantity of any de-rating to a Scheduled Generator or Non-Scheduled Generator, as measured on a sent out basis at 15 degrees Celsius"	Unadjusted Outage Quantities (by Outage rather than by Trading Interval), i.e. reductions from Maximum Sent Out Capacity	
Glossary – Available Capacity	"Means, for a Trading Interval, the sent out capacity, in MW, of a Scheduled Generator or Non-Scheduled Generator that was not subject to an Outage notified to AEMO under clause 7.13.1A(b)"	Maximum Sent Out Capacity minus Unadjusted Outage Quantities	See comments for clause 6.15.2(a)(ii)

Requirement clause(s)	Description	Source	Comments
Appendix 9, Step 3(c)	Relevant Level determination – "was affected by a Consequential Outage as notified by System Management to AEMO under clause 7.13.1A"	Included in the schedule of Unadjusted Outage Quantities	Need to consider the effects of any changes to allow late outage reporting
Appendix 9, Step 6(a)	Relevant Level determination – "the schedules of Consequential Outages determined by System Management under clause 7.13.1A"	The scheduled of Unadjusted Outage Quantities	Need to consider the effects of any changes to allow late outage reporting

New Appendix 12: Calculation of Outage Rates

- Propose making Planned Outage Rate and Forced Outage Rate defined terms in the Market Rules (references include 4.11.1(h) and 4.26.1D) and moving their definition to a new Appendix 12 of the Market Rules.
- Propose also including the definition of Equivalent Planned Outage Hours (referenced in clauses 4.26.1D, 4.27.2, 4.27.3, 4.27.3A and the Glossary) in Appendix 12.

Proposed Methodology

(Apologies for the formatting)

AEMO must calculate the Equivalent Planned Outage Hours for a Scheduled Generator or Non-Scheduled Generator f in a Trading Interval t as follows:

If Facility f is not in Commercial Operation or assigned Capacity Credits in Trading Interval t then:

Equivalent Planned Outage Hours(f,t) = zero

Else if Facility f is a Scheduled Generator then

Equivalent Planned Outage Hours(f,t) = (CAPO(f,t) / CC(f,t)) x 0.5

where

CAPO(f,t) is the total Capacity Adjusted Outage Quantity for Planned Outages of Facility f in Trading Interval t

CC(f,t) is the number of Capacity Credits assigned to Facility f for Trading Interval t

Else (Non-Scheduled Generator)

Equivalent Planned Outage Hours (f,t) = (PO(f,t) / MSOC(f,t)) x 0.5

where

PO(f,t) is the total Unadjusted Outage Quantity for Planned Outages of Facility f in Trading Interval t

MSOC(f,t) is the Maximum Sent Out Capacity of Facility f in Trading Interval t

End If

The calculation for Equivalent Forced Outage Hours is the same, except that the calculations use Forced Outage quantities instead of Planned Outage quantities.

AEMO must calculate the Planned Outage Rate for a Scheduled Generator or Non-Scheduled Generator f over a period P as follows:

If there were no Trading Intervals in period P in which Facility f was both assigned Capacity Credits and in Commercial Operation then

Planned Outage Rate (f,P) = zero

Else

Planned Outage Rate (f,P) =

sum(t in T, Equivalent Planned Outage Hours(f,t)) x 100 / (Count_T x 0.5)

where

T is the set of Trading Intervals in period P during which Facility F was both assigned Capacity Credits and in Commercial Operation, and t is a member of that set

Equivalent Planned Outage Hours(f,t) is the Equivalent Planned Outage Hours for Facility f in Trading Interval t

Count_T is the number of Trading Intervals in T

End If

(The calculation for Forced Outage Rate is the same, except that the calculations use Equivalent Forced Outage Hours instead of Equivalent Planned Outage Hours.)

4.12. Setting Reserve Capacity Obligations

4.12.1. The Reserve Capacity Obligations of a Market Participant holding Capacity Credits are as follows:

(a) a Market Participant (other than Synergy) must ensure that for each Trading Interval:

i. the aggregate MW equivalent of the quantity of Capacity Credits held by the Market Participant applicable in that Trading Interval for Interruptible Loads and Demand Side Programmes registered to the Market Participant; plus

ii. the MW quantity calculated by doubling the net MWh quantity of energy to be sent out during the Trading Interval by Facilities registered by that Market Participant; plus

iiA. if a STEM submission does not exist for that Trading Interval, the MW quantity calculated by doubling the total MWh quantity of energy to be consumed by that Market Participant including demand associated with any Interruptible Load, but excluding demand associated with any Dispatchable Load, during that Trading Interval as indicated in the applicable Resource Plan; plus

iii. the MW quantity calculated by doubling the total MWh quantity covered by STEM Offers which were not scheduled and the STEM Bids which were scheduled in the relevant STEM Auction determined by AEMO for that Market Participant under clause 6.9 for that Trading Interval, corrected for loss factor adjustments so as to be a sent out quantity; plus

iv. capacity expected to experience a Forced Outage at the time that STEM submissions were due which becomes available in real time,

is not less than the total Reserve Capacity Obligation Quantity for that Trading Interval for Facilities registered to the Market Participants, less double the total MWh quantity to be provided as Ancillary Services as specified by AEMO for that Market Participant in accordance with clause 6.3A.2(e)(i).

(b) Synergy must ensure that for each Trading Interval:

i. the aggregate MW equivalent of the quantity of Capacity Credits held by Synergy applicable in that Trading Interval for Interruptible Loads and Demand Side Programmes registered to it; plus

ii. the MW quantity calculated by doubling the total MWh quantity which Synergy is selling to other Market Participants as indicated by the applicable Net Contract Position of Synergy, corrected for loss factor adjustments so as to be a sent out quantity; plus

iii. the MW quantity calculated by doubling the total MWh quantity covered by STEM Offers which were not scheduled and the STEM Bids which were scheduled in the relevant STEM Auction determined by AEMO for Synergy clause 6.9 for that Trading Interval, corrected for loss factor adjustments so as to be a sent out quantity; plus

iv. capacity expected to experience a Forced Outage at the time that STEM submissions were due which becomes available in real time,

is not less than the total Reserve Capacity Obligation Quantity for Synergy for that Trading Interval, less double the total MWh quantity to be provided as Ancillary Services as specified by AEMO for Synergy in accordance with clause 6.3A.2(e)(i).

(c) the Market Participant must make the capacity associated with the Capacity Credits provided by a Facility applicable to a Trading Interval, up to the Reserve Capacity Obligation Quantity for the Facility for that Trading Interval, available for dispatch by System Management in accordance with Chapter 7.

4.12.2. A Market Participant holding Capacity Credits must also comply with the following obligations:

(a) the Market Participant must comply with the Outage planning obligations specified in sections 3.18, 3.19, 3.20 and 3.21;

(b) the Market Participant must submit to tests of availability of capacity and inspections conducted in accordance with section 4.25; and

(c) the Market Participant must comply with Reserve Capacity performance monitoring obligations in accordance with section 4.27.

4.12.3. AEMO must use the information described in clauses 4.10.1 and 4.25.12 to set the Reserve Capacity Obligation Quantity to apply to a Facility in each Trading Interval. The Reserve Capacity Obligation Quantity to apply to a Facility may differ between Trading Intervals.

4.12.4. Subject to clause 4.12.5, where AEMO establishes the initial Reserve Capacity Obligation Quantity to apply for a Facility for a Trading Interval:

(a) the Reserve Capacity Obligation Quantity must not exceed the Certified Reserve Capacity held by the Market Participant for the Facility;

(aA) for generation systems that are Intermittent Generators, the Reserve Capacity Obligation Quantity is zero;

(b) for generation systems other than Intermittent Generators, except where otherwise precluded by this clause 4.12.4, the Reserve Capacity Obligation Quantity:

i. must not be less than the amount specified in clause 4.10.1(e)(ii) except on Trading Days when the maximum daily temperature at the site of the generator exceeds 41°C, in which case the Reserve Capacity Obligation Quantity must not be less than the amount specified in clause 4.10.1(e)(ii) adjusted to an ambient temperature of 45°C;

ii. may exceed the amount in clause 4.12.4(b)(i) by an amount up to the amount specified in clause 4.10.1(e)(iii), adjusted to an ambient temperature of 45°C on Trading Days when the maximum daily temperature at the site of the generator exceeds 41°C, for not more than the maximum duration specified in accordance with clause 4.10.1(e)(iii); and

iii. must account for staffing and other restrictions on the ability of the Facility to provide energy upon request; and

(c) for Interruptible Loads, Demand Side Programmes and Dispatchable Loads, except where otherwise precluded by this clause 4.12.4, the Reserve Capacity Obligation Quantity:

i. will equal zero once the capacity has been dispatched under clause 7.6.1C(d) or 7.6.1C(e) for the number of hours per year that are specified under clause 4.10.1(f)(ii);

ii. will equal zero for the remainder of a Trading Day in which the capacity has been dispatched under clause 7.6.1C(d) or 7.6.1C(e) for the number of hours per day that are specified under clause 4.10.1(f)(iii);

iii. [Blank]

iv. must account for staffing and other restrictions on the ability of the Facility to curtail energy upon request; and

v. will equal zero for Trading Intervals which fall outside of the periods specified in clause 4.10.1(f)(vi).

4.12.5. For the first Reserve Capacity Cycle, the initial Reserve Capacity Obligation Quantity for Western Power's generation systems is to equal the Certified Reserve Capacity for Western Power's generation systems, modified such that if the maximum ambient temperature at the site of Western Power's generation systems exceeds 41°C on a Trading Day, as measured by Western Power's SCADA system, then Western Power's Reserve Capacity Obligation Quantity for that Trading Day is to be reduced by the difference between that generation system's rated capacity at 41°C and its rated capacity at 45°C.

4.12.6. Subject to clause 4.12.7, any initial Reserve Capacity Obligation Quantity set in accordance with clauses 4.12.4, 4.12.5, 4.28B.4, or 4.28C.11 is to be reduced once the Reserve Capacity Obligations take effect, as follows:

(a) if the aggregate MW equivalent to the quantity of Capacity Credits (as modified from time to time under the Market Rules) for a Facility is less than the Certified Reserve Capacity for that Facility at any time (for example as a result of the application of clause 4.20.1, clause 4.20.14, clause 4.25.4 or clause 4.25.6), then AEMO must reduce the Reserve Capacity Obligation Quantity to reflect the amount by which the aggregate Capacity Credits fall short of the Certified Reserve Capacity;

(b) during Trading Intervals where there is a Consequential Outage or a Planned Outage in respect of a Facility in the schedule maintained by System Management in accordance with clause 7.3.4, AEMO must reduce the Reserve Capacity Obligation Quantity for that Facility and that Trading Interval, after taking into account adjustments in accordance with clause 4.12.6(a), to reflect the amount of capacity unavailable due to that outage; and

(c) if the generating system, being a generating system referred to in clause 3.21A.2(a), is subject to a Commissioning Test Plan approved by System Management during a Trading Interval, then AEMO must reduce the Reserve Capacity Obligation Quantity for that Facility to zero during that Trading Interval.

4.12.7. If a Facility assigned Certified Reserve Capacity is not a Registered Facility for any time period during which its Reserve Capacity Obligations apply, then the Market Participant which holds the Capacity Credits provided by that Facility will be deemed to have failed to satisfy its Reserve Capacity Obligations during that time period.[1]

[1] See clause 4.26.1 in relation to the refund payable where a Market Participant holding Capacity Credits associated with a Facility fails to comply with its Reserve Capacity Obligations.

RCP | Rule Change Panel
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Minutes

Meeting Title:	RC_2014_03 (Administrative Improvements to the Outage Process) Workshop
Date:	17 January 2018
Time:	10:00 AM – 2:05 PM
Location:	Pods 1 and 2, Albert Facey House 469 Wellington Street, Perth

Attendees	Class	Comment
Jenny Laidlaw	RCP Support	
Sandra Ng Wing Lit	RCP Support	
Jake Flynn	Economic Regulation Authority (ERA)	from 12:35 PM
Matthew Fairclough	Australian Energy Market Operator (AEMO)	
Kang Chew	AEMO	
Chris Wilson	AEMO	
Prem Mahli	AEMO	to 12:05 PM
Nicky Hong	AEMO	to 12:05 PM
Angelina Cox	Synergy	
Wendy Ng	Market Generators (ERM Power)	
Margaret Pyrchla	Western Power	to 12:05 PM
Dean Frost	Western Power	
Ignatius Chin	Bluewaters Power	
Adam Stephen	Bluewaters Power	
Daniel Kurz	Bluewaters Power	
Jacinda Papps	Market Generators (Alinta Energy)	
Sam Lei	Alinta Energy	by phone

Slide	Subject	Action
3	**Consequential Outages terminology** Most attendees agreed the Market Rules should refer to a Market Participant “requesting” rather than “reporting” a Consequential Outage, as the participant was asking for AEMO’s approval for an Outage to be deemed a Consequential Outage.	

4	**Ex-ante Consequential Outages – general principles** No concerns were raised regarding the general principles for ex-ante Consequential Outages listed in Slide 4.	
5	**Consequential Outages – working assumptions** AEMO clarified that a rescheduled Outage was treated by AEMO as a new Outage, except that the linkage to the original Outage was a factor AEMO took into account when prioritising competing Planned Outages under the Market Rules. There was some discussion about when a delay to the start of a triggering outage should require that Outage to be formally delayed/rescheduled, resulting in changes to any associated Consequential Outages. There was general agreement that AEMO should only need to reschedule the triggering outage if the delay was long enough to allow the affected generator(s) to return to service. As this period would depend on the characteristics of the generator(s) involved (e.g. start-up and gate closure times) it was agreed that AEMO should exercise its judgement in these situations, taking the relevant factors into account. Ms Jenny Laidlaw clarified that a Market Generator was not supposed to undertake maintenance while it was on a Consequential Outage. Several attendees agreed on the need to ensure that this obligation is explicit in the Market Rules. Several attendees confirmed that in some (but not all) cases a Consequential Outage might extend past the end of the triggering outage, e.g. where a Facility needed its network connection to be restored before it could commence its start-up.	
6-7	**Linking ex-ante Consequential Outage to triggering outage** The group discussed several options for establishing a link between an ex-ante Consequential Outage request and the triggering outage, including: • whether the Network Operator or AEMO should be responsible for notifying affected participants of a triggering outage; • whether formal notification of affected participants should occur when the triggering outage request is first submitted to AEMO, or when AEMO first accepts/accepts with conditions/approves the triggering outage; • whether Market Participants should be able to request a Consequential Outage before the triggering outage has been accepted/accepted with conditions/approved; and • whether a reference id for the triggering outage should be provided to affected participants, and if so how (and by whom) it should be determined.	

	No final positions were agreed, although there was general agreement that the MPI Id from SMMITS could provide a suitable reference id. Mr Dean Frost considered it would be reasonable and good practice for Western Power to notify affected Market Participants and provide them with the relevant MPI Id when it submitted a Planned Outage request. Mr Frost noted that most network Planned Outages were requested about six weeks in advance and suggested the Network Operator could be required to notify the affected Market Participants within two Business Days of making the request. Mr Frost noted that this option would not however work for Opportunistic Maintenance requests. Most generator attendees indicated that although they were unlikely to request a Consequential Outage before the triggering outage was accepted/accepted with conditions/approved, it was useful to know when the triggering outage request was submitted. AEMO attendees indicated a preference for the Network Operator to be responsible for notifying affected Market Participants. Mr Matthew Fairclough questioned the need for a reference id. It was noted that the entire process (including the handling of exception cases) needed to be considered in order to determine the most efficient approach.	
8-9	**Normal process for ex-ante Consequential Outage** Mr Prem Mahli questioned the value of assigning an accepted or accepted with conditions status to a Consequential Outage, and asked whether instead an ex-ante Consequential Outage request could remain in a Submitted status until the triggering outage was approved or rejected. Mr Mahli agreed that AEMO would need to reject Consequential Outages promptly if they were inconsistent with a valid triggering outage. It was noted that if AEMO approves a Consequential Outage in SMMITS then the relevant Market Participant will be notified automatically (as this is an existing feature of SMMITS). Affected Market Participants with Planned Outage requests (or no outage requests) would not be automatically notified by SMMITS, unless the system was modified to do so. There was some discussion about the net benefits of automatically notifying all affected Market Participants when a triggering outage is approved, rejected, etc.	
10	**Changes to triggering outage – rejection/withdrawal before approval and cancellation before the start of the triggering outage** Rejection before approval: there was general agreement that AEMO should reject any linked Consequential Outages awaiting approval, in which case the relevant Market Participants would be automatically notified by SMMITS. There was also general agreement that this notification should occur as soon as practicable. Cancellation: Mr Matthew Fairclough clarified that if AEMO decides before the start of a triggering outage that the outage cannot	

	proceed, then it will "reject" rather than "cancel" that outage. If a decision is made not to proceed with a triggering outage then AEMO would reject any linked Consequential Outages (and therefore would notify the relevant Market Participants). It was agreed that in some cases the late rejection or withdrawal of a triggering outage could leave a generating unit unavailable for dispatch for some period after the start of its anticipated Consequential Outage. In these situations the Market Generator would need to submit a new Consequential Outage request for the relevant period. It was agreed that the definition of a Consequential Outage will need to be extended to account for these situations.	
11	**Changes to triggering outage – reschedule and early finish** Reschedule: It was agreed that because a rescheduled outage is treated as a new outage (albeit one with special prioritisation), the simplest approach is for AEMO to reject any Consequential Outages linked to the original triggering outage and notify the affected generators. The generators would need to be promptly notified of the details of the new triggering outage; the generators would then submit a Consequential Outage request for the new triggering outage and, if necessary, an additional Consequential Outage request to cover any unavoidable delay in returning to the Balancing Market. It was noted that the timeframes for a reschedule may be much tighter than for a typical Scheduled Outage. Early finish: There was general agreement that AEMO should promptly notify affected Market Participants if a triggering outage is going to end earlier than originally planned, and that the notification should include the revised end time. Market Generators should be responsible for updating their Consequential Outage records to reflect the change to the triggering outage and ensuring they make their Facilities available as soon as possible. There should be no need for a Market Generator to submit an additional Consequential Outage request in these situations. There was some discussion about potential changes to the Market Rules to allow Market Generators to return to the market earlier in these situations. There was also some discussion about how to treat periods at the end of a triggering outage in which a Market Generator can physically reconnect to the network, but Western Power is still performing tests and so the connection is unreliable. There was general agreement that the Market Generator should not return to service unless it is notified by AEMO that the triggering outage is ending early.	
12	**Changes to triggering outage – delayed finish** There was general agreement that: • if the extension of the triggering outage is covered by another Planned Outage then the normal processes would be followed for the new triggering outage; and	

	• if the extension of the triggering outage was a Forced Outage, then Western Power should be responsible for promptly informing AEMO of the extension (including its estimated end time), and AEMO should then be responsible for promptly notifying the affected Market Generators. Market Generators should be responsible for amending their Balancing Submissions as appropriate and submitting a new Consequential Outage request to cover the extension. There was some discussion about the benefits of promptly notifying Market Participants of triggering outage extensions so that they can make themselves unavailable in the Balancing Market, and so prevent the payment of unwarranted constrained off compensation. Ms Laidlaw noted that if the triggering outage extension is a Forced Outage then an MPI Id may not exist when AEMO notifies the affected Market Participants, and the Market Participants may not have time to log the additional Consequential Outage before the Forced Outage begins. Attendees agreed on the need for a general understanding of how the various notification processes would work before determining deadlines for actions, to ensure that they are set as early as practicable but are fair and achievable at a reasonable cost.	
13	**Changes to the triggering outage – straw man variations** There was general agreement that AEMO should reject Consequential Outage requests where appropriate but should not be required to create new Consequential Outage requests or amend the times of existing requests. Instead, AEMO will notify the affected Market Participants, who will be responsible for amending their Consequential Outage records and submitting any new requests that are required.	
14	**Late notification rules for changes to triggering outage** Attendees did not identify any additional factors (apart from reaction time, gate closure time, start-up times and the operational state of the unit at the time of the notification) that should be considered under the late notification rules for Consequential Outages. Mr Chris Wilson noted that these considerations were already covered to some extent in Chapter 7A, in respect of the obligations for Balancing Submissions. There was general agreement that Market Participants should be responsible for determining when they can return to the Balancing Market under the late notification rules, and that it may be helpful for Market Participants to include details of their reasoning in Consequential Outage submissions that relate to late notifications. There was some discussion about the inclusion of start-up times in outage periods for Market Generators. Ms Laidlaw noted that a generating unit returning from a Consequential Outage was not available to the market until it was able to synchronise, but agreed that this needed to be made clear in the Market Rules. ***Ms Laidlaw***	

	proposed to discuss the inclusion of start-up times in outage periods further at the February 2018 MAC meeting.	***RCP Support***
15	**Ex-post Consequential Outages** The AEMO attendees agreed that if AEMO rejected an ex-post Consequential Outage request then it should convert the Outage to a Forced Outage in SMMITS. There was general agreement that it should be possible for participants to amend the end time of a Forced or Consequential Outage (subject to appropriate audit controls). Mr Frost noted that currently all Western Power Forced Outage notifications were dealt with within two weeks of their having occurred, and asked whether any changes were proposed to the requirement to provide full and final details of a Forced Outage within 15 days. Ms Laidlaw noted that while she did not know when the matter would be addressed, there was likely to be value in requiring Market Generators to record at least preliminary details of Forced Outages in SMMITS before the current 15 day deadline, to provide greater transparency and improve the accuracy of Outstanding Amount calculations. It was unclear whether similar benefits would apply to earlier logging of network Forced Outages. Mr Daniel Kurz asked whether the opportunity to convert a Forced Outage to a Consequential Outage would remain (i.e. if a Market Generator, after logging the original Forced Outage, became aware that the outage was actually a Consequential Outage). There was some discussion about the implications of supporting this option and other late changes to outage records. ***Ms Laidlaw proposed to arrange a follow up meeting with AEMO, to discuss the administrative, settlement and prudential implications of changes to Forced and Consequential Outages after their initial lodgement; and the late logging of Forced Outages (i.e. after the 15 day deadline).***	***RCP Support***
16	**Consequential Outages and Reserve Capacity Tests** There was general support from attendees for the proposed approach.	
17	**Consequential Outages - Next steps** ***Ms Laidlaw advised that RCP Support would send out a reminder for any action items identified during the workshop, and would also arrange any follow up meetings that were needed before the 14 February 2018 MAC meeting.*** Mrs Jacinda Papps asked what aspects of the process were likely to be included in the Market Rules versus the Market Procedures. Ms Laidlaw replied that the intention was to leave as much detail as possible to the Market Procedures, but to specify key deadlines and responsibilities for achieving those deadlines (and providing the necessary audit trail) in the Market Rules. Attendees advised that they would need about two weeks to review a call for further submissions, assuming that it covered concepts but did not include drafting. Attendees also agreed that the second	***RCP Support***

	submission period may need to be extended, to allow sufficient time for stakeholders to consider the revised drafting for the Rule Change Proposal.	
	Lunch (12:05 – 12:35 PM)	
20-21	**Outage quantity reporting – December 2017 MAC straw man** No concerns were raised about the proposal to make outage quantity reporting temperature-independent. Attendees agreed that the incremental benefits of the Remaining Available Capacity approach for outage quantity reporting over the straw man approach (de-rating against Maximum Sent Out Capacity) were insufficient to warrant having to implement a new outage system or make far more material changes to SMMITS to implement RC_2014_03, given the high urgency rating of the proposal and the current uncertainties about the scope and timing of future market reforms. There was some discussion about how Maximum Sent Out Capacity should be defined. Ms Laidlaw noted that this Standing Data value would be the MW quantity that a Market Generator needs to cover in its Balancing Submission (even if some of that quantity is usually unavailable); and the maximum available capacity value used by a Market Generator to calculate its outage quantities. ***Ms Laidlaw asked attendees to email RCP Support their views on how Maximum Sent Out Capacity should be defined, and in particular:*** • ***whether it should be limited by the physical limits of the network connection;*** • ***whether it should be limited by the contractual DSOC of the Facility;*** • ***whether it should represent the maximum sustainable capacity under normal, optimal conditions or the maximum output achievable for short periods only under emergency conditions; and*** • ***how and whether any generation capacity normally reserved for embedded loads should be accounted for.***	***All***
22	**Forced Outage quantities for Scheduled Generators** There was some discussion about the straw man methodology to determine the outage quantity for a Scheduled Generator that trips off during a Trading Interval or otherwise fails to meet its required output levels. Some attendees expressed concern that the straw man might over-estimate the outage quantity in some situations, but no practical alternative approaches were offered. ***Ms Laidlaw asked any attendee who wished to propose an alternative methodology to contact her to arrange a meeting.***	***All***
23-25	**RCOQ and Capacity Adjusted Outage Quantities** The group discussed the factors that can affect the RCOQ of a Facility and their implications for the calculation of Capacity	

	Adjusted Outage Quantities, and in particular what quantity (currently specified as "RCOQ") should be used in the clause 3.21.6 calculations. There was general support for adopting the straw man approach rather than an alternative approach that would require changes to the definition of RCOQ and consequential changes such as changes to the Net STEM Shortfall calculation. It was suggested that the Appendix 1(k)(i)(3) and (4) values could be used explicitly in the clause 3.21.6 calculations, provided that their definitions were updated to clarify that the values excluded any adjustments under clauses 4.12.4(b)(ii), 4.12.4(b)(iii) and 4.12.6.	
26	**Use of outage quantities in the Market Rules** ***Ms Laidlaw asked AEMO to email RCP Support details of what outage quantities were/should be used in the preparation of LoadWatch reports under clauses 3.23.1(e), (f) and (h).*** ***Ms Laidlaw asked all attendees to review the "Use of Outage quantities in the Market Rules – straw man" table in the workshop handout document, and email RCP Support if they had questions or concerns about the proposed approach for any of the clauses listed in that table.***	***AEMO*** ***All***
27	**Calculation of Outage Rates and Equivalent Planned Outage Hours** Attendees raised no concerns about the proposal to move the calculation of Outage Rates and Equivalent Planned Outage Hours to an Appendix of the Market Rules. ***Ms Laidlaw asked attendees to review the proposed methodology for calculation of Equivalent Planned Outage Hours, Equivalent Forced Outage Hours, Planned Outage Rate and Forced Outage Rate for Scheduled Generators and Non-Scheduled Generators (provided in the workshop handout) and email RCP Support with details of any questions or concerns.***	***All***
28	**Other issues** Ms Laidlaw noted RCP Support had received legal advice that two candidate issues for the MAC Market Rules Issues List could be addressed as part of RC_2014_03: • Issue 17 (Bluewaters): ability to log Forced Outages after the 15 day deadline; and • Issue 33 (ERM Power): ensure Forced Outage details can be amended after their initial entry in AEMO's systems. Attendees raised no objections to the materiality threshold for reporting of Non-Scheduled Generator Outages proposed at the 13 December 2017 MAC meeting. ***Ms Laidlaw requested that Synergy provide RCP Support with some additional detail on Synergy's suggestion, offered in***	***Synergy***

	previous feedback on RC_2014_03, regarding the implications for RC_2014_03 of the Supreme Court's decision on the recent AEMO vs Bluewaters case. Ms Laidlaw advised that changes to fix problems caused by the amending rules gazetted on 30 June 2017 (relating to the provision of performance modelling data) were outside the scope of RC_2014_03. Mrs Jacinda Papps noted that occasionally events occur (often IT-related) that do not directly involve an Outage of equipment list items but cause an Outage of a Market Participant's Facility. Examples included a recent event where AEMO's AGC system dispatched an Alinta Facility to a lower level than its Dispatch Instruction; and an event involving an extended SCADA outage. There was some discussion about whether these occurrences should be classified as Consequential Outages. Ms Laidlaw advised these events were outside the scope of RC_2014_03. Ms Laidlaw advised that Bluewaters' suggested removal of any requirement to log a Forced Outage for Trading Intervals covered by an approved Commissioning Test was outside the scope of RC_2014_03. Ms Laidlaw suggested that Bluewaters raise its suggestion at the upcoming MAC discussion on Commissioning Test issues.	

The workshop ended at 2:05 PM.

MARKET ADVISORY COMMITTEE MEETING, 14 FEBRUARY 2018

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	19 December 2017	19 February 2018
Market Procedures for discussion	• PSOP: Tolerance Ranges (new) • Monitoring and Reporting Protocol (new)	• PSOP: Communications and Control Systems • IMS Interface • (TBC) PSOP: Facility Outages

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as at 7 February 2018. Changes since the previous MAC meeting are in red text. A procedure change is removed from this report after its commencement has been reported.

ID	Summary of changes	Status	Next steps	Date
AEPC_2017_12: Reserve Capacity Security	The proposed updates aim to improve the process for Market Participants providing Reserve Capacity Security as a Security Deposit, specify the process for AEMO to follow in determining when to Draw Upon Reserve Capacity Security, and generally reduce complexity and improve clarity.	Considered by APCWG 4 Sep 2017. On hold pending consideration of potential rule change.	Publish Procedure Change Proposal	TBA

ID	Summary of changes	Status	Next steps	Date
AEPC_2018_01: Monitoring and Reporting Protocol	The new Monitoring and Reporting Protocol details how AEMO implements its obligations to support the ERA's monitoring of compliance with the Market Rules.	Consultation open	Submissions close	26 Feb 2018
AEPC_2018_02: PSOP: Tolerance Ranges	The new PSOP: Tolerance Ranges documents the procedure for determining and reviewing the Tolerance Range and any Facility Tolerance Range.	Consultation open	Submissions close	7 Mar 2018

Government of Western Australia
Department of Treasury

MAC Meeting Agenda Item 8

Network & Market Reform Program Update

Prepared for Market Advisory Committee

14 February 2018

INDICATIVE TIMEFRAME

Milestone	Timeframe
Industry consultation commencing with release of papers	February 2018
Final report on proposed reforms to improve network access	June 2018
Legislative amendments introduced into Parliament	Late 2018
In-depth industry consultation on network and market arrangements	From mid 2018
Legislative amendments passed by Parliament	2019
Revised network and market arrangements established	2020
2020 Capacity Cycle commences under a new approach	2020
Constrained access ‘go live’ with security-constrained economic dispatch	2022

CABS OFF RANK

Elements	High-level status
Constrained network arrangements	Initiated
Reserve Capacity reforms - capacity allocation with a constrained network	Initiated
Ancillary Services arrangements	Scoping - consultation planned for April onwards
New spot market arrangements	Detailed design - Late 2018 onwards
Short-term Synergy facility bidding and/or dispatch options	Scoping

STAKEHOLDER ENGAGEMENT

- Market Advisory Committee
  - MAC constituted working groups
- WA Electricity Consultative Forum & Generator Forum
- PUO initiated industry forums

RCP Rule Change Panel
Market Advisory Committee

Agenda Item 9: Update on the MAC Market Rules Issues List

14 February 2018

1. Background

During its meeting on 8 November 2017, the Market Advisory Committee (MAC) reviewed 43 issues that had been submitted by members and observers as candidates for inclusion in a MAC Market Rules Issues List.

The MAC identified:

- six issues as potential Rule Change Proposals; and
- seven broader issues, in some cases extending beyond the scope of the Market Rules, that require further review before specific changes to the Market Rules (or other instruments) are progressed.

2. Potential Rule Change Proposals

The six potential Rule Change Proposals were discussed in greater detail at the 13 December 2017 MAC meeting. Following this discussion, RCP Support asked members and observers to provide, for each of the six issues:

- what urgency rating they would recommend for a Rule Change Proposal addressing the issue (i.e. Essential, High, Medium, Low, Housekeeping or Don't Progress); and
- whether their organisation was interested in developing a Rule Change Proposal to address the issue.

Members were also asked to provide the same information for:

- an alternative solution for one of the issues (i.e. the implementation of a full runway model for Spinning Reserve cost allocation to address issue 20/38); and
- issue 17 (Ability to log Forced Outages after 15 day deadline) – although RCP Support proposed to address this issue as part of the Rule Change Proposal RC_2014_03 (Administrative Improvements to the Outage Process), the request was made in case outstanding legal advice indicated that inclusion of the issue in RC_2014_03 was problematic.[1]

RCP Support received six responses to this request. The respondents' urgency rating recommendations are summarised in Table 2.1.

[1] RCP Support has since received legal advice confirming that issue 17 can be addressed as part of RC_2014_03, and so issue 17 will remain on hold in the Market Rules Issues List pending the outcomes of this Rule Change Proposal.

Table 2.1: Recommended urgency ratings for potential Rule Change Proposals

Id	Raised By	Title	Geoff Gaston	Wendy Ng	AEMO	Alinta	Bluewaters	Peter Huxtable
13	AEMO	Use of data for market monitoring and compliance	Medium		Medium	Medium	Medium	Low
14/36	Bluewaters/ ERM Power	Capacity refund arrangements	Low	Happy to park	Don't Progress	Don't Progress	Medium	Don't Progress
18	Bluewaters	Spinning Reserve procurement model	Low		Need to proceed unclear	Don't Progress	Medium	Medium
20/38	Bluewaters/ ERM Power	Spinning Reserve Cost Allocation Model	Low		Full runway method preferred	Don't Progress	High	Don't Progress
31	Synergy	LFAS Report	Medium		Medium	Low	Low	High
43	ERA	SRMC Investigation Process	Medium		Medium	Medium	Low	High
17	Bluewaters	Ability to log Forced Outages after 15 day deadline				Medium		High
20/38 (alt)		Full Runway Spinning Reserve Cost Allocation			High	Medium		Medium

Bluewaters Power (Bluewaters) indicated that it was willing to work with AEMO on the development of a Rule Change Proposal to address issue 18 (Spinning Reserve procurement model) if one is required.

Bluewaters also indicated that it was willing to develop a Rule Change Proposal to implement its proposed solution for issue 20/38 (Spinning Reserve Cost Allocation Model). While Bluewaters considered that a proposal to implement a full runway model could be developed in parallel, it did not offer to participate in the development of that proposal.

No other respondent expressed interest in developing any Rule Change Proposals to address the issues under consideration.

As previously advised, RCP Support intends to obtain a preliminary urgency rating for each issue from the Rule Change Panel at its 22 February 2018 meeting, and then publish the results on the Rule Change Panel's website for the consideration of stakeholders.

3. Requests for Review

As previously indicated, RCP Support plans to schedule a series of preliminary discussions for the seven broader issues, where the MAC will be asked to provide input into:

- confirmation of whether a review is needed to consider the issue; and
- where the requirement for a review is confirmed, identification of the proposed terms of reference, deliverables and relative urgency of that review.

RCP Support proposes to schedule the preliminary discussions at a rate of one per MAC meeting (unless competing priorities prevent this), starting from the 14 March 2018 meeting. A suggested order for scheduling these discussions is presented for consideration by the MAC in Table 3.1.

The issue proposed to be addressed first ('Review of agency roles and responsibilities') was selected on the basis that it is most likely to generate a 'quick win' Rule Change Proposal. The rest of the order is based on RCP Support's preliminary view of the relative importance of the issues and the potential for the MAC to contribute to their resolution. However, RCP Support acknowledges that other orders may be considered to be preferable.

Table 3.1: Suggested order for preliminary discussions of broader review issues

No	Issue
1	Review of agency roles and responsibilities
5	Treatment of storage facilities in the market
6	Behind-the-meter issues
4	Forecast quality
2	Commissioning tests
3	The basis of allocation of Market Fees
7	The Reserve Capacity Mechanism (excluding the pricing mechanism)

4. Recommendation

It is recommended that the MAC:

- note the update on the MAC Market Rules Issues List;
- discuss the urgency ratings for the potential Rule Change Proposals and Rule Participants' willingness to develop the proposals; and
- discuss the suggested order for scheduling preliminary discussions on the broader issues identified by the MAC as requiring further review.