RCP | Rule Change Panel

Market Advisory Committee

Minutes

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	11 February 2020
Time:	9:30 AM – 11:20 AM
Location:	Training Room No. 1, Albert Facey House 469 Wellington Street, Perth

Attendees	Class	Comment
Stephen Eliot	Chair	
Matthew Martin	Minister's Appointee – Small-Use Consumer Representative	
Martin Maticka	Australian Energy Market Operator (**AEMO**)	
Dean Sharafi	System Management	
Sara O'Connor	Economic Regulation Authority (**ERA**) Observer	
Andrew Everett	Synergy	
Shane Duryea	Network Operator	Proxy for Zahra Jabiri
Oscar Carlberg	Market Generators	Proxy for Jacinda Papps
Wendy Ng	Market Generators	
Daniel Kurz	Market Generators	
Patrick Peake	Market Customers	
Geoff Gaston	Market Customers	
Peter Huxtable	Contestable Customers	

Apologies	Class	Comment
Zahra Jabiri	Network Operator	
Jacinda Papps	Market Generators	
Andrew Stevens	Market Generators	
Tim McLeod	Market Customers	

Also in Attendance	From	Comment
Aden Barker	Energy Transformation Implementation Unit (**ETIU**)	Presenter to 11:05 AM

Also in Attendance	From	Comment
Jenny Laidlaw	RCP Support	Minutes
Noel Schubert	ERA	Observer
Elizabeth Walters	ERA	Observer
Kei Sukmadjaja	Western Power	Observer
Ben Bristow	Western Power	Observer
Dimitri Lorenzo	Bluewaters Power	Observer
Jo-Anne Chan	Synergy	Observer
Ben Skinner	Australian Energy Council	Observer
Tom Frood	Bright Energy Investments	Observer
John Lorenti	SynergyRED	Observer
Laura Koziol	RCP Support	Observer
Natalie Robins	RCP Support	Observer
Sandra Ng Wing Lit	RCP Support	Observer
Adnan Hayat	RCP Support	Observer

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30 AM and welcomed members and observers to the 11 February 2020 MAC meeting.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above. The Chair advised that Ms Margaret Pyrchla had resigned her position as Western Power's representative and would be replaced on the MAC by Dr Zahra Jabiri. The Chair thanked Ms Pyrchla for her service to the MAC and wished her the best for her new role in Western Power.	
3	**Minutes of Meeting 2019_11_26** Draft minutes of the MAC meeting held on 26 November 2019 were circulated on 28 January 2020. The MAC accepted the minutes as a true and accurate record of the meeting. **Action: RCP Support to publish the minutes of the 26 November 2019 MAC meeting on the Rule Change Panel's (Panel's) website as final.**	**RCP Support**

Item	Subject	Action
4	**Action Items** The closed action items were taken as read. **Action 27/2019:** Ms Sara O'Connor advised that the ERA had not reached a position on whether it should be assigned responsibility under the Market Rules for setting document retention requirements and confidentiality statuses. **Action 28/2019:** Open. **Action 29/2019:** Open. **Action 30/2019:** Mr Dean Sharafi noted that AEMO had worked with Western Power on this action item. Mr Sharafi confirmed that in a scenario where demand was at a one in ten year peak level, and all network equipment was available for service, all the relevant generators with Capacity Credits, including Yandin, Warradarge, Pinjar, Emu Downs and the other North Country Intermittent Generators could generate to their Capacity Credit level without creating a security issue, but this would require opening the connection between Neerabup Terminal and the 132 kV network. Mr Martin Maticka confirmed that this would increase the Spinning Reserve requirement if all the relevant generators were generating to their Capacity Credit level. There was some discussion about the impact of this increase on the Reserve Capacity Requirement. Action 30/2019 was closed. **Action 31/2019:** The Chair noted that this action item would be discussed under agenda item 8(b). Action 31/2019 was closed.	
5	**MAC Market Rules Issues List (Issues List) Update** The MAC noted the recent updates to the Issues List.	
6	**Update on the Energy Transformation Strategy (ETS)** Mr Aden Barker provided the following updates on the ETS. • Work to refine inputs and run models for the Whole of System Plan (**WOSP**) was currently underway. ETIU was using both a resource planning model and a dispatch model, with some iteration between the two. While the iteration process was expected to continue through to May/June 2020, ETIU expected to give the MAC a presentation on high level outputs in March 2020. • The Energy Transformation Taskforce (**Taskforce**) delivered the Distributed Energy Resources (**DER**) Roadmap to the Minister on 23 December 2019. The DER Roadmap outlines 37 actions to overcome barriers to	

Item	Subject	Action

	increasing DER penetration in the SWIS and improve outcomes and opportunities for customers.
	
	ETIU anticipated that the DER Roadmap would be published in March 2020, subject to Cabinet approval. ETIU would be happy to meet with stakeholders to discuss details of the 37 actions once the DER Roadmap is released.
	
	• ETIU held two Transformation Design and Operation Working Group (**TDOWG**) meetings in December 2019:
	  ○ the first discussed outage management and the high-level parameters for the allocation of Capacity Credits under a constrained network access regime; and
	  ○ the second discussed outstanding matters relating to settlement and Essential System Services (**ESS**) scheduling and dispatch.
	
	• The Taskforce published four information papers in November and December 2019:
	  ○ Revising Frequency Operating Standards in the SWIS;
	  ○ ESS – Scheduling and Dispatch;
	  ○ Market Settlement – Implementation of Five-Minute Settlement, Uplift Payments and ESS Settlement; and
	  ○ Technical Rules Change Management Process).
	
	• The Technical Rules Change Management Process information paper provided further details on matters covered in previous papers, along with draft Access Code changes to implement the new framework for Technical Rules change management. While the draft Access Code changes had been released for consideration, this did not constitute the formal consultation required under the Act.
	
	The Access Code changes were to be packaged with the minor changes associated with the constraint information framework, and some additional content around the timing for Western Power's Access Arrangement 5 (**AA5**) submission to the ERA. The package was expected to be approved by the Minister and released for a formal 30-day consultation period within the next few weeks.
	
	If substantive issues were raised by stakeholders during the consultation period, a decision might be made to not progress all the changes simultaneously, noting the time sensitivity in relation to Western Power's AA5 submission.
	
	• The Taskforce approved changes to the outage management framework on 7 February 2020, and the associated information paper was due to be published in the	

Item	Subject	Action

next two weeks. ETIU indicated that it would meet with stakeholders to discuss any issues relating to this information paper.

- The next Taskforce meeting was scheduled for 28 February 2020 and would consider the framework for market registration and participation, along with operating states and contingency event definitions. The latter included a proposal to provide a clearly articulated reliability standard, and information on how that will work in planning and dispatch. These topics would be covered at the next TDOWG meeting on 12 February 2020.

The following points were discussed:

- Ms Wendy Ng asked whether the Access Code package included changes relating to the proposed governance framework for constraint equations. Mr Barker replied that the package included changes to allow Western Power to recover costs for activities associated with the development of constraint information. The more substantive part of the proposed governance framework would be contained in the Market Rules. The draft Amending Rules were released for public consultation in December 2019 and the consultation period closed on 31 January 2020.

  Mr Barker advised that the draft Amending Rules would be submitted for Taskforce approval during February 2020. Ms Ng reiterated her strong concerns about the proposal to classify limit advice as confidential, questioning how Market Participants would be able to operate efficiently without visibility of the network limits.

  Ms Jenny Laidlaw and Mr Daniel Kurz agreed with Ms Ng that restricting access to limit advice would reduce the effectiveness and value of the proposed framework. Mr Barker noted that stakeholders had consistently expressed this view. Their concerns would be discussed as a specific agenda item at the following week’s meeting of the Program Implementation Coordination Group, and would also be raised with the Taskforce.

- Mr Noel Schubert requested an update on the status of the Minister’s Reserve Capacity pricing reforms. Mr Matthew Martin replied that Energy Policy WA (**EPWA**) submitted a finalised set of draft rules to the Minister on 24 December 2019. The Minister was on leave over the holiday period, and while he had returned from leave the previous week, EPWA was uncertain when he would approve the draft rules due to competing priorities.

Item	Subject	Action
	• Mr Barker noted that on 16 January 2020, EPWA released a directions paper about the creation of a dynamic customer protection framework for behind the meter electricity services. Mr Martin added that EPWA aimed to introduce codes of practice with heads of power in regulations, which would require changes to the Electricity Industry Act 2004. EPWA's first focus would be on generation and storage services that occur behind the meter. The first code working group meeting was scheduled for 12 February 2020 and would be followed by several further meetings. EPWA intended to publish the presentation materials for the working group and was happy to meet with stakeholders on a one-on-one basis throughout the process. Mr Geoff Gaston asked how the new codes of practice would apply to parties with existing exemptions. Mr Martin replied that EPWA still needed to work through this question, and while the changes would not affect all existing exemptions, some transition process may be needed for parties with existing solar power purchase agreement exemptions. Mr Gaston supported the removal of some existing exemptions. • Mr Barker noted that the first behind-the-meter working group meeting was unfortunately scheduled for the same day as the next TDOWG meeting (12 February 2020). While EPWA could not guarantee that in future there would not be several meetings of this type in a single week, EPWA undertook to ensure that the scheduled meeting times did not overlap.	
7	**AEMO Procedure Change Working Group (APCWG) Update** Mr Sharafi noted that the next meeting of the APCWG was scheduled for 20 February 2020. The topics includes revisions to the Balancing Market tie-breaker process that involved changes to the Market Procedure: Balancing Market Forecast and the Market Procedure: Balancing Facility Requirements; and updates to the Market Procedure: Certification of Reserve Capacity. In response to a question from Ms Ng, Mr Maticka advised that AEMO intended to implement the proposed changes to the Market Procedure: Certification of Reserve Capacity in time for their use in the 2020 Reserve Capacity Cycle. The MAC noted the update on AEMO's Market Procedures.	
8(a)	**Overview of Rule Change Proposals** The MAC noted the overview of Rule Change Proposals.	

Item	Subject	Action
	In response to a question from the Chair, MAC members raised no concerns about the new table of expected Panel activities being ordered by reference number.	
8(b)	**North Country Spinning Reserve Issue** Mr Barker advised that following the 26 November 2019 MAC meeting AEMO undertook a preliminary assessment of whether the benefits of increasing the Spinning Reserve requirement to allow the unconstrained operation of Yandin and Warradarge would outweigh the costs, based on analysis used to determine the margin values for the 2020/21 Financial Year. Mr Barker advised that while the work was in no way final or conclusive, it indicated there was likely to be a material benefit in amending the Spinning Reserve standard. In response, ETIU considered the decisions already made by the Taskforce with respect to how the largest credible contingency might be defined, how the Spinning Reserve standard might be calculated and how settlement might then occur in that context; and formed the view that there may be benefit in bringing forward a rule change that implements part of the new market design early. ETIU intended the rule change to include changes to the Spinning Reserve standard to enable multiple generation facilities to form the largest credible contingency, and consequential changes to how settlement quantities are calculated for such facilities, consistent with the causer pays principle. Mr Barker noted that AEMO previously suggested a third change, to remove constrained off payments when a generator is constrained down to reduce the Spinning Reserve requirement. While ETIU would give that change consideration, Mr Barker questioned whether the first two changes and the implementation of the proposed Generator Interim Access (**GIA**) tool arrangements would obviate the need for it. Mr Barker noted that AEMO would be responsible for development of the rule change proposal, which ETIU and the Taskforce would consider before releasing the proposal for formal public consultation. Mr Barker guaranteed a fulsome process of public consultation before the proposal was presented to the Minister for a decision on whether to make the Amending Rules using his rulemaking powers (on the basis that they were consistent with the direction of the new market design). The following points were discussed: • Mr Kurz suggested that the changes were required by 1 July 2020, to ensure the rules were adequate for the next	

Item	Subject	Action
	margin values period to accommodate the larger Spinning Reserve requirement. Mr Barker replied that the changes were needed by the time the Yandin and Warradarge wind farms were commissioned and in operation. However, the consequential settlement changes could have a different implementation timeframe, with an initial indication from AEMO that it may not be able to implement the settlement component until early 2021. Mr Maticka noted that the potential delay related to AEMO's transition to a new settlement system with a different vendor. AEMO proposed an option whereby settlement outcomes for the first few months would be corrected in a subsequent settlement adjustment, to avoid having to implement the changes in a system that was due to be decommissioned. Mr Maticka noted that this approach was unusual, would require more complex drafting and may have some cashflow implications, but would reduce IT implementation costs. • Mr Barker noted that key considerations for ETIU in bringing a change forward from the new market design was whether the benefit was material, what the additional incremental cost was likely to be compared with implementation in October 2022, and whether the early implementation could affect the implementation of the broader market reforms by October 2022. ETIU's initial view was that the incremental cost was outweighed by the benefit. • Mr Kurz noted that the proposed margin values for the 2020/21 Financial Year assumed a higher Spinning Reserve requirement due to the two GIA generators in advance of the rules permitting that requirement. Mr Maticka replied that AEMO's recommendation was based on the current construct of the rules, and the ERA would need to take that into consideration. • Ms Laidlaw asked what would happen if the rule change was not implemented by the time the two generators were in operation. Mr Sharafi replied that System Management would allow for a higher Spinning Reserve requirement to ensure power system security. Mr Barker advised that he was not going to speak for Western Power or AEMO in respect of their views. • Ms Laidlaw asked whether AEMO or ETIU was responsible for the groundwork for changes to the Spinning Reserve standard, noting the concerns raised by AEMO about undertaking this work at the 26 November 2019 MAC meeting. Mr Barker replied that in the first instance, ETIU	

Item	Subject	Action
	was just looking at multiple generators being able to form the largest credible contingency, rather than 70 percent of the largest single generator. The change would apply generally and not be restricted to the contingency involving Yandin, Warradarge and (occasionally) NewGen Neerabup.	
	• Mr Patrick Peake questioned whether, when a new generator connected to a line with existing generation and increased the size of associated contingency, the additional Spinning Reserve costs should be attributed to the new generator or shared among all generators on that line. Mr Maticka replied that his understanding of what had been requested was that the additional costs would be shared among all the generators on the line.	
	Mr Peake suggested that sharing the cost among all the generators was contrary to the causer-pays concept, as the existing generators would not have caused the increase in Spinning Reserve costs. Mr Barker considered that Mr Peake had raised a good question that raised longer-term questions about network planning and how market costs should be taken into account.	
	• Ms Ng noted that NewGen Neerabup was affected by the proposed changes and asked if a ballpark estimate of the additional costs was available. Mr Sharafi replied that complex market modelling would be needed to estimate the additional costs. AEMO had not undertaken any such modelling.	
	Mr Kurz noted that EY's modelling for the recent margin values submission indicated that Yandin and Warradarge would form the largest contingency 21% of the time, and that the costs of constraining the generators (in terms of increased Balancing Prices) were not the same as the costs of allowing them to run and creating a higher Spinning Reserve requirement and higher margin values.	
	Mr Barker agreed that cost estimates would need to be made available as part of the consultation process, and noted that the bar should be as high for the Minister's consideration of rule changes as it was for the Panel's. Mr Kurz considered that the suggested net benefits presented in the EY report needed to be quantified.	
	Ms Laidlaw noted that it seemed likely that the benefits of increasing the Spinning Reserve requirement would outweigh the costs in the specific case of Yandin and Warradarge. However, the cost/benefit outcomes might be quite different for future scenarios with different	

Item	Subject	Action
	configurations, making a cost benefit analysis for a full removal of the standard much more challenging. • Mr Peake noted that the Federal Government was providing funds to Victoria and New South Wales for transmission projects, and asked whether Western Australia intended to seek funding to resolve the North Country issues. Mr Martin replied that there had been some engagement with the Federal Government to seek monetary assistance for various projects. Mr Peake asked whether it would be helpful if the MAC provided a document in support of the Government's requests. Mr Martin replied that the MAC did not have a role in that regard, as it existed to provide advice to the Panel rather than Government. • Mr Sharafi suggested that any additional costs to the market could be used as input to a business case to upgrade the second North Country line to 330 kV. • Mr Barker suggested that the future connection of additional generators on shared lines was likely to be limited for several reasons, including the expected reduction in capacity revenue for co-located facilities. • Mr Barker asked Ms Laidlaw what she meant by the removal of the Spinning Reserve standard. Ms Laidlaw replied that the proposed standard removed any obligation on Western Power to design the network in a way that avoided excessive Spinning Reserve costs. While in future a dynamic tool might find the efficient balance between constraining dispatch and increasing Spinning Reserve, this did not fully resolve the problem. Ms Laidlaw gave an extreme example of moving the two Bluewaters facilities to a single line. While the dynamic tool might determine the most efficient option for any Trading Interval (i.e. constraining the facilities versus enabling additional Spinning Reserve), neither option was likely to be as efficient as connecting the two facilities on separate lines. Ms Laidlaw also noted that despite the proposed cost allocation changes, increasing the Spinning Reserve requirement could increase Spinning Reserve costs for all generators, because the relationship between the Spinning Reserve requirement and Spinning Reserve costs was not always linear. • Mr Barker noted the need to amend the current framework for system planning and indicated that this was likely to be	

Item	Subject	Action
	addressed in a future WOSP. Given the timeframe for building transmission lines, Mr Barker considered the question was what to do in the intra-planning period, both in terms of the operation of the market and managing real constraints in the network. ETIU had supplied part of the answer in the context of the ESS Project around the supplementary mechanism. ETIU intended to release another paper detailing how the supplementary mechanism will operate and the circumstances under which it will be triggered. ETIU also intended to release an information paper on non-co-optimised ESS. This would cover existing services such as System Restart, but also consider options for when a constraint is starting to bind and cannot be resolved through initial network investment, but might be able to be resolved through a Market Participant changing their behaviour or investing in a particular part of the network within a certain timeframe. Mr Barker advised that the intent was to have the Amending Rules made by August 2020. Mr Barker noted that the responsibility was on AEMO in the first instance in terms of the rule change proposal development, and there was also a potential need for additional modelling to quantify the costs and benefits of the change and its early delivery. ETIU aimed to release the proposal for consultation by April-May 2020. The proposal would be progressed via a Taskforce process and the use of the Minister's rulemaking powers, which are specific to the ETS.	
8(c)	**RC_2014_03: Administrative Improvements to the Outage Process – Consequential Outages and Non-Scheduled Generator commitment and decommitment** Ms Laidlaw sought advice from the MAC on the processes used to decommit a Non-Scheduled Generator (**NSG**) before a triggering outage and return the NSG to full operation at the end of the triggering outage. A copy of the discussion slides is available in the meeting papers. Ms Laidlaw presented the following scenario for discussion: • a Market Generator is notified that its NSG (>10 MW) will be unable to generate from 9:00 AM to 5:00 PM on a Trading Day due to a planned triggering outage; and • the triggering outage takes place as scheduled.	

The following points were discussed:

- MAC members confirmed that a Market Generator in this scenario would usually submit zero quantities in its Balancing Submissions for the period between 8:30 AM and 5:00 PM, but would not amend its offer price to cause the NSG to be dispatched off in merit.
- Ms Laidlaw noted previous advice from AEMO that it usually issued a Dispatch Instruction to shut the NSG down before the start of the triggering outage (normally in the preceding Trading Interval but sometimes earlier). Ms Laidlaw suggested that this Dispatch Instruction would be Out of Merit according to the Market Rules, and no MAC members disagreed with this view.
- Mr Sharafi noted that generally both the Market Generator and System Management were able to control the shutdown and ramp rate of the NSG. System Management's preference was that the Market Generator shut down the NSG itself (i.e. without the issue of Dispatch Instructions). AEMO's current practice was to not calculate estimates or constraint payments for the periods in which the NSG was ramping down at the start of the outage or ramping up at the end of the outage.

  Mr Oscar Carlberg noted that a Market Generator required accurate information about a triggering outage to shut down its NSG at the appropriate time and make its Balancing Submissions consistent with the triggering outage. To date Market Generators had not always had enough information to act in this way.
- In response to a question from Ms Laidlaw, Mr Shane Duryea confirmed that requiring Market Generators to manage the return of their NSGs at the end of a triggering outage (i.e. without the use of Dispatch Instructions) would not create a safety risk because Western Power had controls in place to prevent the NSG from starting up before it was safe to do so.
- There was general agreement that an NSG should not receive constrained off compensation for the Trading Interval(s) in which it was shutting down before the start of a triggering outage.
- Ms Laidlaw questioned whether the shutdown of an NSG before the start of a triggering outage could reduce the energy output of the NSG in the relevant Trading Interval(s) by enough to warrant estimating the NSG's output for certification. Mr Carlberg considered that if an NSG was ramping down because of a network outage then it should receive an estimate, because its level of Certified Reserve

Item	Subject	Action
	Capacity should not be affected by a network outage over which it has no control. • Mr Tom Frood suggested that it was easier for System Management to dispatch the NSGs than for the Market Generators to manage the process, and questioned the reasons for System Management's preference. Mr Sharafi acknowledged that in some situations some Market Generators may not have the means to turn their NSGs off. Mr Frood added that not all NSGs were manned on a 24/7 basis. Mr Duryea considered, and most MAC members agreed, that Market Generators needed to be able to turn off their Facilities. Mr Maticka considered there was also an issue about who should have control over an NSG. Mr Maticka understood that there was some obligation on the Market Generator to actually manage the NSG; otherwise it would be acting only as an investor and leaving the management of the NSG to AEMO, which might not produce the most optimal outcomes for the Market Generator. • Mr Sharafi questioned whether not receiving an estimate for a 10-minute ramp down period would have a material impact on a NSG's certification. Mr Carlberg considered that a material risk existed in terms of certification, but reiterated his view that the NSG should not receive constrained off compensation. Ms Laidlaw noted previous advice from AEMO that the shutdown period can span multiple Trading Intervals. • Ms Laidlaw asked whether an NSG should receive constrained off compensation and/or an estimate for certification if, at the end of a triggering outage, System Management returned the NSG to service using Dispatch Instructions that restricted its ramp rate or target MW to limit the LFAS impact. Mr Sharafi replied that in these situations System Management put a constraint on the ramp rate of the NSG. This was not expected to last for a long period of time, because eventually the NSG would reach the same output level, as if its ramp rate had not been constrained. Mr Sharifi considered that while the purist view of the Market Rules may say that the NSG was entitled to constrained off compensation, practically it was a very short period of time and the conditions under which the NSG was constrained are known because of the triggering outage.	

Item	Subject	Action
	Mr Sharafi questioned whether applying the purist view of the rule was warranted. • Ms Laidlaw noted that the current definition of a Consequential Outage did not cover Trading Intervals beyond the end of the triggering outage, as there was no network-related reason to restrict the output of a generator in those Trading Intervals. Ms Laidlaw asked whether in general (i.e. not just at the end of a Consequential Outage) a generator should receive a constraint payment if System Management restricted its output to address a ramp rate issue; and whether the treatment should be different for Scheduled Generators and NSGs. Mr Sharafi noted that the question only applied until the implementation of the new market arrangements. Ms Laidlaw agreed that large scale rule changes may not be warranted before October 2022. Mr Maticka considered that neither Scheduled Generators nor NSGs should receive constrained off compensation in these situations. Mr Kurz considered that these situations did not occur very often for the Bluewaters Facilities; and that he did not see any reason why an NSG should not receive an estimate in these situations. Mr Gaston did not consider that the cost of the changes required to remove constraint payments in these situations would be warranted, given the short timeframes involved. The MAC did not offer any reasons why Scheduled Generators and NSGs should be treated differently in terms of constraint payments. • There was some discussion about the management of triggering outages affecting GIA generators, and how the current practice of using the GIA tool and Operating Instructions to constrain a GIA generator during a triggering outage meant that the output of the generator was not estimated for the purposes of certification. Mr Carlberg noted that Alinta was keen for estimates to be provided when its GIA generators were subject to a triggering outage. Ms Laidlaw noted that the relevant network equipment should be on the Equipment List and asked if there was any reason why the triggering outage processes proposed as part of RC_2014_03 would not work for GIA generators. There was further discussion about why and whether the triggering outage process should be different for GIA generators because of their different contractual relationship with Western Power.	

Item	Subject	Action
	Mr Sharafi and Mr Maticka agreed to take the question on notice. Ms Laidlaw noted that clarity on the issue was urgently needed as it could affect the drafting for RC_2014_03. • Ms Laidlaw sought the views of MAC members on Synergy's suggestion that a Scheduled Generator that suffered a Forced Outage in a Trading Interval should be ineligible for constraint payments in that Trading Interval; and in particular whether they would support the idea if it materially reduced implementation costs for RC_2014_03.	
	Action: AEMO to advise RCP Support and the MAC on whether and why the triggering outage processes recently proposed as part of Rule Change Proposal: Administrative Improvements to the Outage Process (RC_2014_03) should be different for GIA generators.	**AEMO**
	Action: MAC members to email any additional feedback on the questions raised in the discussion of Consequential Outages and NSG commitment and decommitment at the 11 February 2020 MAC meeting to RCP Support by 5:00 PM on Thursday 20 February 2020.	**All**
8(d)	**RC_2017_02: Implementation of 30-Minute Balancing Gate Closure – enhancement of information used in trading decisions** Dr Natalie Robins presented the estimated costs of three options to provide additional Balancing Market information to Market Participants to help improve the accuracy of their trading decisions. A copy of Dr Robins' presentation is available in the meeting papers. Dr Robins sought feedback from MAC members on whether the benefits of the additional information provided under each of the three options would outweigh their estimated implementation costs. The following points were discussed: • Mr Kurz noted that while in general more information led to better decision-making, he needed to give further thought to whether the costs of the options presented were justified by the benefits. Mr Carlberg agreed, noting that Alinta would consider the net benefits of the options given how much time remained before the new market arrangements were to begin. • Ms Ng noted AEMO's concerns about the volume of data that would be created if the Forecast BMO was published	

Item	Subject	Action
	every five minutes, and questioned why this would not also be a problem for the proposed security constrained economic dispatch (**SCED**) systems. Mr Maticka explained that the current systems were only designed to support a 30-minute cycle, and would need to be upgraded to support a more frequent cycle. In contrast, the proposed SCED process will use new systems built on a different technology platform, and will be designed and tuned with a five-minute cycle time in mind. • Mr Sharafi observed that none of the options presented was required to facilitate a shorter Balancing Gate Closure. MAC members requested a week to further consider the net benefit of the options and provide their views to RCP Support. **Action: MAC members to provide their feedback on whether the three options discussed at the 11 February 2020 MAC meeting to provide additional information to Market Participants to help improve the accuracy of their trading decisions would provide sufficient benefit, given the cost estimates provided by AEMO, by 5:00 PM on Wednesday 19 February 2020.**	**All**
8(e)	**RC_2020_02: Adding a Criteria for Acceptance of a Non-Temperature Dependent Load** The Chair noted that Edna May Operations recently raised an issue with RCP Support about the status of its processing plant as a Non-Temperature Dependent Load (**NTDL**). Edna May Operations had provided a Pre-Rule Change Proposal to address their concerns for consideration by the MAC. The Chair asked MAC members for their views on the Pre-Rule Change Proposal, including the urgency rating they would recommend for the proposal. The following points were discussed: • Mr Maticka noted that AEMO had contacted the participant to discuss the issue because the Pre-Rule Change Proposal did not appear to consider that it was fairly easy to reinstate the NTDL status of the Load under the current Market Rules. Mr Maticka also noted that the proposed Amending Rules in the Pre-Rule Change Proposal were based on an old version of the Market Rules. • Mr Carlberg's initial thought was that the rules, as drafted, gave quite a lot of power to the participant to manipulate its NTDL status. Mr Carlberg agreed with Mr Maticka's assessment that the participant could quite easily reapply for NTDL status; and suggested that if this was an isolated	

Item	Subject	Action
	issue affecting a small number of participants then it should not be assigned a very high urgency rating. • Mr Kurz agreed that there already appeared to be enough options in the Market Rules for the participant to manage its NTDL status. • Ms Laidlaw asked MAC members for their views on the proposed additional exemption criterion, leaving aside the question of the urgency of the proposal. The Chair asked members to consider, among other things, whether the drafting opened the way for any gaming opportunities. Mr Carlberg considered that the Load's consumption seemed likely to vary over time, and suggested the participant might be able to manipulate its NTDL status if it knew when those consumption changes were going to occur. Mr Carlberg questioned whether this type of Load should be classified as an NTDL. Mr Gaston questioned whether the NTDL concept was warranted at all, because the Loads were still relying on the market to provide backup even though they had a steady consumption level. Mr Gaston did not consider the issue was very urgent. Mr Peter Huxtable considered that the principle of non-temperature dependence had never been particularly well explained, but was generally supportive of the NTDL concept for Loads with a flat consumption pattern. Mr Huxtable tended to agree with the principle behind the Pre-Rule Change Proposal, but considered there were potential loopholes in the drafting. • Ms Ng considered that, putting aside any drafting issues, the proposal was not urgent but was still worth considering. The MAC generally agreed that the concept behind the Rule Change Proposal was reasonable, but considered further work was needed to address the concerns raised by MAC members. The MAC recommended a Low urgency rating for the Pre-Rule Change Proposal.	
9	**General Business** No general business was discussed.	

The meeting closed at 11:35 AM.