Market Advisory Committee

Agenda

Meeting No.	51
Location:	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Wednesday 11 July 2012
Time:	2.00pm – 5.00pm

Item	Subject	Responsible	Time
1.	**WELCOME**	**Chair**	2 min
2.	**MEETING APOLOGIES / ATTENDANCE**	**Chair**	2 min
3.	**MINUTES FROM MEETING 50**	**Chair**	5 min
4.	**ACTIONS ARISING**	**Chair**	10 min
	a) PRC_2012_02: Analysis of impact on Relevant Demand	**IMO**	15 min
5.	**MARKET RULES**		
	a) Market Rule Change Overview	**IMO**	2 min
	b) Market Rules Evolution Plan update (verbal)	**IMO**	10 min
	c) PRC_2012_06: Clarification of clause 2.10.2A	**IMO**	10 min
	d) PRC_2012_11: Transparency of Outage Information	**IMO**	15 min
	e) PRC_2012_12: Updates to Commissioning Tests	**IMO**	20 min
6.	**MARKET PROCEDURES**		
	a) Overview	**IMO**	5 min
7.	**WORKING GROUPS**		
	a) Overview and membership updates	**IMO**	5 min

Item	Subject	Responsible	Time
	b) RDIWG Update (verbal)	**IMO**	5 min
	c) RCMWG Update (verbal)	**IMO**	10 min
8.	**DEMAND SIDE MANAGEMENT BRIEFING**	**ENERNOC**	15 min
9.	**GENERAL BUSINESS**		
10.	**NEXT MEETING: 6 August 2012 (2.00-5.00pm)**		

Minutes

Meeting No.	50
Location	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date	Wednesday 13 June 2012
Time	2.05pm – 5.30pm

Attendees	Class	Comment
Allan Dawson	Chair	
Andrew Everett	Compulsory – Generator	
Geoff Gaston	Discretionary – Generator	
Ben Tan	Discretionary – Generator	(left at 4.35 pm)
Stephen MacLean	Compulsory – Customer	
Steve Gould	Discretionary – Customer	(left at 4.15 pm)
Michael Zammit	Discretionary – Customer	
Corey Dykstra	Discretionary – Customer	
Peter Huxtable	Discretionary – Contestable Customer Representative	(left at 4.15 pm)
Julian Fairhall	Minister's appointee- Small Consumers' Representative (Proxy)	
Phil Kelloway	Compulsory – System Management	
Neil Gibbney	Compulsory- Network Operator (Proxy)	
Wana Yang	Observer – ERA	
Apologies	**Class**	**Comment**
Peter Mattner	Compulsory – Network Operator	
Shane Cremin	Discretionary – Generator	
Suzanne Frame	Compulsory- IMO	
David Murphy	Minister's appointee- Small Consumers' Representative	
Nerea Ugarte	Minister's appointee- Observer	
Also in attendance	**From**	**Comment**
Debabrata Chattopadhyay	Market Reform	Presenter (left at 3.05 pm)
Will Bargmann	Synergy	Presenter (left at 3.35 pm)
Brendan Clarke	System Management	Presenter
Fiona Edmonds	IMO	Presenter

Aditi Varma	IMO	Minutes
Greg Ruthven	IMO	Observer
Jenny Laidlaw	IMO	Observer
Courtney Roberts	IMO	Observer
Brendan Ring	Market Reform	Observer (left at 3.05 pm)
Wayne Trumble	Griffin Energy	Observer
Jonathan Zuckerman	Power Systems Consultants	Observer (attended from 4.35 pm to 5.30 pm)

Item	Subject	Action
1.	**WELCOME** The Chair opened the meeting at 2.05 pm and welcomed members to the 50th meeting of the Market Advisory Committee (MAC).	
2.	**MEETING APOLOGIES / ATTENDANCE** The following apologies were received: • Shane Cremin (Discretionary Class member) • Peter Mattner (Compulsory Class member) • David Murphy (Minister's appointee) • Nerea Ugarte (Minister's appointee) • Suzanne Frame (IMO) The following other attendees were noted: • Debabrata Chattopadhyay (Presenter) • Will Bargmann (Presenter) • Brendan Clarke (Presenter) • Fiona Edmonds (Presenter) • Aditi Varma (Minutes) • Greg Ruthven (Observer) • Jenny Laidlaw (Observer) • Courtney Roberts (Minutes) • Brendan Ring (Observer) • Wayne Trumble (Observer) • Jonathan Zuckerman (Observer)	
3.	**MINUTES OF PREVIOUS MEETING** The minutes of MAC Meeting No. 48, held on 18 April 2012, were circulated prior to the meeting. Mr Andrew Everett had provided to the Chair the	

	following proposed change: • **Agenda Item 8: General Business (PRC_2012_05)** Mr Everett explain~~s~~ed that this Pre Rule Change Paper proposes to fix an oversight that was made during the drafting of the Amending Rules for the new Balancing and Load Following markets. Mr Everett noted that a previous rule change had resolved the issue of Verve Energy paying for the privilege of providing Ancillary Services when MCAP was negative. Mr Everett noted that the previous rule change had not been carried through to the Amending Rules resulting from RC_2011_10. ~~Mr Everett noted that the Amending Rules resulting from the Rule Change Proposal: Treatment of Negative MCAP on the settlement of Ancillary Services (RC_2009_21) had fixed the issue where MCAP is negative, Verve Energy was paying for the privilege of providing Spinning Reserve.~~ Mr Everett also requested clarification to the sentence in the last paragraph that said referred to the discussion ensued on 'greater value'. The Chair advised Mr Everett that the IMO would listen to the recording again and clarify the sentence. During the meeting no further comments were provided by MAC members and the minutes were agreed to be an accurate reflection of the discussion. *Action Point: The IMO to amend and publish minutes of Meeting No. 48 on the website as final.* Mr Neil Gibbney noted that he had provided some hand-written notes to the Chair to be reflected in the minutes of Meeting no. 47 held on 14 March 2012. *Action Point: The IMO to amend the minutes of Meeting No.47 on the website to reflect Mr Gibbney's recommended amendments.*	
4.	**ACTIONS ARISING** The following updates were noted: • Action item 36 – Mr Greg Ruthven mentioned that this action item would be addressed along with Mr Brendan Clarke's Pre-Rule Change Proposal: Clarification and calculation of Availability Curve (PRC_2012_09). He added that the Availability Curve calculation for this year's Statement of Opportunities (SOO), determined in consultation with System Management and PA Consulting included a load profile that was averaged over the load profiles of last five years. Mr Ruthven also confirmed that an inaugural briefing session for Market Participants was being held on 18 June 2012 on the SOO. • Action item 9– Mr Ruthven noted that analysis had been conducted on Relevant Demand using the proposed approach of aggregating the individual loads proposed in PRC_2012_02 and the current approach of determining the Relevant Demand at the Demand Side Programme level. A paper presenting the results of detailed analysis would be provided in	

	the MAC meeting in July. • Action item 43 – The Chair noted that this was an open action item to be updated by the Public Utilities Office. He added that Mr David Murphy had replaced Dr Paul Biggs and was coming up to speed on this issue. He also noted that he had discussed this issue with Ms Anne Nolan.	
5.	**PRESENTATION: PLANNING CRITERION AND FORECASTING 5 YEAR REVIEW** The Chair invited Mr Ruthven to introduce the presentation. Mr Ruthven noted that the presentation focused on specifically the 5 year review of the Planning Criteria, which was being conducted by Market Reform for the IMO. He noted that there were two main objectives of the presentation: • If a change in methodology was recommended as a result of the review, then the MAC could expect a Rule Change Proposal being submitted later in the year. • The most challenging assumption in the cost-benefit analysis was the cost of unserved energy. The presentation would emphasise this salient point for the consideration of MAC members. Mr Ruthven further added that it is anticipated that a draft report would be published in August and stakeholders would participate in the public consultation process that would include making submissions and a public workshop before the final report is published. Mr Ruthven introduced Mr Dev Chattopadhyay from Market Reform, who proceeded to make the presentation. The following discussion points were noted: • Mr Dykstra queried if the analysis on outages was segregated by facility type i.e., baseload, mid-merit and peaking. Mr Chattopadhyay responded that this information was provided in the report. • Mr MacLean queried if analysis had been undertaken on whether the 10% POE forecast was legitimate in accurately representing a one-in-ten year event. Mr Ruthven answered that the review of forecasting processes which had already commenced was tasked with dealing with this question. Mr Geoff Gaston noted that there was a reserve margin of 60% currently in the market resulting from forecasting error which is a cost that is ultimately paid by consumers. He added that analysis should be done on the load profile and the underlying load forecasting. • There was some discussion among MAC members on actual Forced Outage rates and estimated (base) Forced Outage rates shown in the presentation. It was confirmed that the actual Forced Outage rate was higher (at about 3.5%) than the base rate shown in the presentation. • Mr Dykstra questioned if the analysis should be considered a financial analysis instead of a cost-benefit analysis because there was debate if the administered price used in the analysis truly reflected the economic value of capacity. The Chair mentioned that the analysis was related to the Reserve Capacity Requirement and not the current	

	capacity over-supply situation. Discussion ensued on whether the Reserve Capacity Price used in the analysis included the excess capacity adjustment. Mr Chattopadhyay confirmed that the analysis adjusted for excess capacity. The Chair noted that the Planning Criteria Review and the Forecasting Methodologies Review would be concurrent. He added that separate workshops would be conducted for both but that the recommendations from each review would be considered concurrently by the IMO and the market to ensure that any proposed changes would work appropriately together. He added that the results of these reviews would be used in SOO 2013. *Action Point:* • *The IMO to distribute Market Reform's presentation on the planning criterion review to MAC members*	
5a.	**PRE- RULE CHANGE PROPOSAL: EARLY ENTRY CAPACITY PAYMENTS (PRC_2012_10)** The Chair invited Mr Will Bargmann from Synergy to present the Pre-Rule Change Proposal: Early Entry Capacity Payments (PRC_2012_10). The following discussion points were noted: • Mr Dykstra noted his support for the proposal on its merits. He added that focusing on market outcomes would create a need to treat different types of capacity differently. He added that early capacity payments did not incent generators being available early; instead the penalties associated with not being available early are a more significant incentive. Mr Wayne Trumble concurred that the other incentives in the market such as capacity refunds applying after 1 October will drive a generator to enter the market on time. • Mr Zammit said that the Rule Change Proposal would be more appropriate in the Reserve Capacity Mechanism Working Group (RCMWG) which is dealing with Demand Side Management comprehensively. He added that DSP's should be given a chance to present their own analysis and point of view. He added that if early registration was removed universally, then their organisation might support it. • Discussion ensued between members on differences between generators and DSM. • The Chair noted that when a similar proposal from Alinta to remove the ability of DSM to get early entry capacity payments (PRC_2010_30) was considered by the MAC, the IMO had noted that approving the change would require clearly illustrating that the proposed change would not be discriminatory in nature (Market Objective (c)). The Chair noted that it had sought advice on Alinta's proposed amendments and whether it would be discriminatory from Marchment Hill Consulting. • Discussion ensued on whether there are features of DSM that make them different from generators. The Chair noted that from a technical perspective there might be a difference but that should not	

	translate to treating them different commercially. Mr Bargmann noted that Synergy had sought legal advice on the discriminatory nature of the proposed rule amendment and was happy to share it with the MAC. *Action Point: The IMO to distribute the advice of Marchment Hill Consulting on PRC_2010_30 to MAC members* *Action Point: Synergy to distribute to the MAC its full legal advice on the discriminatory nature of the current early entry capacity payments with respect to DSM.*	
6(a)	**MARKET RULES OVERVIEW** Ms Jenny Laidlaw mentioned that the original issues log had been split into the rule changes issues log (which logs rules that are disjointed) and a suggestion log (which logs suggestions for market enhancements). She added that suggestions for improvement were being organised into a document under the Market Rules Evolution Program and will be prioritised in the IMO's work program. In response to a question from Mr Andrew Everett, she noted that the suggestions would still be in the list and therefore part of a work program.	
6(b)	**RC_2012_08: CONSTRAINED ON AND OFF PAYMENTS FOR NON-SCHEDULED GENERATORS** Ms Laidlaw briefed the MAC on this Rule Change Proposal which was currently out for consultation. MAC members agreed that it was a manifest error that should be progressed using the Fast Track Rule Change Process. In response to a query from Ms Wana Yang it was clarified that a Verve Energy Facility dispatched to provide a Dispatch Support Service would not receive Constrained On Compensation in addition to the payment under its Ancillary Service Contract.	
6(c)	**PRC_2012_09: CLARIFICATION AND CALCULATION OF AVAILABILITY CURVE** Mr Brendan Clarke presented the Pre-Rule Change discussion paper. The following discussion points were noted: • Mr MacLean queried if the 8.2% reserve margin is needed during Trading Intervals when the demand is low. Mr Clarke observed that this question did not directly relate to the calculation of the Availability Curve. • Discussion ensued on whether harmonisation of demand-side and supply-side resources in the RCMWG would have any effect on the calculation of the Availability Curve. • MAC members discussed that there is insufficient clarity on how the curve is calculated. Mr Ruthven noted that the approach presented in the Pre-Rule Change Proposal was to use a capacity duration curve that allows for demand plus a margin. • The Chair noted that the current approach is consistent with the Market Rules as they are written. However, the Rule Change Proposal	

	would add clarity to the rules. • Mr Dykstra suggested that the wording of the proposal could be improved. • MAC members agreed that the proposal should be formally submitted into the Standard Rule Change Process after the wording has been improved. *Action Point: The IMO to work with System Management to improve the clarity of the drafting contained in the proposal for PRC_2012_09 prior to formal submission into the Standard Rule Change Process.*	
7.	**MARKET PROCEDURE CHANGE OVERVIEWS** The Chair invited Ms Fiona Edmonds to present the overview. Ms Edmonds noted the following: • The IMS Interface Market Procedure (PC_2012_04) had been published on the website on 11 June. • The IMO had put forward a number of changes to the IT Market Procedure (PC_2012_05) required for the implementation of the new systems for the Balancing and Load Following markets. The consultation period for PC_2012_05 will close on 9 July. • System Management's PSOPs PPCL0022 – Power System Security and Ancillary Services and PPCL0021 Part A- Commissioning and Testing were also under review and due for approval by the IMO. The Procedure Change Report for PPCL0021 Part B – Dispatch was currently being prepared by System Management prior to formal submission to the IMO for approval. In response to a question from Mr Everett on RC_2011_09: Prudential Requirements, Ms Edmonds noted that the IMO would be extending the first submission period deadline to allow for adequate time to prepare and distribute the associated Market Procedure. Ms Edmonds noted that the IMO was conscious that interested parties should be able to take into account the amended Market Procedure when preparing their submissions on RC_2011_09. The Chair noted that a resignation from the MAC had been received from Mr Dykstra on 7th June. He thanked Mr Dykstra for his association with and contribution to the MAC over the last four years. He added that the IMO was seeking MAC members' approval on appointing Ms Debra Rizzi to the Rules Development Working Group (RDIWG) and Dr Wendy Ng to the Reserve Capacity Mechanism Working Group (RCMWG). He also noted that according to MAC constitution, the IMO would seek nominations for the now vacant position of a Market Customer representative on the MAC and would strive to appoint a new member in time for the July meeting. Mr Dykstra expressed his gratitude for having been part of the MAC and participating in the industry processes.	
8.	**WORKING GROUP OVERVIEW**	

	The MAC noted the Working Group overview. With regard to the RDIWG update, the Chair noted that the IMO was running the first set of scenarios for the new Balancing and Load Following Market. He added that a participant debrief on Parallel Operations week 2 would be held on Friday 22 June. With regard to the RCMWG update, the Chair noted that a set of recommendations on harmonisation of demand-side and supply-side resources will be presented to the RCMWG in its 12 July meeting. He also noted that RCMWG members had been invited to a workshop on 4 July to work through different options to address the oversupply of capacity.	
9.	**CONCEPT PAPER: 2011 OUTAGE PLANNING REVIEW RECOMMENDATIONS – INFORMATION TRANSPARENCY** The Chair invited Ms Edmonds to present the concept paper provided for greater transparency of information relating to the outage planning process. The following comments were noted: • MAC members questioned if the outage information would be available to the public or if it would be limited to Market Participant Interface (MPI). The Chair responded that summary data would be made available through the IMO website and detailed information would be provided on the MPI. • Mr Dykstra that this was a great marginal step forward but what would be of even more interest to industry are any the refinements to the outage planning process. Mr Kelloway noted that the intent was to publish the information to foster the thinking around processes. He further added that System Management would like to address specific issues around Equipment Lists, Opportunistic Maintenance, timelines etc when considering refinements to the outage planning process. The Chair responded that process related issues would be addressed in phase two of the work that would be presented to the MAC in August/September 2012. • Ms Yang observed that the ERA was also interested in improving the outage planning process to achieve better market outcomes. She added that the ERA had suggested a review with regard to the incentives for improving plant availability in the market. She observed that clause 4.27 in the Market Rules which relates to Reserve Capacity Performance Monitoring currently sets the criteria too high to trigger monitoring issues for the IMO. The Chair also noted that Planned Outages need to be more strongly connected with maintenance. The Chair noted that there are provisions in the rules to reconsider future allocation of capacity credits where a facility has not been available for a significant portion of the year. • Discussion ensued on the ability of System Management to call generators back from Planned Outages early. • MAC members agreed that the concept paper should be converted into a rule change proposal. Discussion also ensued around the IT system costs to System Management associated with implementing	

	the proposed changes. *Action Point: The IMO to prepare Rule Change Proposal: Transparency of Outage Information* *Action Point: The IMO to provide to MAC members the list of issues being considered in phase 2 (Outage Planning Process review implementation) and MAC members to provide any additional issues they wish to have included on the list for consideration.*	
10.	**GENERAL BUSINESS** Mr Kelloway queried the Chair about the status of the Confidentiality List. The Chair responded that the IMO had an obligation under the Market Rules to publish a list on the website. He added that the IMO is currently updating the associated Market Procedure which would be presented to the IMO Procedure Working Group.	
CLOSED: The Chair declared the meeting closed at 5:00 pm.		

Agenda item 4: 2012 MAC Action Points

Legend:

Shaded	Shaded action points are actions that have been completed since the last MAC meeting.
Unshaded	Unshaded action points are still being progressed.
Missing	Action items missing in sequence have been completed from previous meetings and subsequently removed from log.

#	Year	Action	Responsibility	Meeting arising	Status/Progress
33	2011	The IMO to consider the suggested amendments to the Pre Rule Change Discussion Paper: Ancillary Services Payment Equations (PRC_2010_27) provided by Mr Stephen MacLean, and update the proposal as appropriate.	IMO	June	Underway. Currently scheduled to go to the September MAC.
36	2011	The IMO to consider updating the load profile used in the Available Curve Calculations for the Statement of Opportunities.	IMO	Dec	Completed. In the most recent 2012 Statement of Opportunities (SOO) the IMO notes that in determining the Availability Curve the IMO first develops a load curve from the average of the annual load curves from the last five years. The shape of this average load curve would be expected to approximate a 50% PoE demand profile and so is then scaled

#	Year	Action	Responsibility	Meeting arising	Status/Progress
					up to match the 50% PoE peak demand and expected energy consumption forecasts for the relevant year. The reserve margin is then added to the load curve to form a capacity requirement curve. The capacity required from more then 24 hour, 48 hour and 72 hours per year is then determined from this curve. For further information refer to Appendix 8 of the 2012 SOO.
43	2011	The Public Utilities Office to provide the MAC with an update on progress around the implementation of incentives for dual fuel facilities in the Wholesale Electricity Market.	PUO	Dec	
7	2012	The IMO to communicate impacts on Prudential Requirements as a result of the introduction of the carbon pricing mechanism for Market Participants prior to 1 July.	IMO	Feb	Completed. The IMO provided a notification to the MAC on 28 June 2012.
9	2012	The IMO to conduct further analysis to assess if there are any material differences on the determination of the Relevant Demand for existing DSP resulting from the different approaches listed in PRC_2012_02 and provide an update to MAC members.	IMO	Mar	Completed. The IMO's analysis is attached as Agenda Item 4a.
10	2012	The IMO and Western Power to consider a revised design for the treatment of NCS facilities which ensures that the costs associated with avoiding a network upgrade via entering into a NCS Contract will accrue to the Network Operator.	IMO/WP	Apr	Underway. The IMO notes that it will work through the issues raised during the 18 April 2012 MAC meeting with Western Power over the upcoming months.
11	2012	System Management to consider whether any process changes for approving network outages could be possible to ensure that Market	SM	Apr	

#	Year	Action	Responsibility	Meeting arising	Status/Progress
		Generators are provided with sufficient notice of the outage.			
14	2012	The IMO to amend and publish minutes of Meeting No. 48 on the website as final.	IMO	Jun	Completed.
15	2012	The IMO to amend the minutes of Meeting No. 47 on the website to reflect Mr Gibbney recommended amendments.	IMO	Jun	Completed.
16	2012	The IMO to distribute Market Reform's presentation on the planning criterion review to MAC members	IMO	Jun	Completed. Circulated to members on 14 June 2012.
17	2012	The IMO to distribute the advice of Marchment Hill Consulting on PRC_2010_30 to MAC members	IMO	Jun	Completed. Circulated to members on 14 June 2012.
18	2012	Synergy to distribute to the MAC its full legal advice on RC_2012-10 relating to the discriminatory nature of the current early entry capacity payments with respect to DSM.	Synergy	Jun	
19	2012	The IMO to work with System Management to improve the clarity of the drafting contained in the proposal for PRC_2012_09 prior to formal submission into the Standard Rule Change Process.	IMO	Jun	Completed. The IMO provided proposed refinements to the drafting through to System Management on 29 July 2012.
20	2012	The IMO to prepare Rule Change Proposal: Transparency of Outage Information	IMO	Jun	Completed. Refer to Agenda Item 5(d)
21	2012	The IMO to provide to MAC members the list of issues being considered in phase 2 (Outage Planning Process review implementation) and MAC members to provide through any additional issues that wish to have included on the list for consideration.	IMO/MAC members	Jun	Completed. The IMO sent a copy of the list to MAC members requesting their feedback on 18 June 2012. The updated list is provided as Appendix 1. A copy of the ERA's comments around the outage process that will be also further considered by the IMO as presented in the 2011 WEM Report

#	Year	Action	Responsibility	Meeting arising	Status/Progress
					for the Minister is provided in Appendix 2.

AGENDA ITEM 4: APPENDIX 1 - LIST OF ISSUES FOR CONSIDERATION AS PART OF THE IMO'S IMPLEMENTATION OF THE RECOMMENDATIONS FROM THE 5 YEAR OUTAGE PLANNING REVIEW

Note: Additional issues added following comment by the MAC and its observers are reflected in red below.

	Recommended by	Issue/Recommendation	Intended outcomes/objective	Phase of work
Information Disclosure				
1	PA Consulting	The IMO, in conjunction with System Management and Market Participants, should develop a change to the Market Rules establishing System Management's obligations with respect to the disclosure of information on Planned Outages. Corresponding protocols within the PSOP: Facility Outages should be made, setting out how the new obligations are to be discharged by System Management. The Market Rules and the protocols should anticipate and encompass the following: • The type of information to be made available; • The frequency with which the information is refreshed; and • The form and mode by which the information is made available. The type of information should include: • The status of the Planned Outage, the equipment affected,	• Publication of information will help generators 'self-sort' their planned outages to preserve the reliability of the electricity system (efficient allocation of resources) • Reduces pressure on System Management to resolve/facilitate conflicts in outage requests • Would improve transparency and confidence in outage planning processes. • Would bring WEM in line with global norms	To be progressed as Phase 1 of the IMO's implementation

	Recommended by	Issue/Recommendation	Intended outcomes/objective	Phase of work
		the time periods affected, the capacity involved and the resultant net operating margin. • Information on historic Forced and Planned outages. • Information on major network outages, including whether any generators are unable to generate due to the outage. The frequency of the information published should be sufficient to inform participants about the extent to which the system can accommodate both longer term and short term opportunistic outages. The form and mode of publication is likely to be web-based, probably using the existing SMITTS system. Information should be readily downloadable, with numerical and graphical representations.		
Reserve Margin				
2	PA Consulting	System Management should consider expanding the PSOP to include how fuel composition might factor into its considerations in the outage approval process	• To improve transparency and confidence	Included into revised PSOP: Facility Outages (PPCL0023). Scheduled to commence on the Balancing Market Commencement Day
Generation and network outage planning and interaction				
3	PA Consulting	System Management should consider changes to clause 3.18.2(c)I to constrain	• Would allow System Management to manage only the	To be considered as part of Phase 2 of the

	Recommended by	Issue/Recommendation	Intended outcomes/objective	Phase of work
		the Equipment List to "all transmission network Registered Facilities that could limit the output of a generating facility or the participation of Demand Side Management during a planned outage."	transmission network equipment that would have an impact on the output of a generating facility during a planned outage (i.e. more efficient allocation of SM resources).	IMO's implementation
4	PA Consulting	Electricity Transfer Access Agreements (ETACs) between Western Power and generators should be reviewed to ensure that they provide a sound basis for the management of the interaction between transmission outage and the transmission services provided by the Network Operator to the Market Participants.	• Network outages should be coordinated with generators • ETACs should play the primary role in managing the interaction between the network operator and affected generators • Should set out the rights and obligations of each party in the event of a Transmission outage which affects Generation	To be considered as part of Phase 2 of the IMO's implementation. Note that this is outside the scope of the IMO's jurisdiction
Outage approval process, timelines and constraints				
5	PA Consulting	System Management should consider amendments to the PSOP and, if necessary, the Market Rules to allow a limited number of advanced-approval outages per Facility per year. These advanced-approval outages would be subject to the normal outage scheduling process.	• Participants have indicated current timelines can be insufficient. • Participants often submit their Resource Plans for a Trading Day without knowing whether their outage request will be approved. • Participants may get left with surplus contracts for outage that doesn't proceed. • Participants may have set in place logistical arrangements for maintenance to proceed only to find their outage plan is turned down.	To be considered as part of Phase 2 of the IMO's implementation.
6	PA Consulting	The IMO should consider amending	• Will improve the interaction of	To be considered as

	Recommended by	Issue/Recommendation	Intended outcomes/objective	Phase of work
		clause 3.19.2(b) to the effect that on-the-day Opportunistic Maintenance may be requested any time on the Trading Day or after 10am on the Scheduling Day.	day-ahead and on-the-day opportunistic maintenance outage timelines. • Improve market participant maintenance planning and certainty.	part of Phase 2 of the IMO's implementation.
7	PA Consulting/System Management	System Management should develop for consideration by the IMO proposed changes to Section 13.5, 14.7 and 15.5 of the PSOP to the effect that the written declaration pertain to the period of the outage, rather than a period prior to the outage commencing. The requirement to provide a written declaration should be mandatory. All such declarations should be published by System Management. Heads of power provided under the Market Rules to allow System Management to require a declaration of a Facility's availability (in MW).	• Time periods requested for in outage applications will align more closely with time periods needed for the outage. • Would allow generators to fix problems properly in the first instance if could apply for opportunistic maintenance and extend the outage, where necessary.	To be considered as part of Phase 2 of the IMO's implementation.
8	PA Consulting	The IMO should propose a rewording of clause 3.19.3A(b) to the effect that Opportunistic Maintenance can be granted over any 24 hour period, irrespective of whether it overlaps Trading Days.	• Would allow maintenance that is opportunistic and short term to span two days (e.g. from 10am to 10am). • Would better achieve the intent of the MR to ensure that requests for Opportunistic Maintenance are in fact opportunistic in nature.	To be considered as part of Phase 2 of the IMO's implementation.
9	Griffin Energy/System	Ability to convert Forced Outages to		To be considered as

	Recommended by	Issue/Recommendation	Intended outcomes/objective	Phase of work
	Management	Planned Outages System Management requests clarification of the principle in clause 3.19.3A which allows System Management to decline an Opportunistic Maintenance request where is consider it has been made principally to avoid capacity refunds. A similar clause is required for Scheduled Outages (it is missing from the Market Rules).		part of Phase 2 of the IMO's implementation
10	System Management	Clarity around approval of Planned Outage extensions. System Management raises the following issues for consideration: • Availability at the commencement of the extension? • When an extension is considerably longer than the initial outage duration which originally involved a small risk of non-return to service?		To be considered as part of Phase 2 of the IMO's implementation.
11	Alinta	Removal of artificial distinction between different categories of Planned Outages and providing System Management with greater flexibility in approving Planned Outages. Specifically, Alinta considers that System Management should be able to consider and approve a 'planned' outage request based solely on an assessment of the proposed outage against the criteria specified in Market Rule (MR) 3.18.11 - provided System Management considered it had sufficient	• Improved efficiency of overall outage approval process. • Removal of Opportunistic Maintenance would simply the outage approval process.	To be considered as part of Phase 2 of the IMO's implementation.

	Recommended by	Issue/Recommendation	Intended outcomes/objective	Phase of work
		time prior to the proposed commencement of the outage to adequately assess the outage request. As part of removing the distinctions between the different 'categories' of 'planned' outages (i.e. moving towards a single definition of a planned outage), the existing limitations inherent in the different outage categories should be removed. For example, restrictions on the duration of an outage, other than when deemed necessary based on an assessment against the criteria in MR 3.18.11, should be removed. Further, and again other than as an outcome of an assessment against the criteria in MR 3.18.11, System Management should not be able to decline a request for an outage simply because a Facility had suffered a Forced Outage. *Note interaction of this recommendation with Issue 6, 7 and 8.*		
12	ERA	The incentives for plant availability created by the inter-relationship between the Reserve Capacity Mechanism and the Reserve Capacity Refund payments should be reviewed by the Reserve Capacity Mechanism Working Group. Specifically, the Working Group should consider whether the design of the Reserve Capacity		To be considered as part of Phase 2 of the IMO's implementation and during the RCMWG's deliberations around the introduction of a dynamic Reserve Capacity Refund

	Recommended by	Issue/Recommendation	Intended outcomes/objective	Phase of work
		Mechanism provides appropriate incentives for plant availability and whether a refund regime that links refund payments to system conditions would improve incentives. *For further details of the issues noted by the ERA in its 2011 Wholesale Electricity Market Report which will be considered during phase 2 of the IMO's implementation please refer to Appendix 2.*		mechanism.
Rule Clarifications				
13	IMO internal	The definition of a Forced Outage should be clarified in the Market Rules to cover anything that either limits • System Managements ability to dispatch the facility; or • The Facilities physical capacity to generate, which is not the result of a Planned Outage or Consequential Outage.	• Improved integrity of the Market Rules and greater clarity over what constitutes a Forced Outage.	To be considered as part of Phase 2 of the IMO's implementation.
14	IMO internal	The ability to be on a partial Forced Outage at the same time as being on a partial Planned Outage needs to be clarified in the Market Rules and PSOP.	• Improved integrity of the Market Rules and better understanding of how the processes apply for partial outages	To be considered as part of Phase 2 of the IMO's implementation.

	Recommended by	Issue/Recommendation	Intended outcomes/objective	Phase of work
15	IMO internal	Clause 3.21.4 requires that Forced Outages and Consequential Outages must be logged by the Participant where applicable for facilities • "on the list described in clause 3.18.2" the Equipment List • "to which clause 3.18.2A relates" - generators or Intermittent Loads under 10MW nameplate capacity. However, clauses 3.21.1 and 3.21.2 define Forced/Consequential Outages as outages to facilities on the list described in clause 3.18.2. The IMO to consider expanding the definitions of Forced/Consequential Outage to include both sets of facilities that are required to log them.	• Improved integrity of the Market Rules	To be considered as part of Phase 2 of the IMO's implementation.
16	IMO internal	The definition of a Planned Outage should be clarified in the Market Rules to make it clear that these can include both full and partial outages	• Improved integrity of the Market Rules	To be considered as part of Phase 2 of the IMO's implementation.
17	IMO internal	As Planned Outages by Facility are now public information (under the Amending Rules resulting from RC_2011_10 which will remove the SWIS Restricted Confidentiality Class), clause 3.18.5D may be redundant.	• Improved integrity of the Market Rules	To be considered as part of Phase 2 of the IMO's implementation.
18	IMO internal	There is some circularity between clauses 3.18.4 and 3.19.1. Clause 3.18.4 requires System Management to "maintain an outage schedule, containing information	• Improved integrity of the Market Rules	To be considered as part of Phase 2 of the IMO's implementation.

	Recommended by	Issue/Recommendation	Intended outcomes/objective	Phase of work
		on all Scheduled Outage". Clause 3.19.1 defined Scheduled Outage as meaning outage in the outage schedule. This circularity could be addressed by amending clause 3.18.4 to "… containing information on all ~~Scheduled Outages~~ Outage Plans approved by System Management (including as a result of any direction by the IMO under clause 3.18.15(f))".		
19	Griffin Energy	Greater clarification of outage approval process. *Note that this will be provided through consideration of the issues relating to the outage approval timelines and constraints noted above and the other recommended clarifications to the process.*	• Improved integrity of the Market Rules and PSOPs	To be considered as part of Phase 2 of the IMO's implementation
20	IMO internal	There are a number of other minor and typographical changes to clauses relating to the outage planning process that have been identified by the IMO.	• Improved integrity of the Market Rules	To be considered as part of Phase 2 of the IMO's implementation.
21	Alinta	Consider whether clause 3.19.12 achieves its intended purpose of compensating Market Participants where any outage logged more than 12 months in advance is cancelled in the 48 hours leading up to the start of the outage. Alinta considers the 48 hour rule should be amended to allow the Market Participant to specify the minimum required notice period (restricted to a	• Ensure adequate compensation for cancelled outages is provided	To be considered as part of Phase 2 of the IMO's implementation.

	Recommended by	Issue/Recommendation	Intended outcomes/objective	Phase of work
		maximum duration – i.e. 30 days).		

Summary of the Outage Planning Process section of the ERA's 2011 WEM Report to the Minister for Energy

In its 2011 Report to the Minister for Energy on the effectiveness of the Wholesale Electricity Market (WEM), published on 14 May 2012, the Economic Regulation Authority (ERA) discussed three aspects of the outage planning process, being: price spikes during Planned Outages; rates of Planned Outages; and the granting of Planned Outages. A summary of the ERA's views and concern from that report are listed below.

- The ERA considers that it is appropriate to have System Management base its decisions [on whether to approve Market Participant's requested Planned Outages] on system security alone, and not on price (Section 2.4.2, p. 22).

- The ERA is concerned that current rates of Planned Outages by some generation facilities in the WEM appear excessive. The ERA notes that the Planned Outage rates for some facilities in the WEM are extremely high and, in many cases, significantly higher than in previous Reserve Capacity Years. The ERA noted some higher Planned Outage rates, in particular at Verve Energy's facilities. (Section 2.4.3, p. 22) The ERA is concerned that these Planned Outage rates may be having a negative effect on outcomes in the WEM, particularly price outcomes in the Short Term Energy Market (STEM) and Balancing Process. (Section 2.4.3, p. 23).

- The ERA notes that there is a provision for monitoring Planned Outages under the Reserve Capacity Mechanism (RCM). As part of the Reserve Capacity Performance Monitoring requirements, the Independent Market Operator (IMO) must require Market Participants with a facility that has been unavailable due to Planned Outages for more than 1,000 hours (equivalent to 42 days or 12 per cent of a year) during the preceding 12 calendar months, to provide a report explaining these Planned Outages and setting out the expected maximum number of Planned Outages for the facility in the next 24 months. However, the ERA notes that these provisions are only triggered in circumstances in which SWIS-wide available capacity drops below a certain threshold level (i.e., 80 per cent during Hot Season and 70 per cent in either the Intermediate Season or Cold Season) for at least 40 days in any 12 month period. To date, there have been instances where the system availability threshold has been reached, however, the number of days were not as high as 40 over a 12 month period. Thus, the requirement for Market Participants with excessive Planned Outages to provide an explanatory report has not been triggered i.e., despite the poor availability of specific facilities. The ERA considers that the threshold for the IMO's monitoring of individual facility's availability level could be set too high and that this issue should be examined more fully.

- In the WEM, the incentive to be available to generate is driven both by potential energy market revenues (through the STEM or Balancing) and revenues through the RCM. The RCM is relevant because the total revenues that generators receive for their capacity will depend on whether they are required to make Reserve Capacity Refund payments as a result of plant unavailability. For these reasons, the ERA considers that determining whether Market Participants have appropriate incentives to make their generation plant available depends on the incentives for availability that are driven by the RCM. (Section 2.4.3, p. 23).

The ERA made the following recommendation to the Minister in its Report on the Outage Planning Process (p. 24):

> The incentives for plant availability created by the inter-relationship between the Reserve Capacity Mechanism and Reserve Capacity Refund payments should be reviewed by the Reserve Capacity Mechanism Working Group.
>
> Specifically, the working group should consider whether the design of the Reserve Capacity Mechanism provides appropriate incentives for plant availability and whether a refund regime that links refund payments to system conditions would improve incentives for availability.

The ERA's 2011 Wholesale Electricity Market Report to the Minister for Energy is published on the ERA's website and is available for download at the following link: http://www.erawa.com.au/cproot/10372/2/20120514 2011 Annual WEM Report for the Minister for Energy - Public Version.

Agenda Item 4a: Analysis of impact on Relevant Demand of PRC_2012_02 (Action Item 9 (2012))

EnerNOC presented a Pre-Rule Change Proposal PRC_2012_02, entitled "*Relevant Demand for a Demand Side Programme*", at the 14 March 2012 MAC Meeting. EnerNOC's proposal seeks to amend the methodology for the determination of the Relevant Demand (RD), which is a measure of the "baseline" consumption of a Demand Side Programme (DSP).

The current RD methodology is calculated as the median of the total consumption of all loads within a DSP for a set of 32 Trading Intervals from the previous Hot Season. The proposed methodology would calculate the median consumption for each NMI individually, with the RD for the DSP being the sum of the median consumption values for all loads within the DSP. The proposed methodology may result in a different RD value for a DSP with two or more associated loads, but would have no impact for a DSP with one associated load.

A copy of EnerNOC's proposal is provided as Appendix 1.

The MAC asked the IMO to conduct further analysis to assess if any material changes in RD would result from the proposed methodology change.

Analysis of impacts

As of May 2012, eight DSP's were in operation with more than one associated load. The IMO has calculated the RD value for these DSP's that would result from the proposed methodology change (Approach A) and compared these results with the existing methodology (Approach B). These results are summarised below:

- 4 DSP's would have a higher RD and 4 would have a lower RD under the proposed methodology.
- The 8 DSP's have a total of 195 associated loads. The proposed methodology would result in a higher contribution to RD from 115 (59%) of those loads, a lower contribution from 76 (39%) loads and no change from 4 (2%) loads.
- The sum of the RD's for the 8 DSP's would increase from 223.8 MW (existing methodology) to 233.6 MW (proposed methodology), an increase of 4.4%.

As noted in EnerNOC's proposal, there is the potential for the proposed methodology to move RD in either direction for DSP's that have more than one associated load. While the IMO considers that the results presented above are based on a small sample size, the results represent an additional RD for DSP's of 9.8 MW.

Wholesale Electricity Market
Rule Change Proposal Form

Change Proposal No: *[to be filled in by the IMO]*
Received date: *[to be filled in by the IMO]*

Change requested by:

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Address:	45 Ventnor Avenue, West Perth
Date submitted:	*2 February 2012*
Urgency:	*3-High*
Change Proposal title:	Relevant Demand of a Demand Side Programme
Market Rule(s) affected:	4.26.2CA

Introduction

Market Rule 2.5.1 of the Wholesale Electricity Market Rules provides that any person (including the IMO) may make a Rule Change Proposal by completing a Rule Change Proposal Form that must be submitted to the Independent Market Operator.

This Change Proposal can be posted, faxed or emailed to:

Independent Market Operator
Attn: Manager Market Development and System Capacity
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax: (08) 9254 4339
Email: market.development@imowa.com.au

The Independent Market Operator 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 electricity 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 Market Rule Change

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

Context

The development of the Relevant Demand methodology for a Demand Side Programme (DSP) was considered as part of an extensive set of rule changes (RC_2010_29) to enable a "portfolio management" approach for DSPs. The idea of the new method was that the performance of a DSP would be assessed in aggregate, rather than on a site-by-site basis, as was the case prior to the implementation of the RC_2010_29 changes.

As part of the development of the DSP Relevant Demand methodology, Data Analysis Australia (DAA) was commissioned to consider the method for calculating the Relevant Demand (RD) of DSPs[1]. As set forth in their paper, a key requirement of the analysis was to formulate a methodology that was both "stable and reliable".[2]

DAA investigated two ways of combining data from the constituent loads to produce a portfolio RD. In each case, the RD is calculated by taking a median across the specified peak trading intervals. The difference is that:

- In Approach A, an RD is calculated for each NMI in turn, then the results are summed to give the portfolio RD.
- In Approach B, the loads are summed first, then the RD is calculated from these summed values.

DAA's analysis showed that "there does not appear to be an obvious bias between the approaches whereby one approach yields consistently higher Relevant Demands over the other"[3].

Further, their results "demonstrated that the order by which the aggregation occurs has little effect on the stability and reliability of the relevant demand"[4].

In RC_2010_29, it was decided to use Approach B as it appeared easier to administer:

> "Following the outcomes of DAA's analysis which found no significant difference between the two options, the IMO did not consider it is necessary to calculate the RD level for each individual Load as this would create unnecessary operational overhead and not improve the RD levels ability to reflect the normal operational level of the DSP during required intervals."[5]

It is understood, however, that the operational impact in utilising the alternative Approach A is minor, and existing tools designed to calculate DSP RDs could accommodate the change relatively simply.

[1] Comparison of Alternative Relevant Demand Calculation Methodologies, Data Analysis Australia, Project: IMO/3, July 2010.
[2] Ibid, Section 1, page 1.
[3] Ibid, Section 9, page 36.
[4] Ibid, Executive Summary, page v.
[5] RC_2010_29 Final Rule Change Report, Appendix 1, page 101 (of PDF)

Comparison: Approach A vs. Approach B

EnerNOC supports DAA's finding that neither approach has an obvious bias.

Either method can give the higher result, depending on the data. We demonstrate this with some extreme examples.[6]

In Figure 1, the DSP's RD using Approach B is 1.2MW, whereas using Approach A, gives a result of 0.3MW – a difference of 0.9MW.

Figure 2 illustrates two slightly different loads. In this case, the DSP's RD using Approach A yields a RD result of 2.1MW, whereas Approach B yields a RD of 1.2MW; the same 0.9MW difference, but in the opposite direction.

Although this is a simplistic example, it clearly shows that either approach can yield a higher RD. When analysing different portfolios that exhibit similar characteristics this same principle would stand true.

Figure 1: Comparison of DSP Relevant Demand Approaches (A & B)

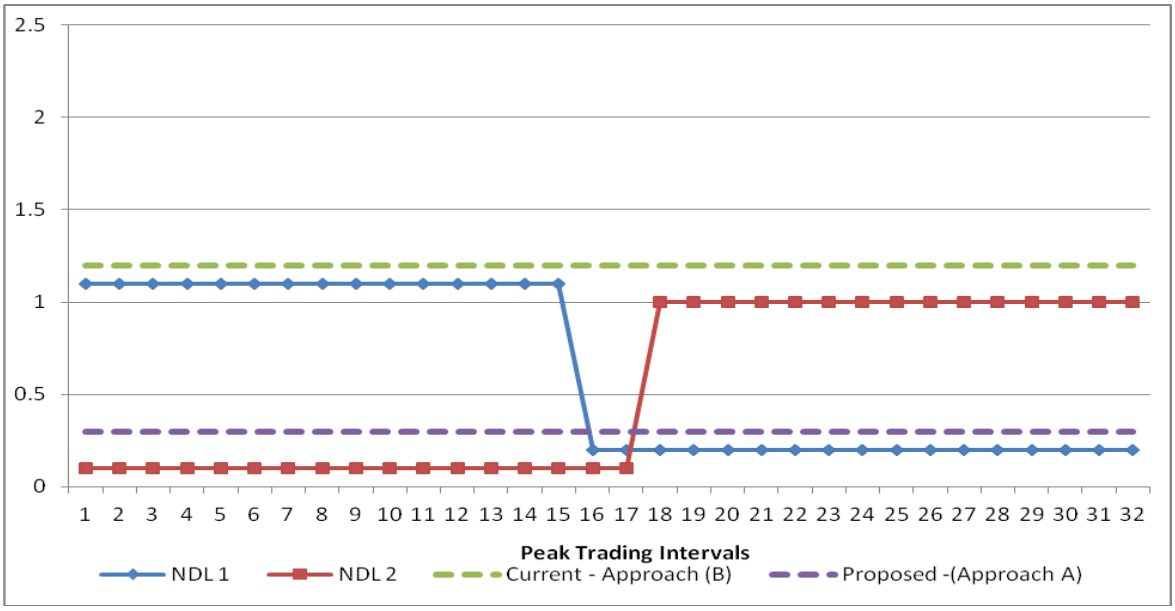
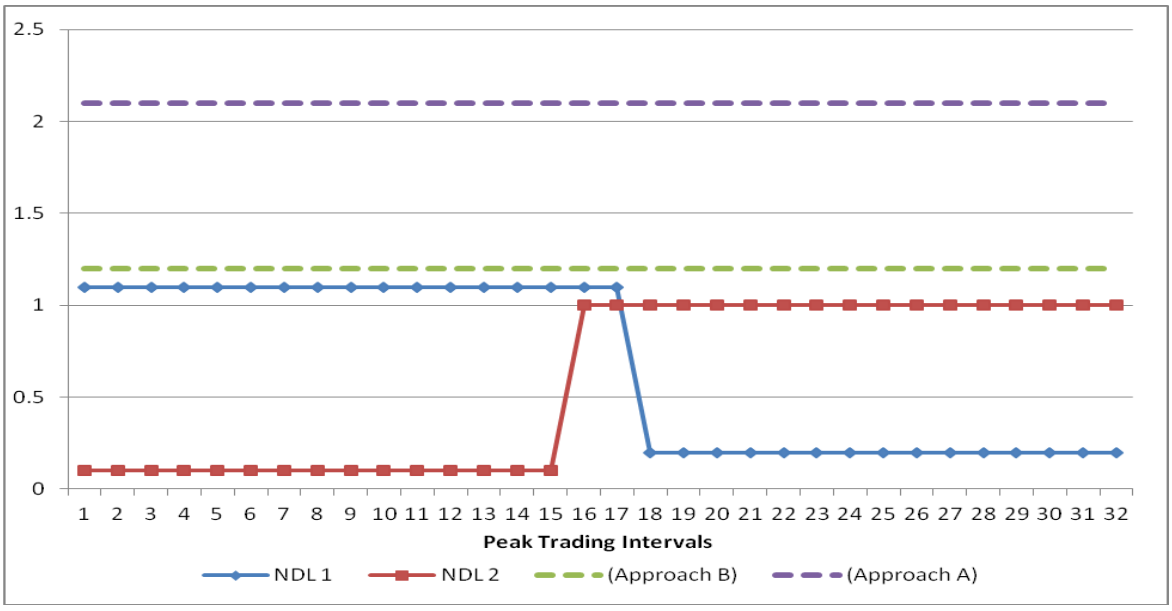


Figure 2: Comparison of Relevant Demand Approaches (A & B)



[6] Supporting data has been provided to the IMO as an addendum to this submission

Uncertainty, and Lack of Stability

As will be elaborated below, the portfolio RD calculated using Approach B is very sensitive to changes in the portfolio and can result in significant uncertainty for end-use customers. Practically, this means that the "value" of an end-use customer can be very different depending on what other loads are in the DSP.

Examining the example of Figure 1, if the DSP consisted only of NDL1, the portfolio RD would be 0.2MW. Adding NDL2 increases the portfolio RD to 1.2MW. It could then be considered that NDL2 contributed 1MW, however this is inaccurate and inequitable, as the result is derived simply because they were added after NDL1. Equally, if the DSP consisted only of NDL2, the portfolio RD would be 0.1MW. Adding NDL2 increases the portfolio RD to 1.2MW. It could then be considered that NDL1 contributed 1.1MW, which again is inaccurate and inequitable.

Summary - Figure 1

In First	RD (MW)	In Second	Portfolio RD Result (MW)	Marginal Value of Second Site (MW)
NDL1	0.2	NDL2	1.2	1
NDL2	0.1	NDL1	1.2	1.1

Conversely, in Figure 2, NDL1 alone gives an RD of 1.1MW. Adding NDL2 increases the portfolio RD to 1.2MW. Similarly, NDL2 alone gives an RD of 1MW and adding NDL1 increases the portfolio RD to 1.2MW. Subsequently, it could be considered that NDL2 is worth 0.2MW and NDL1 0.1MW, however, this again would be inaccurate and inequitable based upon the timing of their introduction to the DSP. Alternatively, the first associated load would need to be informed that their contribution is not as high as initially thought.

Summary - Figure 2

In First	RD (MW)	In Second	Portfolio RD Result (MW)	Marginal Value of Second Site (MW)
NDL1	1.1	NDL2	1.2	0.1
NDL2	1	NDL1	1.2	0.2

As DSPs introduce or remove loads from their program over time, the contribution of individual constituent loads to the DSPs RD requires significant recalculation with the result wholly dependent upon the order in which individual loads are introduced into the calculation.

Using Approach A, these problems do not occur: in the example of Figure 1, the portfolio RD is 0.3MW, and in the example of Figure 2 it is 2.1MW. Each NDL's contribution is easy to calculate, using data from that site alone, and *remains stable*.

Lack of Transparency

There is a problem with Approach B: since the result is sensitive to the correlation between the loads, you cannot calculate the contribution of any one NMI unless you have meter data for all the NMIs in the DSP.

This means that the IMO can calculate it, as can an aggregator, but an individual customer cannot.

It is important for an individual customer to be able to calculate their contribution to the portfolio RD, because it is this (less their minimum load) which determines the value they contribute to the DSP.

Under Approach A, this is a simple calculation that they can perform themselves; under Approach B, they have no way of doing this, and simply have to trust that an aggregator is dealing with them fairly: there is no transparency.

Furthermore, an aggregator is unable to calculate this figure using Approach B until they have identified, and obtained meter data for, all the other loads which will constitute the DSP. Until that point, the contribution of each load to the DSP is highly uncertain.

Key Concern with the Existing Approach

EnerNOC's key concern with the status quo is one of transparency. Poor transparency discourages engagement in DSM, as it would in any other part of the market. Without a clear relationship between the portfolio RD and an individual RD, a DSP's customers are in the dark – a DSP operator is unable to clearly and transparently inform their customers of their individual baselines – at best, they can give an estimate, but this will need to be revised continually as the portfolio is assembled.

Fundamentally, poor transparency impacts end-users – they have to *trust* a DSP about what the DSP says they contribute, and that number may change over time as the portfolio changes, for reasons that a DSP can't explain to them without breaching the privacy of other end users.

A lack of transparency makes the current approach highly complex – baselines should be simple enough for all stakeholders to understand, calculate, and implement, including end-use customers.

Moreover, the current approach risks incentivising behaviour that may be at odds with the Market Objectives. Ideally, when an aggregator assembles DSPs, they should be concerned principally with reliable performance. Approach B encourages aggregators to optimise their DSPs to bring about outcomes similar to Figure 2, while avoiding those similar to Figure 1. There's no advantage to the market from this optimisation effort, and decisions made to further it could hinder reliability.

EnerNOC contends that the approach adopted under the existing rules was not intended to result in a demonstrably volatile outcome for end-use customers that can directly impact the delivery of physical capacity to market and hence system reliability.

A 'Portfolio' Baseline

EnerNOC supports DAA's assertion that "the effect of aggregating data [is] secondary to the effect...caused by the different Relevant Demand Methodologies"[7] and notes that DAA did not question the validity of either approach.

If Approach B had some significant theoretical or practical advantage over Approach A, it might make sense to persist with it. However, this is not the case: having found no significant difference between the two approaches, Approach B was chosen on the basis that it might require less work. In practice the work required by the IMO for each approach is the same: they can be calculated by the same tool from the same data.

EnerNOC proposes that, so long as a static baseline methodology is to be used for assessing DSPs, Approach B should be replaced with Approach A, due to the practical and policy issues that have been raised in this submission. EnerNOC is of the firm belief that Approach A will better allow the Market Rules to achieve its objectives and will result in a transparent methodology that accurately accounts for changes to a DSP's structure and encourages engagement in DSM.

[7] DAA, Section 9, page 36

2. Explain the reason for the degree of urgency:

The current approach is a barrier to participation in the RCM and creates significant instability and uncertainty for existing and potential new customers

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

It is proposed that the following rule change be implemented:

4.26.2CA. The Relevant Demand of a Demand Side Programme for a Trading Day d in a Capacity Year is the sum of the median ~~median of the historical consumption quantities determined by the IMO for each of the 32 Trading Intervals identified under clause 4.26.2C(a) for the Capacity Year. The historical consumption quantity for each Trading Interval is the sum, over all the Associated Loads associated with the Demand Side Programme during Trading Day d,~~ of the MW ~~quantity~~ quantities determined by the IMO for each Associated Load and the Trading Interval under clause 4.26.2C(b).

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

The proposed rule change would better address the market objectives in the following ways:

i. Market Objective (a): By reducing complexity, improving transparency, and establishing a clear relationship between individual load baselines and a DSP's Relevant Demand, the change will improve the reliability and efficiency in the provision of capacity services in the SWIS;

ii. Market Objective (c): Through removing disincentives for efficient DSM portfolio management, the change would help avoid discrimination against sustainable energy options and technologies that reduce overall greenhouse gas emissions. Further, it would avoid discouraging DSM participation by end-use customers by providing a clear and meaningful baseline to measure their contribution;

iii. Market Objective (e): By improving transparency and establishing a clear relationship between an individual load's baseline and a DSP's Relevant Demand, end-use customers will be encouraged to take measures that manage the amount of electricity consumed during periods of system stress.

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

It is envisaged an overall reduction in costs will be experienced, through reduced complexity and requirements to mitigate "peak load losses", for both the IMO and DSP operators.

The simplification of the DSP Relevant Demand methodology and transparency involved in utilising the proposed rule change rather than that which exists at present will provide DSM program benefits for all customers / associated loads participating.

The change will encourage participation in the RCM and will lead to the efficient reduction in system peaks.

Agenda Item 5a: Overview of Market Rule Changes

Below is a summary of the status of Market Rule Changes that are either currently being progressed by the IMO or have been registered by the IMO as potential Rule Changes to be progressed in the future.

Rule changes: Formally submitted (see appendix 1)	**4 July 2012**
Fast track with Consultation Period open	0
Standard Rule Changes with 1st Submission Period Open	2
Fast Track Rule Changes with Consultation Period Closed (final report being prepared)	0
Standard Rule Changes with 1st Submission Period Closed (draft report being prepared)	1
Standard Rule Changes with 2nd Submission Period Open	0
Standard Rule Changes with 2nd Submission Period Closed (final report being prepared)	1
Rule Changes - Awaiting Minister's Approval and/or Commencement	1
Total Rule Changes Currently in Progress	**5**

Potential changes logged by the IMO- Not yet formally submitted	**May**	**June**
High Priority (to be formally submitted in the next 3/6 months)	0	0
Medium Priority (may be submitted in the next 6/12 months)	20	19 (+3/-4)
Low Priority (may be submitted in the next 12/18 months)	22	22 (+1/-1)
Potential Rule Changes (H, M and L)	**42**	**40**

The changes in the rule change issues log from May to June are outlined below:

Priority	Issue
High	N/a
Medium	**In:** • **Commissioning:** Clause 3.21A.2 and 3.21A.4 of the Market Rules when read together result in Market Participants not being able to apply for a Commissioning Test within 20BD of the test start date. Further System Management often does not require 20 Business Days to assess the security and reliability impacts of a generator conducting a Commissioning Test (as evidenced in the PSOP: Commissioning and Testing which allows System Management to accept Commissioning Tests within the 20 BD timeframe). The application of this 20 Business Day request obligation can potentially result in risks to power system security and reliability as a Market Participant may try to commission under a Resource Plan, resulting in an unreliable facility being treated as reliable by System Management which issuing Dispatch Instructions. The IMO notes that under the PSOP: Commissioning and Testing System Management may approve Commissioning Tests submitted less than 20 Business Days prior to the test start date but will report a breach of clause 3.21A.4 to the IMO. Clause 3.21A.2 is a civil penalty clause currently and so breaching the 20 Business Day requirement for applications for Commissioning Tests has serious consequences for Market Participants. The IMO considers that a Facility should be able to apply for a Commissioning Test earlier than the 20 Business Day requirement and that revisions to the details of Commissioning Tests should be allowed under the Market Rules. Further the IMO considers that the civil penalty attached to clause 3.21A.2 should be clarified to apply to the requirement for a Market Participant to request permission from SM for a commissioning test, rather than to the timing requirement. • **TES Equations:** Verve Energy is concerned that the Maximum and Minimum TES calculations cannot be altered. One of the key inputs into the TES calculations is a participant's Sent Out Metered Schedule, determined using SCADA data (in accordance with clause 6.15.3 of the Amending Rules). Verve Energy considers that incorrect SCADA data could potentially have a large impact on the TES calculations and therefore the Constrained On/Off payments which a Market Participant receives. To address this issue, it is proposed by Verve Energy that clause 6.15.4 of the Amending Rules, approved under RC_2011_10, be deleted thereby allowing a Market Participant to raise a Notice of Disagreement or Dispute regarding the TES calculations.

	• **Early Entry of Capacity:** To ensure that new capacity arrives prior to 1 October the window of entry for new capacity is between 1 June -1 October (as amended by RC_2009_11). Synergy states that in making the changes under RC_2009_11 the market recognised that conventional generation, as opposed to Demand Side Programmes (DSPs), is prone to being unreliable for several months after commissioning. The change of timing for entering the market was to reduce the risk that generation capability would be late entering the market and the IMO would be required to call a Supplementary Reserve Capacity auction. Synergy considers there is a technical difference between generation capacity and other forms of capacity such as DSPs and that this difference serves as a basis on which to differentiate access to early capacity payments. Synergy therefore proposes to remove the early entry payment for DSPs. **Out:** • **Network Control Service:** Under the current Market Rules a Facility that is subject to a Network Control Service Contract is not assigned Capacity Credits for its Certified Reserve Capacity. • **Commissioning:** As detailed above. • **TES Equations:** As detailed above. • **Early Entry of Capacity:** As detailed above.
Low	**In:** • **Metering Data Agents:** Metering Data agents (a class of Rule Participant) are not currently covered by any of the existing confidentiality classes under the Market Rules (as outlined in clause 10.2.2). This affects the confidentiality status of information created in several clauses in Chapter 8 of the Market Rules. The IMO consider that a new class of confidentiality that covers the Metering Data agent should be introduced to the Market Rules. **Out:** • **Procedure Change Proposals:** During the regulatory change process for RC_2011_10 the IMO put forward a proposal to make clause 2.10.2A a Reviewable Decision under the Regulations, following suggestions from industry. However as there is no clear decision made by the IMO or System Management with respect to a suggestion from another party that it would be appropriate to amend or replace a Market Procedure it was not possible to make this clause a Reviewable Decision under the Regulations. The IMO needs to amend clause 2.10.2A to clearly state that a decision is made and that where we decide not to progress the change that we will publish reasons for that decision.

The IMO also notes that it keeps a log of Minor and Typographical issues and Rule Change Suggestions that is updated on a regular basis. The Issues contained within the Minor and Typographical Log are collated and submitted in batches during the year. Rule Change Suggestions contained on the IMO's log form the basis for the Market Rules Evolution Plan.

APPENDIX 1: FORMALLY SUBMITTED RULE CHANGES (Current as of 4 July 2012)

Standard Rule Change with First Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2011_09	15/05/2012	Prudential Requirements	IMO	Submissions close	24/08/2012
RC_2012_10	22/06/2012	Limits to Early Entry Capacity Payments	Synergy	Submissions close	03/08/2012

Standard Rule Change with First Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2012_04	24/04/2012	Consequential Outage Correction	Tesla	Draft Rule Change Report Published	05/07/2012

Standard Rule Change with Second Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2012_01	29/02/2012	Intermittent Loads Eligibility Criteria	IMO	Final Rule Change Report Published	11/07/2012

Rule Changes with Final Rule Change Report Published

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2011_02	10/03/2011	Reassessment of Allowable Review during a Review Period	IMO	Ministerial Approval	03/07/2012

Wholesale Electricity Market
Pre- Rule Change Proposal

Change Proposal No: PRC_2012_06
Received date: TBA

Change requested by:

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Address:	Level 3, Governor Stirling Tower, 197 St Georges Terrace
Date submitted:	TBA
Urgency:	Fast Track Rule Change Process
Change Proposal title:	Clarification of Clause 2.10.2A
Market Rules affected:	Clauses 2.10.2A, 2.17.1 and 2.17.2

Introduction

Market Rule 2.5.1 of the Wholesale Electricity Market Rules provides that any person (including the IMO) may make a Rule Change Proposal by completing a Rule Change Proposal Form that must be submitted to the Independent Market Operator.

This Change Proposal can be posted, faxed or emailed to:

Independent Market Operator
Attn: Group Manager, Market Development
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax: (08) 9254 4339
Email: market.development@imowa.com.au

The Independent Market Operator 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 electricity 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 Market Rule Change

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

Background

The new Balancing and Load Following markets introduced a principles based drafting approach, resulting in a substantive amount of detail being included into the Market Procedures. During the development of the design of the new markets the IMO received suggestions from industry that the Procedure Change Process would need to be strengthened to enhance the current process outlined in section 2.10 of the Market Rules. In particular it was suggested that there should be more transparency with respect to decisions by the IMO and System Management following a suggestion from a Rule Participant under clause 2.10.2.

Subsequently the IMO incorporated into the Amending Rules for the Rule Change Proposal: Competitive Balancing and Load Following (RC_2011_10) a requirement for the IMO or System Management, as applicable, to publish details of its decision where it determines to not progress a Procedure Change Proposal following receipt of a suggestion under clause 2.10.2 (new clause 2.10.2A). The IMO also put forward a recommendation that the decision made by the IMO or System Management under clause 2.10.2A become a Reviewable Decision under the Electricity Industry (Wholesale Electricity Market) Regulations 2004 (Regulations). This would ensure procedure fairness when rejecting a proposed amendment or replacement of a Market Procedure.

Issue

During the regulatory change process for RC_2011_10 the Public Utilities Office (PUO) (formerly the Office of Energy) raised that it would not be possible to make new clause 2.10.2A a Reviewable Decision because as currently drafted clause 2.10.2A does not explicitly require a decision to be made by the IMO or System Management. A decision to progress a suggested change is only implicit

in the current drafting of this clause. Without the embedded requirement of a decision being made, the PUO suggested it would be inappropriate to make this clause a Reviewable Decision under the Regulations.

Based on the advice of the PUO the IMO determined to not progress a change to clause 2.10.2A in the Market Rules as part of the regulatory process for RC_2011_10, but rather to clarify clause 2.10.2A through the rule change process and then separately progress regulatory amendments to make decisions with respect to notifications under clause 2.10.2 a Reviewable Decision.

Proposal

The IMO proposes to amend clause 2.10.2A to:

- Explicitly make a decision as to whether to progress an amendment or replacement of a Market Procedure following receipt of a suggestion under clause 2.10.2.

- Clarify that a decision must be made by the IMO or System Management as to whether to progress a Procedure Change Proposal within 20 Business Days. The IMO considers that this will allow sufficient time for the IMO or System Management to consider the proposed changes and seek any necessary clarification. The IMO notes that extensions of this timelines will be possible under clause 2.10.17.

- Require publication on the Market Web Site of the IMO or System Management's decision to progress/not progress a Procedure Change Proposal to address the suggested change and reasons for the decision .The IMO notes that this will align more closely with the requirements for Rule Change Proposals under clause 2.5.7(e).

During the rule change process the IMO will work with PUO to progress the required amendments to the Regulations to ensure that a decision as to whether to progress a Procedure Change Proposal (as made under clause 2.10.2A(a)) will be a Reviewable Decision. As an extension of this reasoning the IMO will also put forward a recommendation requesting clause 2.5.7(e), which relates to decisions by the IMO on whether to progress a Rule Change Proposal, to also be made a Reviewable Decision under the Regulations.

The IMO notes that it has proposed updates to clause 2.17.1 (which lists Reviewable Decisions) and clause 2.17.2 (which lists decisions subject to procedural review) to reflect that clauses 2.10.2A(a) and 2.5.7(e) would be Reviewable Decisions that are subject to a Procedural Review.

The proposed amendments to the Market Rules outlined in this Rule Change Proposal along with the proposed amendments to the Regulations will ensure procedural fairness with respect to:

- the IMO and System Management's decisions relating to the progression of a proposed amendment or replacement of a Market Procedure put forward by a Rule Participant; and

- the IMO's decisions relating to the progression of a proposed change to the Market Rules.

The IMO considers it is appropriate that in these instances the Electricity Review Board can be requested to reconsider the process surrounding the IMO or System Management's (as applicable) decision as it will provide appropriate oversight over both entities decision making processes.

---

2. Explain the reason for the degree of urgency:

The IMO submits that this Rule Change Proposal should be fast-tracked, on the basis that it satisfies the criteria in clauses 2.5.9(a) of the Market Rules.

Clause 2.5.9 states:

> *The IMO may subject a Rule Change Proposal to the Fast Track Rule Change Process if, in its opinion, the Rule Change Proposal:*
>
> *(a) is of a minor or procedural nature;*
>
> (b) *is required to correct a manifest error; or*
>
> (c) *is urgently required and is essential for the safe, effective and reliable operation of the market or the SWIS.*

The IMO submits that the Rule Change Proposal should be subject to the Fast Track Rule Change Process as it is of a procedural nature. The proposed amendments will clarify the procedure to be followed by the IMO or System Management when a Rule Participant suggests an amendment or replacement of a Market Procedure and does not impact on the intended substantive effect of the clause.

The IMO notes that the changes only amend this aspect of the Procedure Change Process and not the operation of the Market. There will be no financial consequences as a result of the proposed amendments. Likewise there will be no operational impacts.

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

2.10.2A. ~~Where the IMO or System Management has decided not to amend or replace a Market Procedure following a notification under clause 2.10.2, the IMO or System Management, as applicable, must publish reasons for that decision on the Market Web Site.~~ Within 20 Business Days of receipt of a notification under clause 2.10.2, the IMO or System Management, as applicable, must:

(a) determine whether an amendment or replacement to a Market Procedure is appropriate; and

(b) publish on the Market Web Site details of whether a Procedure Change Proposal will be progressed with respect to the suggested amendment or replacement of a Market Procedure and the reasons for that decision.

2.17.1. Decisions by the IMO or System Management, as applicable, made under the following clauses are Reviewable Decisions:

(a) clause 2.3.8;

(b) clauses 2.5.7(e) and 2.5.9;

(c) clause 2.6.4(f);

(d) clause 2.7.8(e);

(e) clause 2.10.2A(a);

(f) clause 2.10.13;

(g) clause 2.10.14;

(h) clause 2.13.28;

(i) clause 2.28.16;

(j) clauses 2.30.4 and 2.30.8;

(k) clause 2.31.10;

(l) clause 2.32.7E(b);

(m) clause 2.34.7;

(n) clause 2.34.7A(b)(ii);

(o) clause 2.34.7C(c);

(p) clause 2.34.11;

(q) clauses 2.37.1 to 2.37.3;

(r) clause 4.9.9;

(s) clause 4.15.1;

(t) clause 4.27.7;

(u) clause 4.28.7;

(v) clause 7A.1.11; and

(w) clause 10.2.1.

2.17.2. Decisions by the IMO or System Management made under the following clauses may be subject to a Procedural Review:

(a) clauses 2.5.7(e), 2.5.9, 2.6.4(f) and 2.7.8(e); and

(b) clauses 2.10.2A(a), 2.10.13, 2.10.14.

---

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

The IMO considers that the proposed changes, which will improve the integrity and clarity of the Market Rules, are consistent with the Wholesale Market Objectives.

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

Costs:

No costs associated with implementing these proposed changes have been identified.

Benefits:

Decisions on the progression of Proposals for Market Rules and Market Procedures will become Reviewable Decisions. In addition, the proposed changes will provide sufficient clarity to allow the PUO to propose that clause 2.10.2A becomes a Reviewable Decision under the Regulations. This will result in procedural fairness being awarded to Rule Participants and will align clause 2.17.1 with the Reviewable Decisions listed in Schedule 2 of the Regulations.

Wholesale Electricity Market
Pre- Rule Change Proposal

Change Proposal No: PRC_2012_11
Received date: TBA

Change requested by:

Name:	Fiona Edmonds
Phone:	(08) 9254 4350
Fax:	(08) 9254 4399
Email:	market.development@imowa.com.au
Organisation:	IMO
Address:	Level 3, Governor Stirling Tower, 197 St Georges Terrace
Date submitted:	TBA
Urgency:	Standard Rule Change Process
Change Proposal title:	Transparency of Outage Information
Market Rules affected:	3.18.6, 10.5.1 and the Glossary, and new clauses 7.13.1D, 7.13.1E, 7.13.1F, 7.13.1G

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

Details of the proposed Market Rule Change

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

Background

In accordance with clause 3.18.18 of the Wholesale Electricity Market (WEM) Rules (Market Rules), during 2011 the Independent Market Operator (IMO) completed the first five year review of the outage planning process (2011 Outage Planning Review) as described in the Market Rules and supported by the Power System Operation Procedure: Facility Outages (PSOP).

The review, completed by PA Consulting in October 2011, assessed the performance of the outage planning process since market start against the Wholesale Market Objectives. Overall, PA Consulting concluded the WEM outage planning process was working well, but could benefit from some "fine tuning" in the areas of outage planning information transparency and the technical functioning of the outage planning process.[1]

In line with the recommendations of PA Consulting, the IMO is currently considering reforms to the outage planning process which include greater transparency of outage planning information to the market. The reforms to the outage planning process will be considered via the following phased approach:

- The first set of reforms are being progressed via this Rule Change Proposal and are intended to introduce new standards for the disclosure of information relating to outages, aimed at improving transparency in the market. Advancements to the level of information disclosure are expected to improve pricing efficiency and risk management.
- The second phase of the reform process will consider technical changes to the process aimed at bringing greater flexibility to Market Participants in outage planning. It is anticipated that

[1] PA Consulting, 2011, Independent Market Operator – Five Year Outage Planning Review – Final Report, p. iii

phase two will be progressed by the IMO in consultation with the Market Advisory Committee during mid/late 2012.

Note that the ordering of reforms reflects the IMO's position that increased information transparency in the WEM will deliver significantly broader reaching benefits and improve the IMO's ability to assess future technical changes.

Issue: Disclosure of outage information

As noted above, during the 5 Year Review of the Outage Planning Process PA Consulting recommended the IMO, in conjunction with System Management, consider reforms to improve the disclosure of outage information. It was noted that "*the disclosure of information in a timely and accessible manner can go a long way in effecting the efficient allocation of outages over time*."[2]

PA Consulting recommended that amendments should be made to the Market Rules and the PSOP on the presumption that all information related to outages and outage planning should be made public by the IMO and System Management.

The IMO notes that System Management does already disclose certain information about Planned Outages, even in the absence of any requirement in the Market Rules or the PSOP in some circumstances. However, the IMO recognises that, at times, a lack of transparency may have resulted in sub-optimal outcomes for Market Participants and energy consumers.

PA Consulting specified that any amendments should consider the following:

- the type of information to be made available, including:
    - the status of the Planned Outage, the equipment affected, the time periods affected, the capacity involved and the resultant net operating margin;
    - information on historic Forced and Planned Outages; and
    - information on major network outages, including if any generating facilities are unable to generate due to the network outage;
- the frequency with which the information is refreshed or updated; and
- the form and mode by which the information is made available.[3]

Proposal

The IMO agrees with, and accepts, PA Consulting's recommendations with respect to increasing the transparency of outage information. Specific details of the IMO's proposed changes to implement greater transparency in this area of the market are outlined below:

Type of information

For each Planned Outage the IMO proposes that the following information be published:

- the facility or item of equipment on outage (clause 3.18.6(a));

[2] PA Consulting, 2011, Independent Market Operator – Five Year Outage Planning Review – Final Report, p. 44
[3] PA Consulting, 2011, Independent Market Operator – Five Year Outage Planning Review – Final Report, p. 50

- outage sub-type (Scheduled Outage, Opportunistic Maintenance);
- the reasons for the outage (clause 3.18.6(c));
- the quantity of capacity on outage (clause 3.18.6(b))[4];
- the time period of the outage (i.e. impacted Trading Intervals) (clause 3.18.6(d) and updated in accordance with the processes outlined in clauses 3.18.13, 3.18.15, 3.18.16);
- the assessment of the risks that might extend the outage (clause 3.18.6(e));
- details of the time it would take the Facility or item or equipment to return to service, if required (clause 3.18.6(f));
- any Outage Contingency Plans (clause 3.18.6(g));
- the actual start and end times for the outage (where these vary from what was originally provided under clause 3.18.6 or amended under clauses 3.18.13, 3.18.15 and 3.18.16).
- time and date when:
    - the outage request was lodged with System Management;
    - the outage status changed (i.e. acceptable, unacceptable, acceptable under certain conditions, approved, rejected) (clause 3.18.13). The IMO also proposes to define "Outage Status" in the Glossary of the Market Rules to ensure that simplified drafting can be adopted for implementing the changes; and
    - the Planned Outage was approved or rejected by System Management.

For each Forced Outage or Consequential Outage, the IMO proposes to publish:

- the facility or item of equipment on outage (clause 3.21.4(a));
- the cause of the outage (clause 3.21.4(c));
- outage type. Note that Forced Outages and Consequential Outages will not be confirmed until 15 Business Days after the event;
- the quantity of capacity on outage (clause 3.21.4(e));
- start time and date, and expected end time and date of the outage (clauses 3.21.4(a) and 3.21.4(b)). Note that this information will be confirmed within 15 Business Days of logging the outage under clause 3.21.7;
- whether the outage is a Forced Outage or Consequential Outage; and
- time and date when:
    - the outage was first notified to System Management;
    - the outage status changed (i.e. cancelled); and

[4] Note that for generating systems this quantity is determined in accordance with clause 3.21.5.

- System Management determined that a Consequential Outage occurred.

The IMO notes that the information proposed to be published for all outage types is information that Market Participants are already required to provide under clauses 3.18, 3.19 and 3.21 of the Market Rules.

Access to information

Given the broad market value of information on outage planning the IMO proposes that the information be made publically available. The IMO notes that this is consistent with the current classification of schedules of Planned Outages as being public under clause 10.5.1(D).

Form and mode of publication

The information will be published on the Market Web Site. To allow interested parties to best understand the IMO's proposal, a draft user interface has been prepared, including a graphical representation of the interface. A copy of the draft user interface has been provided as Appendix 1 to this proposal.

Frequency of publication

The IMO proposes that the information for outages, as outlined above, be published as soon as it becomes available to System Management. This will allow for relevant updates to outages to be provided through to industry in a timely fashion, thereby enabling faster responses by Market Participants.

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2. Explain the reason for the degree of urgency:

The IMO submits that this Rule Change Proposal should be progressed via the Standard Rule Change Process.

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

3.18.6. The information submitted in an Outage Plan must include:

(a) the identity of the Facility or item of equipment that will be unavailable;

(b) the quantity of any de-rating for each Trading Interval where, if the Facility is a generating system, this quantity is in accordance with clause 3.21.5;

(c) the reason for the outage;

(d) the proposed start and end times of the outage;

(e) an assessment of risks that might extend the outage;

(f) details of the time it would take the Facility or item of equipment to return to service, if required; and

(g) contingency plans for the early return to service of the Facility or item of equipment("**Outage Contingency Plans**").

7.13.1D. System Management must as soon as practicable after:

(a) System Management receives a request for a Planned Outage; or

(b) any event occurs which results in a change to the information described in clause 7.13.1E,

provide to the IMO any relevant new or amended information outlined in clause 7.13.1E.

The IMO notes that it will work with System Management during the progression of this Rule Change Proposal to determine the structure of the information to be provided under clause 3.18.6 and whether this will be in an appropriate format for publication. The IMO notes that changes to the Market Rules to reflect the outcomes of these discussions may be required.

7.13.1E The information required to be provided by System Management to the IMO under clause 7.13.1D must include:

(a) whether the request is for a Scheduled Outage or Opportunistic Maintenance;

(b) the information provided under clause 3.18.6;

(c) the time and date when:

i. the Outage Plan was received by System Management;

ii. the Outage Status was amended by System Management; and

iii. the Planned Outage was approved or rejected by System Management; and

(d) the actual start and end times of the outage as reflected in System Management's outage schedule, if these vary from the proposed start and end date and time provided under clause 3.18.6(d).

7.13.1F. System Management must as soon as practicable after:

(a) System Management receives a notification of a Forced Outage or Consequential Outage; or

(b) any event occurs which results in a change to the information described in clause 7.13.1G,

provide to the IMO any relevant new or amended information outlined in clause 7.13.1G.

7.13.1G. The information required to be provided by System Management to the IMO under clause 7.13.1F must include:

(a) whether the outage is considered to be a Forced Outage or Consequential Outage;

(b) the information provided under clause 3.21.4 and updated under clause 3.21.7;

(c) the time and date when:

i. the Forced Outage or Consequential Outage was first notified to System Management;

ii. the Outage Status was amended by System Management; and

iii. System Management determined whether a Consequential Outage occurred under clause 3.21.2; and

(d) the actual end time of the outage, if this varies from the estimated end time for the outage provided under clause 3.21.4(b).

10.5.1. The IMO must set the class of confidentiality status for the following information under clause 10.2.1, as Public and the IMO must make each item of information available from the Market Web Site after that item of information becomes available to the IMO:

…

(zC) summary information on Disputes in progress that may impact other Rule Participants;

(zD) ~~schedules of Planned Outages;~~ the information outlined in clauses 7.13.1E and 7.13.1G;

(zE) the current Non-Balancing Dispatch Merit Order;

(zF) audit reports;

(zG) documentation of the functionality of:

i. any software used to run the Reserve Capacity Auction;

ii. the STEM Auction software; and

iii. the Settlement System software; and

(zH) information relating to Commissioning Tests which is supplied under clause 3.21A.16 by System Management.

The IMO notes that it will work with System Management directly during the consultation period for this rule change to ensure that all statuses of outages are adequately covered by this definition

Chapter 9

Outage Status: The status of any outage received or notified to System Management which may include requested, acceptable, unacceptable, acceptable under certain circumstances, approved, rejected and cancelled.

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

The IMO considers that information transparency is an integral part of achieving all the Market Objectives. In particular, the IMO considers improved transparency around outage planning will result in improved economic efficiency in electricity generation (Market Objective (a)), and improved efficiency in price outcomes for consumers (Market Objective (d)).

By improving outage planning information transparency, existing and potential new generators will be able to build a more complete picture, and have a better understanding, of the generation sector in WA. In turn, this should lead to a more efficient allocation of resources (including investment in new capacity) and improved generation operations, resulting in improved efficiency in consumer price outcomes. In particular, by providing for transparency of outages in real time Market Generators will be able to appropriately react to market signals. For example advanced transparency of a Planned Outage of a large base load generator during the shoulder periods will provide signals to other base load and mid-merit generators to re-organise planned maintenance for over the same time period and bid into the STEM and Balancing Market during the impacted Trading Intervals. Greater transparency of outages will allow the market to self sort and determine the appropriate mix of generation providing energy thereby promoting efficient pricing outcomes while ensure system reliability is maintained.

Additionally the proposed reforms to improve the transparency of outage planning information will continue to add to part of a larger and ongoing work program by the IMO to increase the transparency and availability of market related information in the WEM.

---

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

Costs:

- There will be IT costs to both the IMO and System Management associated with the proposed changes. The IMO will work with System Management during the formal rule change process to identify these costs.

Benefits:

- Improved transparency of outage information which will result in improved economic efficiency in electricity generation and pricing outcomes.
- Enable Market Generators to appropriately react to changes in market signals.
- Allow the market to self sort and determine the appropriate mix of generation providing energy.

1 USER INTERFACE

1.1 Facility Outage Timeline

1.1.1 General Layout

The Outage Timeline page uses a three column layout, as seen in Figure 1 below. A left column of fixed-width contains the Search section. The right column of fixed width contains the Outage Detail section. The middle column is of variable-width, utilising the remaining available white space, and is used for the Outage Timeline. The location of the various controls is also indicated.

1.1.2 Search Function

The Search function allows the user to specify a given Trading date, as seen in Figure 1, to use as starting point for the display of the Outage Timeline. The following section describes the search options available to the user.

1.1.2.1 Output

The Search options include choosing either to Display the search results on the given page, or to Download the results to a local file. This selection is made via radio controls, as described in Table 2. The Display option will be chosen by default upon loading the Outage page.

1.1.2.2 Outage Date

The Search options include specifying the Outage Date via the Date form text entry field, as described in Table 2. Upon clicking on the calendar icon, to the right of the text fields, a separate user friendly date picker interface is displayed on the top layer, allowing the user to select a date. Manual keyboard entry of dates in the text field is also allowed. To take into account the possibility of erroneous manual entries, inline field validation will be performed. Users can select both future and historic dates with no system limitations. Historic data availability however will be based on WEMS data retention policies.

1.1.2.3 Scale

The Search options include choosing the scale, and therefore date range, of the Outage Timeline. This selection is made via radio controls, as described in Table 2. The Monthly option will be chosen by default upon loading the Outage page. The ranges are described in Table 1 and may require adjustment based on system performance or participant requirements.

Table 1

SCALE	Range Visible	Historic Data Returned	Future Data Returned
Daily	1 ½ days	2 days	3 days
Monthly	1 ½ months	1 month	2 months
Yearly	1 year	6 months	2 years

1.1.2.4 Sort By

The Search options include selecting the sort order of the Outage Timeline. This selection is made via drop down controls, as described in Table 2. The Fuel Type option will be chosen by default upon loading the Outage page.

1.1.2.5 Group By

The Search options include selecting the grouping of the Facilities in the Outage Timeline. This selection is made via drop down controls, as described in Table 2. The Participant option will be chosen by default upon loading the Outage page.

1.1.2.6 Display Cancelled/Rejected

The Search options include changing the visibility of Cancelled and/or Rejected Outages of the Facilities in the Outage Timeline. This selection is made via check box controls, as described in Table 2. No boxes will be checked by default upon loading the Outage page.

1.1.2.7 Submit Button

The Submit button is located on the bottom of the Search options and is required to be clicked before submission of the Search request occurs. Upon clicking the button, the control will appear dimmer to give an indication that the request is in progress. The control will return to its normal state when the request has been completed.

1.1.2.8 Search Query

Parameters supplied by the search form fields will be used to perform a query to the web service, and in turn a resulting data set describing the desired Outage Timeline will be sent to the Outage Timeline display. All Outage information will be retrieved in a single query to the system.

Table 2

Control Name	Description	Control Type	Control Values	Default Value
Output	Requested output for the resulting data set.	Radio Control	Display CSV Download XML Download	Display
Date	Trading Day to be the focus of the Outage Timeline.	Text Field	DD/MM/YYYY	Current Trading Day
Scale	Scale of the Outage Timeline. Scale is centred on selected Trading Date.	Radio Control	• Yearly – returns 1 1/2 years of data. • Monthly – returns 2 months of data. • Daily – returns 2 days of data.	Monthly
Sort By	Sort of Facilities in Outage Timeline	Drop Down Selection	• Facility Name • Participant Name • Fuel Type	Facility Name
Group By	Grouping of Facilities in the Outage Timeline	Drop Down Selection	• Facility • Participant • Fuel Type	Participant Name
Display Cancelled/Rejected	Toggles the display of Cancelled and/or Rejected Outages	Check Box Selections	• Rejected – will display all Rejected Outages • Cancelled – will display all Cancelled Outages	No boxes checked

1.1.3 Outage Timeline

The Outage Timeline panel displays a simplified Gantt chart of the outages in the market as a whole, for a given trading date range. Each bar represents an Outage with its size

representational of its duration, and colour of its type. The chart is determined by querying all outages for a range selected by the Scale search option. This section is implemented using a charting component containing the data series as specified in Table 3.

If a Facility has more than one outage present in the Timeline range, two outage bars will be displayed in the same row.

Table 3

Data Series	Description	Data Type
Outages	Contains the Outage information for the Outage Timeline corresponding to the chosen trading date range.	Array of Outage start and end times.

1.1.3.1 Panning Capability

The charting component is interactive allowing the user to pan the chart through mouse interactions. This allows the user to explore the full date range of the Scale selected in the Search options.

A region of Panning of the graph will be accessible by using the horizontal and vertical scrollbars located at the edges of the charting element.

1.1.3.2 Bar Selection

The charting component allows the user to click on an Outage bar which will then populate the Outage Details data grid with the corresponding information.

1.1.3.3 Hover Totals

The charting component is interactive allowing the user to determine the total quantity of MW on Outage. When a user hovers their cursor over a time interval (day in Month view, hour in Daily view), the totals display beneath the timeline as a MW total on Outage. This total does not include Outages with a status of Cancelled or Rejected. See Figure 2 below.

1.1.3.4 Legend

A legend will be displayed on the charting component as a reference for the different Outage types. The bars for each of these Outage types will be distinguishable from each other due to the difference in their colour.

1.1.3.5 Bar Pattern

The Outage bars will be patterned based on whether they have been completed. For completed Outages, bars a hashed patterned will be applied. Conversely, for future Outages, bars will be without pattern.

1.1.4 Outage Details

The Outage Details panel displays a tabular view of an Outage when the specified Outage is selected in the Timeline panel. The panel is populated with the latest queried data for the selected Outage at the time of selection. This section is implemented using a component containing the data series as specified in Table 4

Table 4

Column	Description	Data Type
Participant	Participant Name	String
Facility	Facility Name	String
Start Interval	Start Interval of Outage. This value will use the Actual Start Interval if available, otherwise the Planned Start	Date (DD/MM/YYYY HH24:MI)

	Interval will be used.	
End Interval	End Interval of Outage This value will use the Actual End Interval if available, otherwise the Planned End Interval will be used.	Date (DD/MM/YYYY HH24:MI)
Reason	Outage Reason (Planned, Forced, Consequential) If Outage is Planned, the sub-reason is also included. (Day Ahead, Opportunistic)	String
Capacity On Outage	Amount of Capacity in MW reduced by Outage	Number
Recovery Time	Recovery Time – Time required to return Facility back from Outage	Number
Description	Description of reason for Outage	String
Status	Outage approval status (Accepted, Approved, Rejected, Cancelled)	String
Approved On	Date/Time of approval by System Management	Date (DD/MM/YYYY HH24:MI)
Contingency Plan	Outage contingency plans	String
Created Date	Date that Outage was lodged into System Managements SMITTS system by Participant.	Date (DD/MM/YYYY HH24:MI)
Last Update	Date that Outage was last transferred to IMO from System Management	Date (DD/MM/YYYY HH24:MI)

Figure 1 - Monthly Scale

Figure 2 – Daily Scale

Figure 3 – Yearly Scale

1.2 Equipment Outage Timeline

1.2.1 General Layout

The Equipment Timeline page uses a three column layout, as seen in Figure 4 below. A left column of fixed-width contains the Search section. The right column of fixed width contains the Outage Detail section. The middle column is of variable-width, utilising the remaining available white space, and is used for the Outage Timeline. The location of the various controls is also indicated.

1.2.2 Search Function

The Search function allows the user to specify a given Trading date, as seen in Figure 4Figure 1, to use as starting point for the display of the Outage Timeline. The following section describes the search options available to the user.

1.2.2.1 Output

The Search options include choosing either to Display the search results on the given page, or to Download the results to a local file. This selection is made via radio controls, as described in Table 6. The Display option will be chosen by default upon loading the Outage page.

1.2.2.2 Outage Date

The Search options include specifying the Outage Date via the Date form text entry field, as described in Table 6Table 2. Upon clicking on the calendar icon, to the right of the text fields, a separate user friendly date picker interface is displayed on the top layer, allowing the user to select a date. Manual keyboard entry of dates in the text field is also allowed. To take into account the possibility of erroneous manual entries, inline field validation will be performed. Users can select both future and historic dates with no system limitations. Historic data availability however will be based on WEMS data retention policies.

1.2.2.3 Scale

The Search options include choosing the scale, and therefore date range, of the Outage Timeline. This selection is made via radio controls, as described in Table 5. The Monthly option will be chosen by default upon loading the Outage page. The ranges are described in Table 1 and may require adjustment based on system performance or participant requirements.

Table 5

SCALE	Range Visible	Historic Data Returned	Future Data Returned
Daily	1 ½ days	2 days	3 days
Monthly	1 ½ months	1 month	2 months
Yearly	1 year	6 months	2 years

1.2.2.4 Sort By

The Search options include selecting the sort order of the Outage Timeline. This selection is made via drop down controls, as described in Table 6. The Equipment Name option will be chosen by default upon loading the Outage page.

1.2.2.5 Group By

The Search options include selecting the grouping of the equipment in the Outage Timeline. This selection is made via drop down controls, as described in Table 6. The Equipment Type option will be chosen by default upon loading the Outage page.

1.2.2.6 Display Cancelled

The Search options include changing the visibility of Cancelled Outages of Equipment in the Outage Timeline. This selection is made via check box controls, as described in Table 6. No boxes will be checked by default upon loading the Outage page.

1.2.2.7 Submit Button

The Submit button is located on the bottom of the Search options and is required to be clicked before submission of the Search request occurs. Upon clicking the button, the control will appear dimmer to give an indication that the request is in progress. The control will return to its normal state when the request has been completed.

1.2.2.8 Search Query

Parameters supplied by the search form fields will be used to perform a query to the web service, and in turn a resulting data set describing the desired Outage Timeline will be sent to the Outage Timeline display. All Outage information will be retrieved in a single query to the system.

Table 6

Control Name	Description	Control Type	Control Values	Default Value
Output	Requested output for the resulting data set.	Radio Control	Display CSV Download XML Download	Display
Date	Trading Day to be the focus of the Outage Timeline.	Text Field	DD/MM/YYYY	Current Trading Day
Scale	Scale of the Outage Timeline. Scale is centred on selected Trading Date.	Radio Control	• Yearly – returns 1 1/2 years of data. • Monthly – returns 2 months of data. • Daily – returns 2 days of data.	Monthly
Sort By	Sort of Facilities in Outage Timeline.	Drop Down Selection	• Equipment Name • Equipment Type	Facility Name
Group By	Grouping of Facilities in the Outage Timeline	Drop Down Selection	• Equipment Name • Equipment Type	Participant Name
Display Cancelled	Toggles the display of Cancelled Outages	Check Box Selections	• Cancelled – will display all Cancelled Outages	Box unchecked

1.2.3 Outage Timeline

The Outage Timeline panel displays a simplified Gantt chart of the outages in the market as a whole, for a given trading date range. Each bar represents an Outage with its size representational of its duration, and colour of its type. The chart is determined by querying all outages for a range selected by the Scale search option. This section is implemented using a charting component containing the data series as specified in Table 7.

If a piece of equipment has more than one outage present in the Timeline range, two outage bars will be displayed in the same row.

Table 7

Data Series	Description	Data Type
Outages	Contains the Outage information for the Outage Timeline corresponding to the chosen trading date range.	Array of Outage start and end times.

1.2.3.1 Panning Capability

The charting component is interactive allowing the user to pan the chart through mouse interactions. This allows the user to explore the full date range of the Scale selected in the Search options.

A region of Panning of the graph will be accessible by using the horizontal and vertical scrollbars located at the edges of the charting element.

1.2.3.2 Bar Selection

The charting component allows the user to click on an Outage bar which will then populate the Outage Details data grid with the corresponding information.

1.2.3.3 Legend

A legend will be displayed on the charting component as a reference for the different Outage types. The bars for each of these Outage types will be distinguishable from each other due to the difference in their colour.

1.2.3.4 Bar Pattern

The Outage bars will be patterned based on whether they have been completed. For completed Outages, bars a hashed patterned will be applied. Conversely, for future Outages, bars will be without pattern.

1.2.4 Outage Details

The Outage Details panel displays a tabular view of an Outage when the specified Outage is selected in the Timeline panel. The panel is populated with the latest queried data for the selected Outage at the time of selection. This section is implemented using a component containing the data series as specified in Table 8

Table 8

Column	Description	Data Type
Owner	Equipment Owner	String
Equipment	Equipment Name	String
Equipment Type	Equipment Type (Circuit, Transformer, Circuit Breaker, Other)	String
Location	Location of equipment (or associated location for circuits)	String
Start Interval	Start Interval of Outage. This value will use the Actual Start Interval if available, otherwise the Planned Start Interval will be used.	Date (DD/MM/YYYY HH24:MI)
End Interval	End Interval of Outage This value will use the Actual End Interval if available, otherwise the Planned End Interval will be used.	Date (DD/MM/YYYY HH24:MI)

Reason	Outage Reason (Planned, Forced)	String
Outage Type	Details of Outage type (Full, Partial)	String
Description	Description of reason for Outage	String
Status	Outage approval status (Accepted, Approved, Cancelled)	String
Approved On	Date/Time of approval by System Management	Date (DD/MM/YYYY HH24:MI)
Contingency Plan	Outage contingency plans	String
Created Date	Date that Outage was logged into System Managements SMITTS.	Date (DD/MM/YYYY HH24:MI)
Last Update	Date that Outage was last transferred to IMO from System Management	Date (DD/MM/YYYY HH24:MI)

Figure 4 – Monthly Scale

2 PROPOSED INTERFACE WITH SYSTEM MANAGEMENT

FACILITY_OUTAGES

Transfer Timing: As soon as possible after new Outage information becomes available.

Description: The table below lists data elements to store Facility Outage information. These Outages include all Facility Outages.

Outage files will transfer updates to Outage records with transferred fields overwriting any previously received values. It is expected that System Management will reflect all changes to Outage information, including ex-post information in these files.

Data Integrity: The IMO will not be performing detailed data validation on the files received by System Management, as it is expected that System Management will perform data integrity checks internally before transferring.

OUTAGE_ID is a unique record specific to an associated RES_ID. There are no restrictions on a Resource having more than one OUTAGE_ID associated with it. Accordingly, overlapping of two Outages for a Resource may occur and will be allowed, as SM will have ensured that the concurrent Outages are valid.

Files transferred containing records with existing OUTAGE_IDs will overwrite previously transferred values.

On rejection of Outage by System Management, or cancellation of Outage by the Participant, the IMO will continue to retain the previously transferred information.

FACILITY_OUTAGES (Data Elements)

XML Data Set Element Name	Description	Data Type	Constraints
OUTAGE_ID	Unique identifier of each Outage.	NUMBER(15,0)	UK, NN
RES_ID	Unique identifier for the resource.	NUMBER (15,0)	NN
OUTAGE_REASON_FLAG	Outage Reason Flag. Values are: • P – Planned; • F – Forced; • C - Consequential	CHAR(1)	NN
MAINTENANCE_FLAG	Reason for Planned Outage Reason • D – Day Ahead • O – Opportunistic Maintenance	Char(1)	
START_INTERVAL_PLANNED	Starting Interval of the Outage as Planned.	DATE (DD/MM/YYYY HH:MI)	NN
END_INTERVAL_PLANNED	End Interval of the Outage as Planned.	DATE (DD/MM/YYYY HH:MI)	NN
START_INTERVAL_ACTUAL	Actual Starting Interval of the Outage as recorded.	DATE (DD/MM/YYYY HH:MI)	
END_INTERVAL_ACTUAL	Actual End Interval of the Outage as recorded.	DATE (DD/MM/YYYY HH:MI)	
OUTAGE_MW	Outage MW	NUMBER(9,3)	NN
OUTAGE_DESC	Outage Description	VARCHAR2(250)	
APPROVAL	A – Approved P – Accepted (Awaiting Approval) L – Lodged R – Rejected C – Cancelled.	CHAR(1)	NN

XML Data Set Element Name	Description	Data Type	Constraints
APPROVAL_DATE	Date and time of SM approval status change.	DATE (DD/MM/YYYY HH:MI)	
RECOVERY_TIME	Recovery Time in Minutes. (Used In case emergency restoration)	NUMBER(6,0)	
RISK_ASSESSMENT	Risk Assessment	VARCHAR2(250)	
OUTAGE_CONTINGENCY_PLAN	Outage Contingency Plan	VARCHAR2(250)	
CREATION_TIME	Record Creation Date. Timestamp when Outage request is received by System Management from Participant.	DATE (DD/MM/YYYY HH24:MI:SS)	NN
LAST_UPDATE_TIME	Last System Updated Date and Time as it was updated in SMITTS.	DATE (DD/MM/YYYY HH24:MI:SS)	NN

EQUIPMENT_OUTAGES

Transfer Timing: As soon as possible after new Outage information becomes available.

Description: The table below lists data elements to store Equipment Outage information. These Outages include all Outages of Equipment detailed in the Equipment List on the IMO website.

Outage files will transfer updates to Outage records with transferred fields overwriting any previously received values. It is expected that System Management will reflect all changes to Outage information, including ex-post information in these files.

Data Integrity: The IMO will not be performing detailed data validation on the files received by System Management, as it is expected that System Management will perform data integrity checks internally before transferring.

OUTAGE_ID is a unique record specific to an associated EQUIP_ID. There are no restrictions on an Equipment item having more than one OUTAGE_ID associated with it. Accordingly, overlapping of two Outages for an Equipment item may occur and will be allowed, as SM will have ensured that the concurrent Outages are valid.

Files transferred containing records with existing OUTAGE_IDs will overwrite previously transferred values.

On rejection or cancellation of Outage by System Management, or cancellation of Outage by a Participant, the IMO will continue to retain the previously transferred information.

EQUIPMENT_OUTAGES (Data Elements)

XML Data Set Element Name	Description	Data Type	Constraints
OUTAGE_ID	Unique identifier of each Outage.	NUMBER(15,0)	UK, NN
EQUIP_ID	Unique identifier for the Equipment item.	NUMBER(15,0)	NN
EQUIP_NAME	Equipment Name	VARCHAR2(32)	NN
EQUIP_TYPE	Equipment Type: C – Circuit T – Transformer B – Circuit Breaker O – Other	CHAR(1)	NN

XML Data Set Element Name	Description	Data Type	Constraints
OUTAGE_REASON_FLAG	Outage Reason Flag. Values are: • P – Planned; • F – Forced;	CHAR(1)	NN
START_INTERVAL_PLANNED	Starting Interval of the Outage as Planned.	DATE (DD/MM/YYYY HH:MI)	NN
END_INTERVAL_PLANNED	End Interval of the Outage as Planned.	DATE (DD/MM/YYYY HH:MI)	NN
START_INTERVAL_ACTUAL	Actual Starting Interval of the Outage as recorded.	DATE (DD/MM/YYYY HH:MI)	
END_INTERVAL_ACTUAL	Actual End Interval of the Outage as recorded.	DATE (DD/MM/YYYY HH:MI)	
OUTAGE_TYPE	Details of Outage type: • F – Full • P – Partial	CHAR(1)	NN
OUTAGE_DESC	Outage Description	VARCHAR2(250)	
APPROVAL	A – Approved P – Accepted (Awaiting Approval) L – Lodged C – Cancelled	CHAR(1)	NN
APPROVAL_DATE	Date and time of SM approval status change.	DATE (DD/MM/YYYY HH:MI)	
OUTAGE_CONTINGENCY_PLAN	Outage Contingency Plan	VARCHAR2(250)	
CREATION_TIME	Record Creation Date. Timestamp when Outage request is logged by System Management	DATE (DD/MM/YYYY HH24:MI:SS)	NN
LAST_UPDATE_TIME	Last System Updated Date and Time as it was updated in SMITTS.	DATE (DD/MM/YYYY HH24:MI:SS)	NN

Agenda Item 5e: Updates to Commissioning Test Plans (PRC_2012_12)

1. BACKGROUND

The IMO, Griffin Energy and Verve Energy have recently identified similar issues relating to:

- Potential for Market Generators to be liable for civil penalties where an application for a Commissioning Test is made within the 20 Business Days notice period currently outlined in clause 3.21A.4 of the Market Rules; and

- Inability for a Market Participant to change the proposed Commissioning Test Period as approved in their Commissioning Test plan where an extension to the end date of a Commissioning Test Period is required.

To address these two issues the IMO has worked with Griffin Energy and Verve Energy to develop the Rule Change Proposal: Updates to Commissioning Test Plans (PRC_2012_12) for the consideration of the MAC.

In developing the proposed amendments the IMO has attempted to strike a balance between providing greater flexibility for Market Generators while enabling System Management to maintain some discretion around the approval of Commissioning Test Plans. The IMO notes that the changes proposed within PRC_2012_12 have significant impacts on System Management and so the IMO will work closely with System Management prior to the progression of the Rule Change Proposal to ensure that an appropriate outcome can be achieved.

In response to the IMO's proposed solution Griffin Energy has suggested that:

- shorter timeframes for the application for approval of Commissioning Test Plans under clause 3.21A.4 be considered. In particular Griffin Energy has suggested that 3 Trading Days should provide sufficient time before the start of the Commissioning Tests for System Management to consider an application. Note that the IMO has proposed a best endeavours requirement of 7 Trading Days prior to the Commissioning Test Period beginning; and

- System Management should only be able to apply its discretion under clause 3.21A.7(d) to reject an application if insufficient time has been provided to consider the application and the application was provided less than 7 Trading Days prior to the Commissioning Test Period beginning. Note that the IMO has proposed 20 Business Days apply under this clause (consistent with the current 20 Business Day requirement for applications for Commissioning Tests).

The IMO wishes to seek the views of the MAC, and in particular System Management around Griffin Energy's proposed alternative reduced timeframes.

2. RECOMMENDATIONS

It is recommended that the MAC:

- **Discuss** Griffin Energy's proposed reduced timeframes for the approval of Commissioning Test Plans;
- **Note** that the IMO will work with System Management to discuss the timing implications of the proposed changes prior to progressing the PRC_2012_12; and
- **Agree** for the IMO progress PRC_2012_12 through the formal rule change process, subject to any further agreed changes being incorporated into the proposal.

Wholesale Electricity Market
Pre Rule Change Proposal

Change Proposal No: PRC_2012_12
Received date: TBA

Change requested by:

Name:	Fiona Edmonds
Phone:	9254 4350
Fax:	9250 4399
Email:	fiona.edmonds@imowa.com.au
Organisation:	Independent Market Operator
Address:	Level 3 Governor Stirling Tower, 197 St Georges Terrace, Perth
Date submitted:	*TBA*
Urgency:	Medium – to be progressed via Standard Rule Change Process
Change Proposal title:	Updates to Commissioning Test Plans
Market Rule(s) affected:	3.21A.1, 3.21A.2, 3.21A.3, 3.21A.4, 3.21A.5, 3.21A.7, 3.21A.7A, 3.21A.8, 3.21A.9, 3.21A.10, 3.21A.11 3.21A.12, 3.21A.13, 3.21A.15, 3.21A.16 and the Glossary

Introduction

Market Rule 2.5.1 of the Wholesale Electricity Market Rules provides that any person (including the IMO) may make a Rule Change Proposal by completing a Rule Change Proposal Form that must be submitted to the Independent Market Operator.

This Change Proposal can be posted, faxed or emailed to:

Independent Market Operator
Attn: Group Manager, Market Development
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax: (08) 9254 4339
Email: market.development@imowa.com.au

The Independent Market Operator 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 electricity 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 Market Rule Change

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

Background

A Commissioning Test is a test of the ability of a generating system to operate at different levels of output reliably. Section 3.21A of the Wholesale Electricity Market (WEM) Rules (Market Rules) and the Power System Operation Procedure (PSOP): Commissioning and Testing outline the process by which Commissioning Tests are applied for, approved and conducted.

A Market Participant seeking to conduct a Commissioning Test must request permission from System Management, submitting the information as required by clause 3.21A.4 ("Commissioning Test plan") to System Management for the approval of such Commissioning Tests. This includes the name and location of the facility to be tested, the Commissioning Test Period and the details of the tests to be conducted, including an indicative test program. This request for a Commissioning Test must be submitted to System Management 20 Business Days in advance of the start date of the proposed tests[1].

[1] It should be noted that the Market Rules require that a Commissioning Test plan submitted to System Management must represent the "good faith" intention of the Market Participant to conduct the test (clause 3.21A.5).

Under the PSOP: Commissioning and Testing a level of flexibility is granted to Market Participants with respect to the timing for the request of a Commissioning Test plan and the details contained within each Commissioning Test Schedule(which are reflective of the indicative test plans)[2]:

- Step 2.1.3 notes that System Management may, at its discretion, consider a Commissioning Test plan submitted after the 20 Business Day timing requirement provided in the Market Rules, but must notify the IMO of a breach of the timing requirement if it approves such a Commissioning Test plan; and

- Step 2.4.2(b) allows Market Participants to request revisions to the Commissioning Test Schedules, initially provided through to System Management at the same time as its Commissioning Test plan (step 2.1.1), where they become aware of conditions which may prevent the Facility from conforming to the approved Commissioning Test plan. Requests for revisions of the Commissioning Test Schedules must be provided to System Management for approval as soon as practicable before the commencement of the Trading Day to which the Commissioning Test Schedule relates. This allows for flexibility with respect to the timing of on-the-day testing activities where possible, noting that in some instances System Management will potentially need to schedule additional Ancillary Services to cover the impacted Trading Intervals.

The IMO notes that clauses 3.21A.2, 3.21A.6, 3.21A.12 and 3.21A.13 of the Market Rules are civil penalty clauses under the Electricity Industry (Wholesale Electricity Market) Regulations 2004.

Issues

If System Management delays or cancels a Commissioning Test then the Market Participant is required under the clause 3.21A.4 of the Market Rules to submit an application for a new Commissioning Test with the associated 20 Business Day notice. In this same circumstance step 2.1.3 of the PSOP: Commissioning and Testing would allow the Market Participant to apply for the new Commissioning Test with less than the 20 Business Days notice, however System Management will be obliged to inform the IMO of a breach of the timing requirements and the participant will potentially be liable for the civil penalties associated with the timing breach.

Additionally a Market Participant requiring a change to the proposed Commissioning Test Period outlined in clause 3.21A.4(b) (start and end dates) will require an application for a new Commissioning Test (with the associated 20 Business Day notice as required under clause 3.21A.4). Scenarios which require a new Commissioning Test under the Amending Rules and PSOP: Commissioning and Testing include:

- An extension to the end date of a Commissioning Test Period; or

- A delay in the start date of a Commissioning Test Period would mean that the activities would occur beyond the dates of the original Commissioning Test Plan approved by System Management. Note that delays of activities within the Commissioning Test Period would be

[2] Commissioning Test Schedule is defined in the PSOP: Facility Outages and refers to the test to be conducted during a Trading Day as provided under clause 3.21A.4(c).

covered via the provision of updated Commissioning Test Schedules to System Management in accordance with the PSOP: Facility Outages.

The IMO considers that the current Market Rules are impractical due to their inflexibility in requiring a 20 Business Day application window for revisions to a Commissioning Test plan. At the extreme a Market Participant may be undertaking its final test on its Commissioning Test plan. This final test may indicate the need to undertake additional testing. However, the Market Participant would be unable to request an extension to the Commissioning Test Period and would have to either wait 20 Business Days for the approval of a new Commissioning Test or breach the timing requirement in the Market Rules and be subject to the potential application of civil penalties. In many instances it would be operationally and technically infeasible to apply for and wait the associated 20 Business Days to be able to complete the required tests. The potential delays as a result of this inflexibility or the application of civil penalties adds additional and unnecessary costs to commissioning process.

The IMO notes that the issues associated with this inflexibility have been raised with the IMO by both Verve Energy and Griffin Energy separately.

Additionally the IMO notes that the current version of the PSOP: Commissioning and Testing allows for closer to realtime changes to Commissioning Test plans than contemplated currently under the Market Rules.

Proposal

The IMO considers that a Market Participant should be able to request and System Management should be able to approve (if considered appropriate):

- A Commissioning Test plan within a shorter application period than currently provided for under the Market Rules (20 Business Days). This will ensure that where System Management cancels or delays a Commissioning Test under clause 3.21A. the Market Participant is not required to wait an additional 20 Business Days before undertaking the scheduled tests where an alternative appropriate time slot is available; and

- A revision to its original Commissioning Test plan to amend the applicable Commissioning Test Period or change the tests to be undertaken. This will ensure that closer to real time revisions to Commissioning Test plans can be approved where appropriate[3].

The IMO considers that obligations with respect to the timing of applications for Commissioning Tests should not be subject to civil penalties. As such, the IMO considers that the civil penalties relating to clause 3.21A.2 should more clearly relate to the requirement for a Market Participant to undertake commissioning activities in the market under an approved Commissioning Test. The IMO will work with the Public Utilities Office during the progression of this Rule Change Proposal to ensure the Regulations correctly reference this requirement.

[3] The IMO does not propose to change the late commissioning period after 1 October which is currently restricted to a period of 4 months commencing from the date and time of the first connection to the SWIS for testing purposes.

To allow for greater flexibility with respect to the application for approval of both new and revised Commissioning Test Plans and ensure that the civil penalty is not attached to the timing requirement for requesting a Commissioning Test, the IMO proposes to:

- Amend clause 3.21A.1 to clarify the definition of a Commissioning Test as referring to a series of activities to confirm the ability of a generating system to operate at different levels of output reliably. The IMO notes that this broader definition would be consistent with the wide range of activities that are often required to be undertaken for facilities undergoing commissioning.
- Amend clause 3.21A.2 to clearly refer to the requirement for Market Participants to undertake Commissioning Tests under an approved Commissioning Test Plan. This will ensure that civil penalties attached to this clause appropriately relate to only the requirement to commission under an approved Commissioning Test Plan and not the application timing requirements.
- Amend clause 3.21A.3 to refer to System Management's approval of a Commissioning Test Plan. The IMO notes that System Management must approve a Commissioning Test Plan (new or revised) not a Commissioning Test. This is consistent with the approval process outlined in the PSOP: Facility Outages. Changes to correctly refer to Commissioning Test and Commissioning Test Plan, where applicable have been proposed throughout section 3.21A of the Market Rules.
- Amend clause 3.21A.4 to shorten the Commissioning Test Plan application period to be 7 Trading Days before the start date of the proposed Commissioning Test. Note that this will be a best endeavours requirement which will take into account reduced timeframes where a revision to a Commissioning Test Plan is requested. The IMO notes that this does not preclude generators from applying and System Management from approving Commissioning Test Plans earlier and will provide significantly greater flexibility than under the current requirements of applying 20 Business Days in advance. Changes to reflect the amended definition under clause 3.21A.1 are also proposed *[Note that the IMO wishes to seek the views on the MAC and in particular System Management on whether shorter timeframes for application would be viable]*.
- Amend clause 3.21A.5 to improve the integrity of the clause.
- Amend clause 3.21A.7 to:
    - clarify that the information referred to in sub-clause (a) is that provided in the Commissioning Test Plan;
    - provide an ability for System Management to reject a Commissioning Test Plan which is received less than 20 Trading Days prior to the start of the proposed activities if it considers that it has inadequate time to consider the Commissioning Test Plan. Although Market Participants will be able to request approval of a Commissioning Test Plan up to 7 Trading Days in advance of the Commissioning Test Period and in the case of revisions to Commissioning Test Plans closer to real time, the IMO consider that System Management should maintain a discretion to reject a Commissioning Test Plan received less than 20 Trading Days prior to the start of the proposed activities in these circumstances. This will ensure that during Summer

months and around the start of the Capacity Year adequate time to consider approvals of Commissioning Tests is available *[Note that the IMO wishes to seek the views on the MAC and in particular System Management on whether shorter timeframes for application would be viable]*; and

- reflect the amended definition of Commissioning Test under clause 3.21A.1.

- Delete clause 3.21A.7A to remove this blank clause.
- Amend clause 3.21A.8 to clarify that System Management must not show bias in approving Commissioning Test.
- Amend clause 3.21A.9 to require System Management to inform the relevant Market Participant as to whether it approves its Commissioning Test Plan. System Management's decision will need to be made prior to the Commissioning Test files being sent to the IMO at 8:30AM on the Scheduling Day for the relevant Trading Days impacted by the Commissioning Test. This will provide Market Participants with certainty as to whether the commissioning activities will be going ahead at least 2 Trading Days before the start date of the proposed activities. This will allow both the impacted Market Participant and other Market Participants sufficient time to react according to the likely impacts on the energy market.
- Amend clause 3.21A.10 to require System Management and a Market Participant to use their best endeavours to agree to an alternative test time where System Management can not currently accommodate a proposed Commissioning Test Plan. Where an appropriate time is agreed between both parties System Management will be required to approve the revised Commissioning Test Plan that is reflective of this time.
- Amend clause 3.21A.11 to clarify that System Management may also cancel a Commissioning Test if it is concerned about Power System Security or Power System Reliability. The IMO has also proposed amendments to refer to significant maintenance rather than extended maintenance for consistency with clause 3.21A.2.
- Amend clause 3.21A.12 to clarify that a Market Participant must adhere to the most recently approved Commissioning Test Plan.
- Amend clause 3.21A.13 to clarify that where a Market Participant can not adhere to its most recently approved Commissioning Test Plan it must inform System Management and may request a revision to its Commissioning Test Plan.
- Amend clause 3.21A.15 to clarifying that the PSOP: Facility Outage will cover the approvals process for Commissioning Test Plans.
- Amend the definition of Commissioning Test Period to correctly refer to clause 3.21A.4(b).
- Include a definition of a Commissioning Test Plan into the Glossary of the Market Rules. Currently section 3.21A interchangeably refers to Commissioning Test and Commissioning Test plan.

The IMO has also included a number of minor and typographical amendments to ensure consistency in the language used in this section of the Market Rules and improve the overall integrity of the Market Rules.

2. Explain the reason for the degree of urgency:

The IMO proposes that this Rule Change Proposal be progressed via the Standard Rule Change Process.

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

3.21A Commissioning Tests

3.21A.1. A Commissioning Test ("Commissioning Test") is a ~~test of the~~ series of activities which confirm the ability of a generating system to operate at different levels of output reliably.

3.21A.2. A Market Participant ~~seeking to~~ conducting a Commissioning Test for a generating system that has undergone significant maintenance or for a new generating system that has yet to commence operation, must conduct ~~request permission for~~ such tests under an approved Commissioning Test Pplan ~~from System Management in accordance with clause 3.21A.4~~.

3.21A.3. System Management may approve a Commissioning Test Plan only for a new generating system that is yet to commence operation, or for an existing generating system that has undergone significant maintenance.

3.21A.4. A Market Participant requesting permission for a Commissioning Test~~s~~ must use best endeavours to submit to System Management its Commissioning Test Plan for approval at least 7 Trading Days in advance of the commencement of the Commissioning Test Period. A Commissioning Test Plan must contain the following information ~~at least 20 Business Days in advance of the start date of the proposed tests~~:

(a) the name and location of the facility to be tested;

(b) details of the proposed Commissioning Test Period, including start and end dates for the proposed tests; and

(c) details of the proposed Commissioning Test to be undertaken ~~tests to be conducted~~, including an indicative test program, fuel mix and trip risk of the facility to be tested.

3.21A.5. A Commissioning Test Plan ~~plans~~ submitted by a Market Participant must represent the good faith intention of the Market Participant to conduct ~~such~~ the Commissioning Test.

3.21A.6. Where a Market Participant no longer plans to conduct a Commissioning Test it must inform System Management as soon as practicable.

3.21A.7. System Management must ~~accept~~ approve a ~~request for a Commissioning Test~~ Commissioning Test Plan, unless:

(a) in its opinion inadequate information is provided in the ~~request~~ Commissioning Test Plan; or

(b) in its opinion the conduct of the ~~test~~ proposed activities to be undertaken at the proposed times would pose a threat to Power System Security or Power System Reliability; or

(c) in the case of a new generating system that is yet to commence operation, the proposed Commissioning Test Period is greater than four months~~.~~; or

(d) in its opinion inadequate time to properly consider the Commissioning Test Plan has been provided, where the request has been received less than 20 Trading Days in advance of the start date of the proposed Commissioning Test.

~~3.21A.7A. [Blank]~~

3.21A.8. System Management must not show bias towards a Market Participant in regard to ~~scheduling of~~ approving a Commissioning Test Plan~~s~~.

3.21A.9. System Management must notify a Market Participant as to whether ~~System Management~~ it has approved a Commissioning Test Plan ~~within~~ prior to 8:00 AM on the Scheduling Day for which the Commissioning Test Plan would apply. ~~10 Business Days of receiving the notification described in clause 3.21A.4.~~

3.21A.10. Where System Management notifies a Market Participant that:

(a) a Commissioning Test Plan has not been approved ~~it must~~ then:

i. System Management must provide an explanation for its decision;

ii. System Management and the Market Participant must use their best endeavours to agree to an alternative time for the relevant Commissioning Test; and

iii. where System Management and the Market Participant agree an alternative time under clause 3.21A.10(a)(ii), the Market Participant must, as soon as practicable, submit a revised Commissioning Test Plan which reflects the agreed alternative time to System Management and System Management must approve that revised Commissioning Test Plan.

(b) a Commissioning Test Plan has been approved then, subject to clause 3.21A.11, the Market Participant may proceed with that Commissioning Test.

3.21A.11. If, having approved a Commissioning Test Plan, System Management becomes aware that:

(a) the conduct of the ~~test~~ activities at the proposed time would pose a threat to Power System Security or Power System Reliability, or in the case of a Facility returning to service after ~~extended~~ undergoing significant maintenance the return to service has been delayed, then it may delay or cancel the commencement of the Commissioning Test; or

(b) the Commissioning Test is no longer required then it may ~~revoke~~ cancel its approval of the Commissioning Test Plan,

and must notify the Market Participant conducting the Commissioning Test of such delay or cancellation.

3.21A.12. In conducting a Commissioning Test a Market Participant must conform to the most recent Commissioning Test Plan ~~test plan~~ approved by System Management.

3.21A.13. If a Market Participant conducting a Commissioning Test cannot conform to the ~~Test Plan~~ most recent Commissioning Test Plan approved by System Management then it ~~must~~:

(a) must inform System Management as soon as practicable; and

(b) ~~obtain~~ may request System Management's approval ~~under this clause 3.21A.13A~~ for a ~~new~~ revised Commissioning Test Plan.

3.21A.14. [Blank]

3.21A.15. System Management must document the procedure it follows in scheduling and approving Commissioning Tests in the Power System Operation Procedure and System Management and Market Participants must follow that documented Market Procedure when planning and conducting Commissioning Tests.

3.21A.16. By 8.30~~am~~AM each day System Management must provide the IMO with the information submitted under clause 3.21A.4 for Commissioning Test Plans approved under clauses 3.21A.9, 3.21A.10A for the Trading Day following the current Scheduling Day.

Glossary

Commissioning Test Plan: The information submitted to System Management in accordance with clause 3.21A.4, which may be an original Commissioning Test Plan or revised Commissioning Test Plan, as applicable.

Commissioning Test Period: The proposed period during which Commissioning Tests will be conducted, as provided to System Management under clause ~~3.21A.3~~ 3.21A.4(b).

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

The IMO considers that the proposed reduced timeframe for applying for Commissioning Tests and introduction of an ability to request revisions to a previously approved Commissioning Test will allow greater flexibility both for Market Generators and System Management. By providing for greater flexibility to generators undertaking commissioning activities the IMO considers that any required tests will be able to be conducted in a more efficient manner (if System Management considers it appropriate and can schedule applicable Ancillary Services). System Management will also be provided with greater discretion as to when to approve a Commissioning Test. The IMO considers that the proposed changes will better Wholesale Market Objective (a).

The IMO considers the changes are consistent with the remaining Wholesale Market Objectives. Further the IMO does not consider that the changes to the timelines will impact on System Managements ability to schedule appropriate levels of Ancillary Services.

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

Costs:

- There will be internal process changes required for System Management and Market Generators, and potentially staffing implications associated with the change.
- There will be IT costs to both the IMO and System Management which will need to be identified during the rule change process.

Benefits:

- Greater flexibility for Market Generators seeking to undertake Commissioning Tests and for System Management in determining whether to approve a new or revised Commissioning Test within a shorter timeframe.
- Removal of inappropriate civil penalties associated with applications for Commissioning Tests lodged less than 20 Business Days prior to the start of the proposed tests.
- Removal of additional, unnecessary commissioning costs imposed on Market Generators as a result of delays to be able to complete commissioning activities.

Agenda Item 6a: Overview of Recent and Upcoming IMO and System Management Procedure Change Proposals

Legend:

Shaded	Shaded rows indicate procedure changes that have been completed since the last MAC meeting.
Unshaded	Unshaded rows are procedure changes still being progressed.
Red Text	Red text indicates any updates to information

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
IMO Procedure Change Proposals					
PC_2011_04	Prudential Requirements	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Include some minor and typographical amendments to improve the integrity of the Market Procedure; • Include amendments required as a result of the Pre Rule Change Proposal: Prudential Requirements (PRC_2011_09) and o RC_2010_36 Acceptable Credit Criteria; and o RC_2011_04 List of entities meeting Acceptable Credit Criteria	• The amended Market Procedure: Prudential Requirements was presented alongside the Pre Rule Change Proposal: Prudential Requirements (PRC_2011_09) at the December MAC. • The IMO extended the first submission period for RC_2011_09 until 24 August 2012 to allow sufficient time for the Working Group (and other interested parties) to	• To be discussed by IMO Procedures Working Group	TBC

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
			consider the amendments to the Market Procedure. The IMO considered this necessary as details contained within the revised Market Procedure as required to allow interested parties an ability to provide formal comment on the proposed amended methodology and processes to calculate Prudential Obligations (as contained in RC_2011_09 and the amended Market Procedure)		
PC_2012_02	New Market Procedure for Balancing Facility Requirements	This new Market Procedure proposes to: • Reflect the IMO's new format arising from its Market Procedure project; and • Specify the technical and communication criteria that a Balancing Facility, or a type of Balancing Facility, must meet.	• Commencement.	• This new Market Procedure commenced on 1 July 2012.	1 July 2012
PC_2012_03	New Market Procedure for Balancing Market Forecasts	This new Market Procedure proposes to: • Reflect the IMO's new format arising from its Market Procedure project; and • Describe the processes that will support the determination and publication of the Balancing Forecast by the IMO, including outlining the information requirements from System Management to enable the Forecast BMO and Balancing Forecast to be prepared.	• Commencement.	• This new Market Procedure commenced on 1 July 2012.	1 July 2012

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
PC_2012_04	New Market Procedure for IMS Interface	This new Market Procedure proposes to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10)	• Commencement.	• This new Market Procedure commenced on 1 July 2012.	1 July 2012
TBA	Undertaking the LT PASA and conducting a review of the Planning Criterion	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Include some minor and typographical amendments to improve the integrity of the Market Procedure, including re-ordering some sections; and • Include both reviews required under clause 4.5.15 of the Market Rules (Planning Criterion and forecasting processes).	• The IMO is currently updating the Market Procedure following the 2 February 2011 working group meeting.	• Updated procedure to be presented back to working group for further discussion.	TBA
TBA	Participant Registration and Deregistration	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Revise the Market Procedure to provide more details of the relevant processes, including restructuring the Market Procedure to better present the process; • Reflect the new MPR system; • Ensure consistency with the Amending Rules from the Rule Change Proposal: Change of Review Board Name (RC_2010_18)	• The IMO is currently revising the Market Procedure	• To be discussed by IMO Procedures Working Group	
TBA	Facility Registration, Deregistration and	The proposed updates are to: • Reflect the IMO's new format arising from its	• The IMO is currently revising the Market	• To be discussed by IMO Procedures	

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
	Transfer	Market Procedures project; • Reflect the new MPR system; • Revise the Market Procedure to provide more details of the relevant processes including: o restructuring the Market Procedure to better present the process; o providing further details of the consultation processes with System Management; o clarifying that there should not be any restriction on the ability to provide notifications in a manner outlined in the Market Procedure for Notifications and Communications; and o reflect the new processes for digital certificates • Ensure consistency with the Amending Rules from the following Rule Change Proposals; o Curtailable Loads and Demand Side Programmes (RC_2010_29); and o Change of Review Board Name (RC_2010_18), Including the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10)	Procedure	Working Group	
TBA	Settlement	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the Amending Rules	• The IMO is currently revising the Market Procedure	• To be discussed by IMO Procedures Working Group	

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
		from the following Rule Change Proposals: o Settlement in Default Situations (RC_2010_04) o Change of Review Board Name (RC_2010_18); o Minor and typo (RC_2010_26) o Settlement Cycle Timelines (RC_2010_19) o Acceptable Credit Criteria (RC_2010_36)			
TBA	Meter Data Submission	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Clarify that the Procedure is part of the Settlement Market Procedures; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• The IMO is currently revising the Market Procedure	• To be discussed by the IMO Procedures Working Group	
TBA	Capacity Credit Allocation	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Clarify that the Procedure is part of the Settlement Market Procedures; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• The IMO is currently revising the Market Procedure	• To be discussed by IMO Procedures Working Group	
TBA	Intermittent Load Refund	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with amendments to the	• The IMO is currently revising the Market Procedure	• To be discussed by IMO Procedures Working Group	

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
		Market Rules which have occurred since Market Start			
TBA	Loss Factors	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; and • Better clarify the processes in the Market Procedure. • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• The IMO is currently working with Western Power to clarify some discrepancies between the Market Rules and Market Procedure	• To be discussed by the IMO Procedures Working Group	
TBA	Certification of Reserve Capacity	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the Amending Rules under the following Rule Change Proposals: o Certification of Reserve Capacity (RC_2010_14); o Curtailable Loads and Demand Side Programmes (RC_2010_29), Including the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10)	• The IMO is currently completing an internal review of the revised Market Procedure which will be completed by Mid-July.	• To be discussed by IMO Procedures Working Group during July	
TBA	Individual Reserve Capacity Requirements	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• The IMO is currently revising the Market Procedure	• To be discussed by IMO Procedures Working Group	

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
TBA	Declaration of Bilateral Trades and the Reserve Capacity Auction	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the Amending Rules from the following Rule Change Proposals: o Curtailable Loads and Demand Side Programmes (RC_2010_29); o Removal of Network Control Services Expression of Interest and Tender Process from the Market Rules (RC_2010_11); and o Certification of Reserve Capacity (RC_2010_14).	• The IMO is currently revising the Market Procedure	• To be discussed by IMO Procedures Working Group	
TBA	Reserve Capacity Performance Monitoring	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the Amending Rules from the Rule Change Proposal: Reserve Capacity Performance Monitoring (RC_2009_19)	• The IMO is currently revising the Market Procedure	• To be discussed by IMO Procedures Working Group	
TBA	Treatment of Small Generators	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• The IMO is currently revising the Market Procedure	• To be discussed by IMO Procedures Working Group	
TBA	Reserve Capacity Testing	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project;	• The IMO is currently revising the Market Procedure	• To be discussed by IMO Procedures Working Group	

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
		• Reflect the new Temperature Dependence Curve • Ensure consistency with the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10)			
TBA	Maximum Reserve Capacity Price	The proposed updates are to ensure consistency with the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10).	• The IMO is currently completing an internal review of the revised Market Procedure which will be completed by Mid-July.	• To be discussed by IMO Procedures Working Group during July	
TBA	Information Confidentiality	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10) along with all other rule changes which have occurred since Market Start	• The IMO is currently revising the Market Procedure	• To be discussed by IMO Procedures Working Group	
PC_2012_05	IT Interface – System Overview and requirements	The proposed updates are to ensure consistency with the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10)	• This Procedure Change Proposal was published on 11 June 2012. The Consultation period is currently open.	• Consultation close	9 July 2012
System Management Procedure Change Proposals					
PPCL0021	Replaced PSOPs: Competitive Balancing and Load Following Market 1	The proposed updates are to: • Amend the Dispatch and Communications and Control Systems PSOP's to reflect the changes arising from RC_2011_10.	• Commencement	• This final replaced PSOP commenced on 1 July 2012.	1 July 2012

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
PPCL0022	Replaced PSOPs: Competitive Balancing and Load Following Market 2	The proposed updates are to: • Amend the Ancillary Services and Power System Security PSOP's to reflect the changes arising from RC_2011_10.	• Commencement	• This final replaced PSOP commenced on 1 July 2012.	1 July 2012
PPCL0023	Replaced PSOPs: Competitive Balancing and Load Following Market 3	The proposed updates are to: • Amend the Commissioning and Testing, Facility Outages and Monitoring and Reporting PSOP's to reflect the changes arising from RC_2011_10.	• Commencement	• This final replaced PSOP commenced on 1 July 2012.	1 July 2012

Agenda Item 7a: Working Group Overview

1. WORKING GROUP OVERVIEW

Working Group (WG)	Status	Date commenced	Date concluded	Latest meeting date	Next scheduled meeting date
Reserve Capacity 2007 WG	Closed	Feb 07	May 07	-	-
NTDL WG	Closed	Oct 07	Nov 07	-	-
Energy Limits WG	Closed	Dec 07	Jan 08	-	-
DSM WG	Closed	Jan 08	May 08	-	-
SRC WG	Closed	Jun 08	Sept 08	-	-
Reserve Capacity 2008/09 WG	Closed	Dec 08	Jan 09	-	-
Renewable Energy Generation WG	Closed	Mar 08	Nov 10	-	-
Maximum Reserve Capacity Price WG	Closed	May 10	Jun 11	-	-
System Management Procedures WG	Active	Jul 07	Ongoing	12/12/2011	TBA
IMO Procedures WG	Active	Dec 07	Ongoing	26/05/2011	TBA
Rules Development Implementation WG	Active	Aug 10	Ongoing	07/06/2012	09/08/2012
Reserve Capacity Mechanism WG	Active	Feb 12	Ongoing	29/05/2012	12/07/2012