Independent Market Operator

Market Advisory Committee

Agenda

Meeting No.	39
Location:	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Wednesday 8 June 2011
Time:	2.00 – 5.00pm

Item	Subject	Responsible	Time
1.	**WELCOME**	**Chair**	2 min
2.	**MEETING APOLOGIES / ATTENDANCE**	**Chair**	2 min
3.	**MINUTES OF PREVIOUS MEETING** (pg 3 of 81)	**Chair**	10 min
4.	**ACTIONS ARISING** (pg 14 of 81)	**Chair**	10 min
5.	**MARKET RULES**		
	a) Market Rule Change Overview (pg 16 of 81)	**IMO**	2 min
	b) PRC_2010_27: Ancillary Services Payment Equations (pg 20 of 81)	**IMO**	20 min
	c) PRC_2011_04: Australian Financial Entities Credit Rating (pg 58 of 81)	**IMO**	5 min
6.	**MARKET PROCEDURES**		
	a) Overview (pg 61 of 81)	**IMO**	5 min
7.	**WORKING GROUPS**		
	a) Overview and membership updates (pg 67 of 81)	**IMO**	2 min
	b) MRCPWG Update (pg 69 of 81)	**IMO**	10 min
	c) RDIWG Update (pg 71 of 81)	**IMO**	10 min

Item	Subject	Responsible	Time
8.	**ISSUES** (to note)		
	a) Prudential Requirements Issues Paper (pg 72 of 81)	**IMO**	2 min
9.	**CONCEPT PAPERS**		
	a) Curtailable Load Dispatch for Network Control Service (SM) (pg 78 of 81)	**IMO**	15 min
10.	**GENERAL BUSINESS**		
11.	**NEXT MEETING: 13 July 2011 (2.00 – 5.00pm)**		

Independent Market Operator

Market Advisory Committee

Minutes

Meeting No.	38
Location	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date	Wednesday 11 May 2011
Time	Commencing at 2.00 pm

Attendees	**Class**	**Comment**
Allan Dawson	Chair	
Troy Forward	Compulsory – IMO	
Stephen MacLean	Compulsory – Customer	2.10–3.25 pm
Ken Brown	Compulsory – System Management	
Andrew Everett	Compulsory – Generator	
Neil Gibbney	Compulsory – Network Operator	Proxy
Steve Gould	Discretionary – Customer	
Corey Dykstra	Discretionary – Customer	
Michael Zammit	Discretionary – Customer	
Peter Huxtable	Discretionary – Contestable Customer Representative	
Andrew Sutherland	Discretionary – Generator	
Ben Tan	Discretionary – Generator	2.10–3.25 pm
Wana Yang	Observer – ERA	
Paul Biggs	Small Use Customer Representative	
Nerea Ugarte	Minister's appointee	
Apologies	**Class**	**Comment**
Shane Cremin	Discretionary – Generator	
Peter Mattner	Compulsory – Network Operator	
Also in attendance	**From**	**Comment**
Jenny Laidlaw	IMO	Minutes
Brendan Clarke	System Management	Presenter
Matt Schultz	Energy Response	Observer
Pablo Campillos	EnerNOC	Observer
Alasdair Macdonald	IMO	Observer
Courtney Roberts	IMO	Observer
Zoe Davies	IMO	Observer
Greg Ruthven	IMO	Observer

Item	Subject	Action
1.	**WELCOME** The Chair opened the meeting at 2.00 pm and welcomed members to the 38th meeting of the Market Advisory Committee (MAC).	
2.	**MEETING APOLOGIES / ATTENDANCE** Apologies were received from: • Shane Cremin • Ben Tan (late) • Peter Mattner The following other attendees were noted: • Neil Gibbney (Proxy for Peter Mattner) • Brendan Clarke (Presenter) • Matt Schultz (Observer) • Pablo Campillos (Observer) • Alasdair Macdonald (Observer) • Courtney Roberts (Observer) • Zoe Davies (Observer) • Greg Ruthven (Observer)	
3.	**MINUTES OF PREVIOUS MEETING** The minutes of MAC Meeting No. 37, held on 13 April 2011, were circulated prior to the meeting. The following amendments were agreed. ***Page 12: Section 9: MEP: Balancing and Load Following Ancillary Services Markets*** • "Mr Dykstra considered that the proposal appeared to be the best option available to increase participation in balancing within the constraint of the current market design. Mr Dykstra agreed with Mr Brown that balancing will be an issue in the WEM, perhaps not this year but eventually. However, Mr Dykstra did not support the proposal, considering that the net benefits indicated in the Cost Benefit Assessment (CBA) were low and ~~not worth~~ may not outweigh the time, effort and risks involved. Mr Everett was supportive of the move to competitive balancing and the direction of the proposed design, but noted that that he was proceeding in good faith with regards to the detail~~ed design process~~, for example around timing and rebidding. Mr Everett noted that he had elaborated his concerns over the inclusion of Load Following Ancillary Services (LFAS) in the core proposal, considering that LFAS issues should not be allowed to put the balancing component of the proposal at risk." *Action Point: The IMO to amend the minutes of Meeting No. 37 to reflect the points raised by the MAC and publish on the website as final.*	**IMO**

Item	Subject	Action
4.	**ACTIONS ARISING** There were no outstanding action items.	
5a	**MARKET RULE CHANGE OVERVIEW** The MAC noted the Market Rule Change Overview.	
5b	**ANCILLARY SERVICES PAYMENT EQUATIONS [PRC_2010_27]** Mr Troy Forward noted that since the previous MAC meeting the IMO had reviewed and revised the Pre Rule Change Proposal: Ancillary Services Payment Equations (PRC_2010_27). The changes made include: • removal of the cost calculation components of the proposal; • separate allocation of Load Following Ancillary Services (LFAS) costs for Peak and Off-Peak periods, to allow for a more appropriate allocation of costs for solar facilities; and • new provisions to allow Intermittent Generators with a negligible impact on the Load Following requirement to seek an exemption from funding LFAS, similar to the existing exemption option available for Spinning Reserve costs. Mr Forward advised MAC members that the updated Pre Rule Change Proposal would probably be distributed to MAC members out of session for review, prior to its formal submission into the rule change process. In response to a question from Mr Andrew Everett, there was some discussion about the impact of PRC_2010_27 and the Market Evolution Program (MEP) proposal for a competitive LFAS market on Generator Trip Reserve payments. Mr Forward noted that the IMO was trying with PRC_2010_27 to treat LFAS cost allocation as a standalone issue, in order to facilitate its progress. Mr Everett noted that he thought that Generator Trip Reserve may have been overlooked in the MEP proposal. Mr Forward responded that it was understood that the MEP solution for Ancillary Services needed to be complete and consistent with this rule change.	
6a	**MARKET PROCEDURE CHANGE OVERVIEW** Mr Forward noted that the Market Procedure overview included in the papers for this meeting incorrectly showed the Next Step for the Reserve Capacity Security procedure as “awaiting further comments from members due 11 April 2011”. Mr Forward also noted that the IMO had identified some additional amendments that needed to be made to the Procedure Change Proposal: Registration of Demand Side Programmes and the association of Non-Dispatchable Loads (Transitional Arrangements). The IMO had issued a Public Notice to this effect on 27 April 2011. The IMO now proposed to issue an addendum to the Market Procedure and then	

Item	Subject	Action
	undertake an informal consultation process, to ensure that the necessary timelines are met while maintaining sufficient time for public review. The IMO will also reconvene the IMO Procedure Change and Development Working Group to discuss the revised Market Procedure. Mr Michael Zammit questioned the impact of the proposed approach on the timelines for the Rule Change Proposal: Curtailable Loads and Demand Side Programmes (RC_2010_29). Mr Forward responded that the proposed start of the transition period has moved from 1 June 2011 to 1 July 2011, but the main changes are still scheduled (subject to the decision of the IMO Board) to commence on 1 October 2011. Mr Forward explained that it would not be possible to register a Demand Side Facility until 1 October 2011 as it would not yet be a recognised Facility Class. However, the transitional procedure would allow participants to pre-register their Demand Side Programmes so that they would be ready for operation when the new Amending Rules commence on 1 October 2011. Mr Forward considered that a three month transition period starting 1 July 2011 should give participants sufficient time to pre-register their Demand Side Programmes and Associated Loads. The MAC noted the overview of recent and upcoming procedure changes.	
7a	**PLACEMENT OF CURTAILABLE/DISPATCHABLE LOADS IN THE DISPATCH MERIT ORDER [CP_2011_01]** Mr Brendan Clarke provided MAC members with a presentation on System Management's Concept Paper: Placement of Curtailable/ Dispatchable Loads in the Dispatch Merit Order (CP_2011_01). A copy of the presentation is available on the IMO's website. Mr Clarke submitted that there was a manifest error in the Market Rules in relation to the dispatch of Curtailable Loads. Clause 7.6 of the Market Rules specifies that, subject to various conditions, System Management should issue Dispatch Instructions in the following order: 1. Verve Energy non-liquid; 2. Independent Power Producer (IPP) non-liquid; 3. Verve Energy liquid; and 4. IPP liquid. Mr Clarke noted that Curtailable Loads and Dispatchable Loads cannot specify their fuel nominations (liquid or non-liquid), and so it is unclear whether they belong in the second group (IPP non-liquid) or the fourth group (IPP liquid). During the February 2011 Varanus Island incident System Management dispatched a large number of Curtailable Loads, considering them as belonging to the non-liquids group. However, some of these Loads may have actually used liquid fuel during their dispatch (i.e. in their backup generators). Further, Appendix 1 of the Market Rules, which specifies the Standing Data for Curtailable Loads, implies that these Facilities belong in the fourth group (IPP liquids), in that their pay-as-bid price for dispatch can be set to the Alternative Maximum STEM	

Item	Subject	Action
	Price. Mr Clarke considered that the two parts of the Market Rules (clause 7.6 and Appendix 1) are not aligned. Mr Zammit questioned why the issue had not been identified previously, noting that Curtailable Loads had been dispatched before (in 2007/08). Mr Ken Brown responded that in previous dispatches System Management had treated Curtailable Loads as belonging to the liquids group. Mr Brown also noted the restriction placed on System Management's use of Curtailable Loads under clause 7.7.4(c) of the Market Rules. There was some discussion about the relationship between clause 7.6 and Appendix 1. Mr Corey Dykstra considered that there was not necessarily an inconsistency between the two sections. Mr Clarke disagreed, reiterating System Management's view that an inconsistency was implied. The Chair considered that an inconsistency would only exist if a Curtailable Load was assumed to be in the IPP non-liquids group, noting that Mr Clarke had mentioned that some of these Loads may have been using liquids. Mr Clarke responded that System Management wanted to make the correct group for Curtailable Loads explicit in the Market Rules. Mr Zammit suggested that Curtailable Loads could be assigned to a fifth, separate group as their characteristics differed from those of generators. The Chair noted that under the proposed MEP balancing market the current Dispatch Merit Order structure would be replaced and that there would effectively be only one. Mr Clarke replied that System Management still wanted to resolve the issue as the market would go through another summer before a new balancing market was implemented. The Chair questioned which group System Management proposed for Curtailable Loads. Mr Clarke considered that it could be possible to require Curtailable Loads to nominate their fuel in the same manner as generators, but there was general agreement that this would be a very complicated approach. Mr Clarke noted that System Management sought the views of MAC members, but suggested that the IPP liquids group be chosen. Mr Clarke proposed that either System Management or the IMO submit a Rule Change Proposal in line with the agreed approach. Mr Stephen MacLean queried whether Mr Zammit's suggestion of a new, separate group for Curtailable Loads should be given further consideration. Mr Zammit again noted the differences between Curtailable Loads and other facility types, but considered that of the existing groups he would suggest the IPP liquids group. Mr Dykstra considered that it made sense to place Curtailable Loads into the IPP non-liquids group, to help avoid the use of Verve Energy liquids. Mr Dykstra did not see any conflict in this interpretation. Mr Brown disagreed, considering that there was a conflict in the commercial sense. Mr Dykstra noted that there was still an overriding rule limiting the use of	

Item	Subject	Action
	these facilities. Mr MacLean replied that the status quo still left System Management uncertain about the order in which it should dispatch facilities. There was some discussion about the information available to System Management in the Dispatch Merit Order. Mr Everett queried whether facilities should not simply be dispatched on merit. Mr Brown considered that System Management would always need to make a decision about maintaining the future availability of a Curtailable Load, but would need to make these decisions more often if the Loads were assigned to the non-liquids group. The Chair suggested that Curtailable Loads be assigned to the IPP liquids group, given that this would only be for one more summer. Mr Zammit questioned whether this would be the easier change. The Chair replied that this seemed to be the case based on Mr Brown's comments. Mr Forward questioned whether the clarification could be achieved through a Market Procedure rather than a rule change. Mr MacLean considered that since the problem was a conflict between two rules a procedure may not be able to provide the solution. The Chair considered it a reasonable assumption that based on price Curtailable Loads belonged in the IPP liquids group. The Chair considered that this was not so much a manifest error in the Market Rules but an omission, and that Appendix 1 offered clear guidance as to the appropriate interpretation. Mr Clarke proposed that System Management submit a Rule Change Proposal to clarify the allocation of Curtailable Loads to the IPP liquids group. There was some discussion about the wording of the proposed amendments. *Action Point: System Management to develop a Rule Change Proposal to clarify that for the purpose of issuing Dispatch Instructions System Management must consider Curtailable Loads to be facilities using liquid fuel.*	**System Mgmt**
7b	**PENETRATION OF DSM IN RESERVE CAPACITY PROCUREMENT [CP_2011_02]** Mr Brendan Clarke provided MAC members with a presentation on System Management's Concept Paper: Penetration of DSM in Reserve Capacity Procurement (CP_2011_02). A copy of the presentation is available on the IMO's website. Mr Clarke noted that the title of CP_2011_02 was incorrect in the meeting papers, and apologised to MAC members for any confusion resulting from the error. Mr Clarke explained System Management's issue was that the penetration of Demand Side Management (DSM) allowed in the SWIS leads to a heightened risk to System Security. In response to a question from Mr Pablo Campillos, Mr Clarke confirmed that this was because of the restricted nature of DSM. Mr Clarke noted that in the 2010 Statement of Opportunities (SOO) the	

Item	Subject	Action
	total capacity requirement for the 2012/13 Capacity Year was given as 5501 MW. The amount of allowable DSM under the IMO's interpretation of clause 4.5.12 of the Market Rules was 1404 MW, 26 percent of the total capacity requirement. The Chair queried whether these numbers were quoted in the 2010 SOO. Mr Brown confirmed that this was the case, adding that the problem was around the correct interpretation of clause 4.5.12. Mr Clarke noted that System Management disagreed with the IMO that clause 4.5.12 should relate to: • the use of 50 percent Probability of Exceedance (POE) load requirements; • the use of DSM to supply the reserve margin; or • the probabilistic criterion (0.002 percent Unserved Energy). Mr Brown noted that System Management needed to allow many outages over a Capacity Year while maintaining the reserve margin. This meant that DSM was not suitable to cover the reserve margin as it was only available for a short period each year. Mr Clarke noted that the reserves in question were usually supplied by synchronised generation or Interruptible Loads that could provide the rapid response required. There was some discussion about the use of the probabilistic criterion (0.002 percent Unserved Energy). Mr Greg Ruthven considered that both criteria mentioned under clause 4.5.9 needed to be considered. Mr Brown responded that the Unserved Energy criterion was not yet the deciding factor for capacity requirements in the SWIS. The Chair questioned whether the methodology for the calculations under clause 4.5.12 has changed. Mr Ruthven replied that the same methodology had been used for the previous two years. Mr Brown considered that no other power system would permit a level of DSM penetration greater that 10 percent. In response to a question from the Chair, Mr Ruthven advised that the IMO had held discussions with System Management about their concerns and had just finalised the appointment of a consultant to investigate the issue further. The Chair queried what System Management sought from the MAC in relation to the issue. Mr Clarke replied that System Management wished the MAC to note the issue and the IMO to further consider it prior to the preparation of the next SOO. Mr MacLean queried whether System Management could provide more detail on the level of DSM penetration allowed in other jurisdictions. Mr Clarke noted that PJM allowed a maximum penetration of seven percent. Mr Brown agreed to provide some additional information to MAC members. Mr Campillos considered that while the SWIS was relatively high in terms of actual penetration, care was required when comparing markets due to differences in how other systems forecasted their requirements. *Action Point: System Management to provide MAC members with additional information around the levels of Demand Side Management*	**System Mgmt**

Item	Subject	Action
	penetration allowed in other electricity markets. Mr Clarke clarified that the issue was not around a limit on DSM but on the minimum capacity that needed to be provided by generation. Mr Zammit noted that the discussion had been mainly about DSM, and questioned whether this would still be the case if there was faster acting DSM available that could help keep frequency. There was some discussion about the different services that loads might be able to provide to the market. Mr Brown reiterated that his problem was with the minimum generation requirement and not with the volume of DSM. Mr Zammit questioned what System Management would see as the appropriate minimum generation level. Mr Brown and Mr Clarke suggested a minimum of 5100 MW of generation. There was some discussion about the differences between the 10 percent POE and the 50 percent POE forecasts, and the potential impact of using one set of values over the other in the calculations under clause 4.5.12. The Chair considered that the discussion highlighted some issues that have already been raised, in that the limitation of DSM availability to 24 hours per year was unsustainable. The Chair noted that this issue had been referred to the IMO's current review of the Reserve Capacity Mechanism (RCM). The Chair noted that currently all DSM was nominating into the 24 hour availability class. By comparison, a peaking generator could expect to run for around 100 hours each year. Mr MacLean noted that the calculation of the Maximum Reserve Capacity Price assumed 176 operating hours per year for a peaker. It was agreed that the IMO and System Management should continue to work together to explore System Management's concerns before the publication of the 2011 SOO. *Action Point: The IMO to work with System Management to investigate System Management's concerns regarding the methodology used by the IMO for Availability Curve calculations under clause 4.5.12 of the Market Rules, prior to the publication of the 2011 Statement of Opportunities.*	**IMO System Mgmt**
8a	**WORKING GROUP OVERVIEW** The MAC noted the Working Group overview. Mr Forward noted the IMO's proposal for Mr Alasdair Macdonald to replace Mrs Jacinda Papps as the Chair of the IMO Procedure Change and Development Working Group and as an IMO representative on the System Management Procedure Change and Development Working Group. Mr Forward also noted that the MAC had received a request for Ms Wana Yang to replace Mr Chris Brown as the Economic Regulation Authority's representative on the Rules Development Implementation Working Group	

Item	Subject	Action
	(RDIWG). The MAC agreed to the proposed changes. *Action Point: The IMO to replace Mrs Jacinda Papps with Mr Alasdair Macdonald in the membership details contained in the ToR for both the IMO and System Management Procedure Change and Development Working Groups and update the website accordingly.* *Action Point: The IMO to update the IMO website to reflect the replacement of Mr Chris Brown with Ms Wana Yang as a member of the Rules Development Implementation Working Group.*	**IMO** **IMO**
8b	**MRCPWG UPDATE** Mr Ruthven noted that the Maximum Reserve Capacity Price Working Group (MRCPWG) update in the papers for today's meeting was issued prior to the 5 May 2011 meeting of the MRCPWG. Mr Ruthven noted that at this meeting the Working Group had agreed on the methodology for determination of the margin M and the cost escalation method, and had also agreed to request further analysis on some items. A further meeting of the Working Group was proposed for a date to be confirmed in June 2011. Mr Ruthven expected that a draft Procedure Change Proposal would be presented to the MAC at its July 2011 meeting. There was some discussion about the new Reserve Capacity Price and how it compared with the price in previous years. The Chair noted that the biggest change from the previous price was due to a significant reduction in transmission costs. Mr Campillos considered that there was likely to be a cyclical variation in these prices from year to year, and that the latest price was likely to be picking up on an old history of access offers that reflected a more unconstrained network. Mr Campillos suggested that the price may therefore increase again in the future. There was some discussion about the changing availability of transmission access and the likely impact on the capacity price over time. The Chair noted that it was typical for grids with excess capacity to eventually use it, and for participants to be charged a marginal cost until no more capacity is available and a sudden jump to deep connection costs results. This pattern was likely to be reflected in the MRCP. There was general agreement that MRCP costs were likely to show a cyclical pattern in future years. The MAC noted the MRCPWG update.	
9	**GENERAL BUSINESS** Mr Andrew Sutherland noted that he wished to raise his concerns about the Rule Change Proposal: Certification of Reserve Capacity (RC_2010_14) with MAC members. These concerns were also documented in ERM Power's submission to the IMO on the Rule Change	

Item	Subject	Action
	Proposal. Mr Sutherland noted his concern was with the proposed change to clause 4.11.1(a) to replace the expression “at daily peak demand times” with “for Peak Trading Intervals on Business Days”. In response to a question from Mr Brown, Mr Sutherland submitted that this change translated to a 14 hour fuel requirement for each Business Day. The Chair noted that the IMO Board has reached its decision and that the Final Rule Change Report for RC_2010_14 was due to be published the next day. Mr Sutherland replied that ERM Power would now need to consider their next steps. Mr Sutherland submitted that clause 4.11.1(a) had never been intended as a 14 hour daily fuel requirement, but had been introduced into the Certified Reserve Capacity Market Procedure. The IMO was now proposing an amendment to clause 4.11.1(a) to align it with the Market Procedure. Mr Sutherland did not recall any MAC discussion leading to an agreement to make this change. The Chair recalled an earlier MAC discussion on the possibility of reducing the requirement to 12 hours, but noted that System Management had opposed the idea, preferring a requirement of 14 hours or more. The Chair noted that the Market Procedures have the same standing in the market to the Market Rules. Mr Sutherland considered that there was nothing currently in the Market Rules about fuel requirements and that the decision appeared to have been to go down the path of the Market Procedure rather than that of the Market Rules. Mr MacLean questioned whether the IMO Board’s decision was now irreversible. Mr Sutherland considered that ERM Power may need to appeal the decision and that the decision was likely to have an adverse impact on future investment in new generation. The Chair noted that his understanding was that the proposed amendment was simply a clarification. Mr Sutherland noted that ERM Power had sought advice from ACIL Tasman on the impact of the Rule Change Proposal. ACIL Tasman had estimated in its report to ERM Power that the change could cost the state more than $390 million per annum in surplus fuel costs. Mr Ruthven responded that this estimate assumes incorrectly that the amendments are introducing a new fuel requirement. Mr Dykstra considered that as the Market Procedures are created in accordance with the Market Rules he would expect precedence to be given to the latter. Mr Dykstra considered that the two were not necessarily inconsistent, but there was a need to clarify the Market Rules. Mr Dykstra questioned whether the implications of clause 4.11.1 were fully understood. The Chair invited Mr Sutherland and Mr Derek McKay to meet with him to work through their concerns. Mr Sutherland questioned whether the decision on the proposal could be delayed. The Chair indicated that it may not be possible to delay the process at that stage.	

Item	Subject	Action
	Action Point: ERM Power to meet with the IMO to discuss its concerns around the Rule Change Proposal: Certification of Reserve Capacity (RC_2010_14).	**IMO**
11	**NEXT MEETING** Meeting No. 39 will be held on Wednesday 8 June 2011.	
CLOSED: The Chair declared the meeting closed at 3.25 pm.		

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Agenda item 4: 2010/11 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
24	2011	The IMO to amend the minutes of Meeting No. 37 to reflect the points raised by the MAC and publish on the website as final.	IMO	May	Completed.
25	2011	System Management to develop a Rule Change Proposal to clarify that for the purpose of issuing Dispatch Instructions System Management must consider Curtailable Loads to be facilities using liquid fuel.	System Management	May	
26	2011	System Management to provide MAC members with additional information around the levels of Demand Side Management penetration allowed in other electricity markets.	System Management	May	Completed

#	Year	Action	Responsibility	Meeting arising	Status/Progress
27	2011	The IMO to work with System Management to investigate System Management's concerns regarding the methodology used by the IMO for Availability Curve calculations under clause 4.5.12 of the Market Rules, prior to the publication of the 2011 Statement of Opportunities.	System Management	May	In progress
28	2011	The IMO to replace Mrs Jacinda Papps with Mr Alasdair Macdonald in the membership details contained in the ToR for both the IMO and System Management Procedure Change and Development Working Groups and update the website accordingly.	IMO	May	Completed.
29	2011	The IMO to update the IMO website to reflect the replacement of Mr Chris Brown with Ms Wana Yang as a member of the Rules Development Implementation Working Group.	IMO	May	Completed.
30	2011	ERM Power to meet with the IMO to discuss its concerns around the Rule Change Proposal: Certification of Reserve Capacity (RC_2010_14).	IMO	May	Completed

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)	1 June 2011
Fast track with Consultation Period open	0
Standard Rule Changes with 1st Submission Period Open	0
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)	6
Standard Rule Changes with 2nd Submission Period Open	0
Standard Rule Changes with 2nd Submission Period Closed (final report being prepared)	3
Rule Changes - Awaiting Minister's Approval and/or Commencement	4
Total Rule Changes Currently in Progress	**13**

Potential changes logged by the IMO- Not yet formally submitted	April	May
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)	22	22 (+0/-0)
Low Priority (may be submitted in the next 12/18 months)	20	20 (+0/-0)
Potential Rule Changes (H, M and L)	**42**	**42**
Minor and typographical (submitted in three batches per year)	40	41 (+1)
Total Potential Rule Changes	**82**	**83**

The changes in the rule change and issues log from April to May have arisen from:

Priority	Issue
High	N/a
Medium	**In:** • No issues have been added to the log this month. **Out:** • No issues have been progressed this month.
Low	**In:** • No issues have been added to the log this month. **Out:** • No issues have been progressed this month.

APPENDIX 1: FORMALLY SUBMITTED RULE CHANGES

Standard Rule Change with First Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2010_08	15/04/2010	Removal of DDAP uplift when less than facility minimum generation	Griffin Energy	Publish Draft Rule Change Report	19/09/2011
RC_2010_25	29/11/2010	Calculation of the Capacity Value of Intermittent Generation - Methodology 1 (IMO)	IMO	Publish Draft Rule Change Report	24/06/2011
RC_2010_28	01/03/2011	Capacity Credit Cancellation	IMO	Publish Draft Rule Change Report	28/06/2011
RC_2010_31	18/03/2011	De-registration of Rule Participants who no longer meet registration requirements	IMO	Publish Draft Rule Change Report	01/06/2011
RC_2010_37	30/11/2010	Calculation of the Capacity Value of Intermittent Generation - Methodology 2 (Griffin Energy)	Griffin Energy	Publish Draft Rule Change Report	24/06/2011
RC_2011_02	14/03/2011	Reassessment of Allowable Revenue during a Review Period	ERA	Publish Draft Rule Change Report	10/06/2011

Standard Rule Change with Second Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2010_12	17/11/2010	Required Level and Reserve Capacity Security	IMO	Publish Final Rule Change Report	22/07/2011
RC_2010_22	18/11/2010	Partial Commissioning of Intermittent Generators	IMO	Publish Final Rule Change Report	22/07/2011
RC_2010_29	02/02/2010	Curtailable Loads and Demand Side Programmes	IMO	Publish Final Rule Change Report	17/06/2011

Rule Changes Awaiting Commencement/Ministerial Approval

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2010_11	15/10/2010	Removal of Network Control Services Expression of Interest and Tender Process from the Market Rules	IMO	Commencement	01/07/2011
RC_2010_14	06/12/2010	Certification of Reserve Capacity	IMO	Ministerial Approval	10/06/2011
RC_2010_24	03/08/2010	Adjustment of Relevant Level for Intermittent Generation Capacity	Alinta	Commencement	01/07/2011
RC_2010_33	17/12/2010	Cost_LR	Verve Energy	Commencement	01/11/2011

Agenda Item 5b: Ancillary Services Payment Equations (PRC_2010_27)

1. BACKGROUND

At the March 2011 MAC meeting, the IMO presented a revised version of the Pre Rule Change Discussion Paper: Ancillary Services Payment Equations (PRC_2010_27). The original version of this paper, presented at the November 2010 MAC meeting, was prepared by ROAM Consulting and based on recommendations contained in its final report to the IMO for the Renewable Energy Generation Working Group[1] (REGWG) Work Package 3: Assessment of Frequency Control Service (FCS) and Technical Rules.

Since the March 2011 meeting the IMO has made a number of changes to the proposal, in response to the feedback provided by MAC members and further internal review. The changes include:

- removal of the proposed changes to the availability cost calculations for Load Following and Spinning Reserve[2];
- separate allocation of Load Following Ancillary Services (LFAS) costs for Peak and Off-Peak periods;
- new provisions to allow Intermittent Generators with a negligible impact on the Load Following requirement to seek an exemption from funding LFAS, similar to the existing exemption option available for Spinning Reserve costs; and
- simplification of the arrangements for the provision of the FKR (Frequency Keeping Requirement) and FKR_Loads (Frequency Keeping Requirement for Load fluctuations only) parameters used in the settlement calculations.

The revised proposal has undergone a technical review by ROAM Consulting to confirm that:

- the drafting accurately reflects the intention of the proposed changes, e.g. implements the Full Load, Marginal Generation cost allocation methodology for LFAS, separates the allocation of LFAS costs into Peak and Off-Peak periods and allows for an Intermittent Generator to be exempted from funding LFAS if its low volatility can be demonstrated;
- the prescribed calculations are algebraically valid; and
- all parameters referenced in the calculations have valid and logically consistent definitions.

An updated version of the Pre Rule Change Discussion Paper is attached.

[1] Additional background to the REGWG can be found at: http://www.imowa.com.au/REGWG

[2] Note that PRC_2010_27 proposes to replace the names “Load Following” and “Spinning Reserve” with “Frequency Keeping” and “Generator Trip Reserve” respectively.

2. CHANGES TO THE PRE RULE CHANGE DISCUSSION PAPER

Removal of the proposed changes to the availability cost calculations

The original paper proposed extensive changes to the way in which availability payments (made to Verve Energy for the provision of Load Following and Spinning Reserve Ancillary Services) are calculated. The changes included correction of manifest errors (such as the failure to correctly account for LFAS provided under Ancillary Services Contracts) and enhancements to more appropriately share the benefits of facilities providing both LFAS and Spinning Reserve Service concurrently.

However, since the presentation of this paper in November 2010 the Market Evolution Program (MEP) has developed a proposal for the implementation of a competitive market for balancing and LFAS. In April 2011 the IMO Board approved the progression of the MEP proposal, which has a target date for full implementation of April 2012.

The MEP proposal involves fundamental changes to the current procurement and pricing arrangements for LFAS, replacing the methodology on which the PRC_2010_27 amendments were based. The IMO does not consider it appropriate to continue with the cost calculation components of PRC_2010_27 at this time, as they will become inapplicable with the implementation of a competitive LFAS market. The IMO has therefore removed these components from the Pre Rule Change Discussion Paper.

The IMO notes that the concerns originally raised by ROAM Consulting about the availability cost calculations remain valid, and that it will need to ensure that the new balancing and LFAS market proposal addresses these concerns as well as the consequential impact of an LFAS market on Spinning Reserve cost calculations.

Separate allocation of LFAS costs for Peak and Off-Peak periods

The IMO has modified the proposed LFAS cost allocation methodology to:

- calculate a Market Participant's share of LFAS costs for each Trading Interval rather than over the Trading Month as a whole; and
- use separate FKR and FKR_Loads parameters for Peak and Off-Peak periods within each Trading Month, to allow for any future differences in requirements for these periods.

The changes have been made to allow for a more appropriate allocation of LFAS costs to facilities that either exhibit or can engineer different behaviour during Peak and Off-Peak Trading Intervals, and in particular to solar facilities.

Provision for an Intermittent Generator to seek exemption from funding LFAS

The IMO has proposed the inclusion of additional amendments to allow for Intermittent Generators with a negligible impact on the Load Following requirement (such as landfill gas facilities) to seek an exemption from funding LFAS. The proposed exemption is similar to the existing exemption option available for Spinning Reserve costs (section 2.30A of the Market Rules). The IMO considers that an exemption option is needed to prevent discrimination against renewable generators that are not "causers" of Load Following requirements and is the simplest way of dealing with this issue. (It seems neither practical nor feasible to design the cost allocation methodology itself in a way that avoids the need for the exemption.)

While the drafting of clause 2.30D.3 in the attached paper indicates the intent behind the process, the IMO proposes to engage the services of a suitable consultant to develop more rigorous criteria for exemptions. These criteria are likely to involve a measure of the short term volatility of a facility as a proportion of its size.

Provision of FKR and FKR_Loads parameters

The removal of the cost calculation components of PRC_2010_27 also removes the need to determine the GTR_Peak, GTR_Off-Peak and FKR parameters from Ancillary Services reports provided by System Management each Scheduling Day. Given this change the IMO has simplified the proposed arrangements for provision of the required FKR and FKR_Load parameters.

Under the revised proposal, System Management will provide the IMO with values for FKR_Peak, FKR_Off-Peak, FKR_Loads_Peak and FKR_Loads_Off-Peak for each Trading Month by the Interval Meter Deadline for that Trading Month. This methodology should minimise potential IT implementation costs, while ensuring that the parameters are determined on a consistent basis.

3. DECISIONS

The issues relating to the allocation of LFAS costs have now been discussed by the MAC several times, following the deliberations of the REGWG. Opinions continue to be divided on the merits of charging Intermittent Generators the additional Load Following costs they impose versus the merits of the current practice, where these additional costs are mainly borne by loads.

In the IMO's view further debate on these issues is unlikely to yield value. The IMO considers that charging LFAS costs to those causing the need for the services is the most efficient option and one that is most consistent with the Wholesale Market Objectives. On this basis, IMO management intends recommending this approach to the IMO Board and proceeding with a Rule Change Proposal that reflects this.

4. IMPACT OF THE MEP BALANCING AND LFAS PROPOSAL

Despite the removal of the cost calculation component of PRC_2010_27, there is still likely to be a significant rule drafting overlap between this proposal and the MEP proposal for a competitive balancing and LFAS market. This is because of the close interconnections between the clauses that determine LFAS costs (and so will be affected by the MEP proposal) and the clauses that allocate the costs of LFAS to its causers. For example, clause 9.9.2 deals with both the calculation and the allocation of LFAS costs.

However, despite this interconnection no conflict exists between the intent of the MEP proposal and that of the revised PRC_2010_27. The IMO notes that the drafting for the MEP proposal is being finalised and is due for publication in the near future. Once this drafting is available the IMO proposes to:

- review and update the drafting of PRC_2010_27, to ensure its alignment with the MEP LFAS proposal drafting and the refined exemption criteria; and
- formally submit the proposal into the rule change process.

The IMO will ensure that MAC members are given an opportunity to provide technical feedback on any drafting revisions prior to the submission of the Rule Change Proposal.

5. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Discuss** the amendments to the Ancillary Services Payment Equations Pre Rule Change Discussion Paper;
- **Note** the IMO's plan to progress PRC_2010_27 into the rule change process following consideration of the drafting for the new Load Following Ancillary Service market arrangements.

Wholesale Electricity Market
Pre Rule Change Discussion Paper

Change Proposal No: PRC_2010_27
Received date: TBA

Change requested by:

Name:	Allan Dawson
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Organisation:	Independent Market Operator
Address:	Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date submitted:	TBA
Urgency:	Standard Rule Change Process
Change Proposal title:	Ancillary Services Payment Equations
Market Rules affected:	2.30A, 2.30A.1, 2.30A.2, 2.30A.3, 2.30A.4, 2.30A.5, 2.30A.6, 2.30D (new), 2.30D.1 (new), 2.30D.2 (new), 2.30D.3 (new), 2.30D.4 (new), 2.30D.5 (new), 2.30D.6 (new), 2.30D.7 (new), 3.4.1, 3.9.1, 3.9.2, 3.9.3, 3.10.1, 3.10.1A (new), 3.10.2, 3.10.2A (new), 3.10.5, 3.11.4, 3.11.8, 3.11.8A, 3.11.8B, 3.13.1, 3.13.3B, 3.13.3C, 3.14.1, 3.14.2, 3.14.3, 3.18.11A, 3.22.1, 3.22.2, 3.22.3, 3.22.4 (new), 3.22.5 (new), 3.22.6 (new), 4.5.12, 6.17.6, 9.7.1, 9.9.1, 9.9.1A, 9.9.2, 9.9.2A (new), 9.9.3, 9.9.3A (new), 9.9.3B (new), 9.9.4, 10.5.1, the Glossary, Appendix 1 and Appendix 2.

Introduction

Clause 2.5.1 of the Wholesale Electricity Market Rules (Market Rules) provides that any person (including the Independent Market Operator (IMO)) may make a Rule Change Proposal by submitting a completed Rule Change Proposal form to the IMO.

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

Independent Market Operator
Attn: General Manager, Development
PO Box 7096
Cloisters Square, Perth, WA 6850

Fax: (08) 9254 4339
Email: market.development@imowa.com.au

The IMO will assess the proposal and, within five 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 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

Definition of Ancillary Services

The Market Rules identify the following as Ancillary Services in the Wholesale Electricity Market:

- Load Following Service (renamed Frequency Keeping Service in this proposal);
- Spinning Reserve Service (renamed Generator Trip Reserve Service in this proposal);
- Load Rejection Reserve Service;
- System Restart Service; and
- Dispatch Support Service.

This Rule Change Proposal addresses aspects of the first two services.

The Load Following (Frequency Keeping) requirement is described in the Market Rules (clause 3.10.1) as arising from:

- short term fluctuations in load;
- short term fluctuations in the output of Non-Scheduled Generators (mainly Intermittent Generators); and

- uninstructed output fluctuations from Scheduled Generators.

Analysis has indicated that the uninstructed output fluctuations from Scheduled Generators are likely to be small in comparison with Load and Intermittent Generator fluctuations.

The Spinning Reserve (Generator Trip Reserve) requirement is specified in the Market Rules (clause 3.10.2) to meet:

- generator trips; and
- expected maximum ramping up and ramping down of Loads over a 15 minute period.

The generator trip requirement dominates the specification for Spinning Reserve.

As a synchronised Scheduled Generator can meet the requirements for both Load Following Service and Spinning Reserve Service, these requirements are combined such that capacity providing Load Following is counted as also meeting the Spinning Reserve requirement (clause 3.10.2(b)). Currently, the Spinning Reserve requirement exceeds the Load Following requirement, and Interruptible Loads and slower-response thermal units are used to meet part of the Spinning Reserve requirement. These two supplies are not suitable for Load Following Service.

MAJOR ISSUES

Sharing of Frequency Keeping costs between Intermittent Generators and Loads

Under the existing Market Rules, the total cost of Frequency Keeping is recovered from Loads and Intermittent Generators in proportion to their energy consumed/sent out (defined in clause 3.14.1). Since system loads consume a much larger quantity of energy than Intermittent Generators produce, this means that the majority of the Frequency Keeping cost is borne by Loads. While the expected increased penetration of intermittent generation will increase the Frequency Keeping requirements and associated costs, Loads would bear most of these additional costs despite no change in their behaviour.

This Rule Change Proposal proposes that the “causer pays” principle should be applied and any incremental Frequency Keeping costs attributed to additional intermittent generation should be recovered from Intermittent Generators.

New clauses 3.22.4, 3.22.5 and 3.22.6 have been proposed that require System Management to report to the IMO both the Frequency Keeping requirement implemented for the preceding Trading Month and also its estimate of the Frequency Keeping requirement that it would have determined to address fluctuations in the load only (without Intermittent Generators or uninstructed fluctuations from Scheduled Generators). This differs from the existing Market Rules, where System Management’s annual forecast of the required Frequency Keeping Service is used in every month. Historically, variations in the Frequency Keeping requirements have been driven mainly by load growth and could be adjusted on an annual basis. However, with the entry of new large wind farms (e.g. Collgar) the Frequency Keeping requirement is expected to increase significantly. The proposed amendments allow for increases to occur only from the first month required, rather than for an entire year.

A "Full Load, Marginal Generation" approach[1] is then implemented in clause 3.14.1, such that Loads pay the full cost that would have been required in the absence of Intermittent Generators (and hence is attributable directly to Loads). Intermittent Generators then pay for the additional costs incurred (based on the difference between System Management's reported figures for the Frequency Keeping requirement with and without Intermittent Generators). Within each of the two groups (Loads and Intermittent Generators), the total absolute values of Metered Schedules are still used to determine the proportion of costs allocated to individual Facilities.

Differences between peak and off-peak intervals

The Frequency Keeping cost calculations have been divided into Peak and Off-Peak Trading Intervals. This has been done in response to concerns raised about the impact of the proposed cost allocation methodology on Intermittent Generators that either exhibit or can engineer different behaviour during Peak and Off-Peak periods (e.g. solar plant) when the costs of providing Ancillary Services may be higher or lower.

This approach requires System Management to report to the IMO both Peak and Off-Peak values for each of the Frequency Keeping requirements (whole system or loads only) reported under the new clause 3.22.4.

The proportion of Frequency Keeping Service costs allocated to each Market Participant under the "Full Load, Marginal Generation" methodology is proposed to be calculated for each Trading Interval, based on the consumption/generation for that Trading Interval and the Peak or Off-Peak Frequency Keeping requirement values as appropriate.

Exemptions from funding Frequency Keeping

There is a potential that some generators (both existing plant and new entrants) defined as Intermittent Generators under the Market Rules might not increase Frequency Keeping (due to low volatility in their output, for example) and so should not be charged a share of the Frequency Keeping costs.

A new clause (2.30D) is proposed to provide an exemption for Intermittent Generators from Frequency Keeping costs if those generators are deemed to have a negligible impact on Frequency Keeping requirements. This is analogous to the existing clause 2.30A that exempts generators with sufficiently slow maximum ramp down rates from funding Generator Trip Reserve costs.

The IMO proposes to undertake further analysis to develop rigorous criteria under which an Intermittent Generator could be eligible for an exemption. Such criteria would need to address new generators that do not yet have historical data and generators that do not have SCADA systems installed.

[1] ROAM Consulting report to the Independent Market Operator, "Assessment of FCS and Technical Rules", July 2010.

MINOR ISSUES

In addition to the issues described above, a number of naming convention changes and changes to address minor issues have been proposed.

Clause	Issue	Proposed solution
General	As the proportion of intermittent generation in the WEM increases, the Load Following Service will increasingly be related to the fluctuations in the output of Intermittent Generators (rather than fluctuations in the load). Referring to this service by the name "Load Following" is therefore misleading.	The name "Load Following" has been changed into "Frequency Keeping". This is also reflected in the terms used as abbreviations in equations, with the abbreviation "FKR" replacing the abbreviation "LF".
General	The standard for the Spinning Reserve Service is defined as being sufficient to cover generator trips, and also to cover the maximum load ramp expected over a period of 15 minutes. However, the Spinning Reserve requirement is dominated by the generator trip condition, and the maximum load ramp is very likely to be covered by the Load Following definition in the existing Market Rules (clause 3.10.1). Additionally, Loads do not contribute to the payment for the Spinning Reserve service (but do contribute to the payment for the Load Following Service).	The name "Spinning Reserve" has been changed into "Generator Trip Reserve". Clause 3.10.2 has been adjusted such that the Generator Trip Reserve Service covers only the Generator Trip Reserve Service, with the load ramping over 15 minutes being covered by the combination of the Load Following Service and the Spinning Reserve service (now covered in clause 3.10.2A).
General	**General terminology** - A number of terms are defined for use in equations by misleading names. For example: • Capacity_LF is the Capacity Cost of Load Following (rather than the capacity of Load Following required); • Reserve_Cost_Share refers specifically to the cost share of the Spinning Reserve Service (and does not include the Load Following Service).	• Capacity_LF has been changed to Capacity_Cost_FKR • Reserve_Cost_Share has been changed to GTR_Cost_Share • Reserve_Share has been changed to GTR_Share.
General	This proposal affects several clauses which will be amended by the Rule Change Proposal: Cost_LR (RC_2010_33)[2] when it commences on 1 November 2011. In addition, two new clauses (9.9.3A and 9.9.3B) have been proposed as part of RC_2010_33, which will require amendments to reflect the renaming of Load Following and Spinning Reserve to Frequency Keeping and Generator Trip	The proposed amendments incorporate the relevant changes from RC_2010_33. Comments have been used to indicate those amendments proposed under RC-2010_33.

[2] See: http://www.imowa.com.au/RC_2010_33

	Reserve.	
3.10.1	The relationship between the Minimum Frequency Keeping Capacity and the Load Following Requirement is unclear.	This has been made more explicit in clauses 3.10.1 and 3.10.1A.

2. Explain the reason for the degree of urgency:

It is proposed that this Rule Change Proposal be progressed through 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)

2.30A Exemption from Funding ~~Spinning~~ Generator Trip Reserve

2.30A.1. When registering an Intermittent Generator as a Non-Scheduled Generator, a Rule Participant, or an applicant for rule participation, may apply to the IMO for that Intermittent Generator to be exempted from funding ~~Spinning~~ Generator Trip Reserve costs.

2.30A.2. Where an application is received in accordance with clause 2.30A.1, the IMO must exempt the Intermittent Generator from funding ~~Spinning~~ Generator Trip Reserve costs where the applicant demonstrates to the satisfaction of the IMO that the shut down of the facility is a gradual process not exceeding a maximum ramp down rate equal to the installed capacity divided by 15MW/minute.

2.30A.3. The IMO must consult with System Management when assessing an application for exemption from funding ~~Spinning~~ Generator Trip Reserve costs.

2.30A.4. If the IMO approves the application for exempting an Intermittent Generator from funding ~~Spinning~~ Generator Trip Reserve costs then that facility must be excluded from the set of applicable facilities described in Appendix 2.

2.30A.5. Where the IMO considers, after consultation with System Management, that a change in the nature of an Intermittent Generator means that it should no longer be exempted from funding ~~Spinning~~ Generator Trip Reserve costs, it must:

(a) inform the relevant Market Participant of the first Trading Month from which the facility will cease to be exempted; and

(b) include that facility in the list of applicable facilities described in Appendix 2 from the commencement of that Trading Month.

2.30A.6. The IMO must document the ~~Spinning~~ Generator Trip Reserve costs exemption process in the Registration Procedure, and:

(a) applicants for exemption from ~~Spinning~~ Generator Trip Reserve costs must follow that documented Market Procedure; and

(b) the IMO and System Management must follow that documented Market Procedure when processing applications for exemption from ~~Spinning~~ Generator Trip Reserve cost funding.

The new section 2.30D allows for Intermittent Generators with minimal impact on Frequency Keeping requirements to be granted an exemption from funding Frequency Keeping costs.

2.30D Exemption from Funding Frequency Keeping

2.30D.1. When registering an Intermittent Generator as a Non-Scheduled Generator, a Rule Participant, or an applicant for rule participation, may apply to the IMO for that Intermittent Generator to be exempted from funding Frequency Keeping costs.

2.30D.2. A Market Participant may apply to the IMO for an Intermittent Generator registered to that Market Participant to be exempted from funding Frequency Keeping costs.

2.30D.3. Where an application is received in accordance with clause 2.30D.1 or 2.30D.2, the IMO must exempt the Intermittent Generator from funding Frequency Keeping costs where the applicant demonstrates to the satisfaction of the IMO that the technical characteristics of the Facility are such that the Facility will not materially add or contribute to the overall Frequency Keeping requirement.

2.30D.4. The IMO must consult with System Management when assessing an application for exemption from funding Frequency Keeping costs.

2.30D.5. If the IMO approves the application for exempting an Intermittent Generator from funding Frequency Keeping costs then that Facility must be exempted from funding Frequency Keeping costs effective from the start of the Trading Month in which the application was approved.

2.30D.6. Where the IMO considers, after consultation with System Management, that a change in the nature of an Intermittent Generator means that it should no longer be exempted from funding Frequency Keeping costs, it must:

(a) inform the relevant Market Participant of the first Trading Month from which the facility will cease to be exempted; and

(b) cease the exemption of that Facility under clause 2.30D.3 in the calculations under clause 3.14.1 effective from the commencement of that Trading Month.

2.30D.7. The IMO must document the Frequency Keeping costs exemption process in the Registration Procedure, and:

(a) applicants for exemption from Frequency Keeping costs must follow that documented Market Procedure; and

(b) the IMO and System Management must follow that documented Market Procedure when processing applications for exemption from Frequency Keeping cost funding.

3.4.1. The SWIS is in a High-risk Operating State when System Management considers that any of the following circumstances exist, or are likely to exist within the next fifteen minutes, or are likely to exist at a time beyond the next fifteen minutes; and actions other than those allowed under the Normal Operating State must be implemented immediately by System Management so as to moderate or avoid the circumstance:

(a) there is a violation of the ~~Spinning Reserve~~ Generator Trip Reserve and Frequency Keeping requirements determined in accordance with clause 3.11;

(b) insufficient ~~Load Following~~ Frequency Keeping range is available to meet the requirements determined in accordance with clause 3.11;

…

3.9.1. ~~Load Following~~ Frequency Keeping Service is the service of frequently adjusting:

(a) the output of one or more Scheduled Generators;

(b) the output of one or more Non-Scheduled Generators; or

(c) the consumption of one or more Loads

within a Trading Interval so as to match total system generation to total system load in real time in order to correct any SWIS frequency variations.

3.9.2. ~~Spinning~~ Generator Trip Reserve Service is the service of holding capacity associated with a synchronised Scheduled Generator, Dispatchable Load or Interruptible Load in reserve so that the relevant Facility is able to respond appropriately in any of the following situations:

(a) to retard frequency drops following the failure of one or more Registered Facilities; and

(b) in the case of ~~Spinning~~ Generator Trip Reserve Service provided by Scheduled Generators and Dispatchable Loads, to supply electricity if the alternative is to trigger involuntary load curtailment.

(c) [Blank]

3.9.3. ~~Spinning~~ Generator Trip Reserve response is measured over three time periods following a contingency event. A provider of ~~Spinning~~ Generator Trip Reserve Service must be able to ensure the relevant Facility can:

…

3.10.1. The standard for ~~Load Following~~ Frequency Keeping Service is a ~~level~~ MW capacity range which is sufficient to encompass:

(a) +30/-30 MW; and ~~provide Minimum Frequency Keeping Capacity, where the Minimum Frequency Keeping Capacity is the greater of:~~

~~i. 30 MW; and~~

~~ii. the capacity sufficient to cover 99.9% of the short term fluctuations in load and output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average.~~

(b) ~~[Blank]~~ the capacity sufficient to cover 99.9% of the short term fluctuations in load and output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average.

3.10.1A. The Minimum Frequency Keeping Capacity is the upper limit of the range defined in clause 3.10.1.

3.10.2. The standard for ~~Spinning~~ Generator Trip Reserve Service is a level which satisfies the following principles:

(a) the level must be sufficient to cover ~~the greater of~~:

i. 70% of the total output, including Parasitic Load, of the generation unit synchronised to the SWIS with the highest total output at that time; ~~and~~

ii. ~~the maximum load ramp expected over a period of 15 minutes;~~ [Blank]

(b) the level must include capacity utilised to meet the ~~Load Following~~ Frequency Keeping Service standard under clause 3.10.1, so that the capacity provided to meet the ~~Load Following~~ Frequency Keeping requirement is counted as providing part of the ~~Spinning~~ Generator Trip Reserve requirement;

(c) the level may be relaxed by up to 12% by System Management where it expects that the shortfall will be for a period of less than 30 minutes; and

(d) the level may be relaxed following activation of ~~Spinning Reserve~~ Generator Trip Reserve and may be relaxed by up to 100% if all reserves are exhausted and to maintain reserves would require involuntary load shedding. In such situations the levels must be fully restored as soon as practicable.

3.10.2A. The combined Generator Trip Reserve and Frequency Keeping requirement must be a level which is sufficient to cover the maximum load ramp expected over a period of 15 minutes.

3.10.5. The level of ~~Load Following~~ Frequency Keeping Service, ~~Spinning~~ Generator Trip Reserve Service and Load Rejection Reserve Service may be reduced:

(a) following relevant contingencies; or

(b) where System Management cannot meet the standard without shedding load, providing that System Management considers that reducing the level is not inconsistent with maintaining Power System Security.

3.11.4. System Management must determine the Ancillary Service Requirements in accordance with clause 3.11.1 and 3.11.5 for the:

(a) ~~Load Following~~ Frequency Keeping Service;

(b) ~~Spinning~~ Generator Trip Reserve Service;

(c) [Blank]

(d) Load Rejection Reserve Service;

(e) each Dispatch Support Service; and

(f) System Restart Service.

3.11.8. System Management may enter into an Ancillary Service Contract with a Rule Participant other than the Electricity Generation Corporation, for ~~Spinning~~ Generator Trip Reserve and ~~Load Following~~ Frequency Keeping Ancillary Services, where:

…

3.11.8A. System Management may enter into an Ancillary Service Contract with a Rule Participant for Load Rejection Reserve Service, System Restart Service and Dispatch Support Service~~Ancillary Services~~.

3.11.8B. System Management must obtain the approval of the Economic Regulation Authority before entering into an Ancillary Service Contract for Dispatch Support Service~~Ancillary Services~~.

3.13.1. The total payments by the IMO on behalf of System Management for Ancillary Services in accordance with Chapter 9 comprise:

(a) [Blank]

(aA) for ~~Load Following~~ Frequency Keeping Service for each Trading Month:

i. a capacity payment ~~Capacity_LF~~ Capacity_Cost_FKR calculated ~~as~~in accordance with clause 9.9.2A(b) for that Trading Month; and

~~1. the Monthly Reserve Capacity Price in that Trading Month;~~

~~2. multiplied by LFR, the capacity necessary to meet the Ancillary Service Requirement for Load Following in that month;~~

ii. an availability payment ~~Availiability_CostLF(m)~~ Availability_Cost_FKR calculated in accordance with clause 9.9.2(d) for that Trading Month;

(b) an amount ~~Availability_Cost_R(m)~~ Availability_Cost_GTR for ~~Spinning Reserve~~Generator Trip Reserve Service for each Trading Month, which is calculated in accordance with clause 9.9.2(c) for that Trading Month; and

(c) Cost_LRD, the monthly amount for Load Rejection Reserve Service and System Restart Service, determined in accordance with the process described in ~~clause~~ clauses 3.13.3B and 3.13.3C; and Dispatch Support Service~~service~~ determined in accordance with clause 3.11.8B.

3.13.3B. For each Review Period, by 31 March of the year in which the Review Period commences, the Economic Regulation Authority must determine values for Cost_LR, taking into account the Wholesale Market Objectives and in accordance with the following:

(a) by 30 November of the year prior to the start of the Review Period, System Management must submit a proposal for the Cost_LR parameter for the Review Period to the Economic Regulation Authority. Cost_LR must cover the costs for providing the Load Rejection Reserve Service and System Restart ~~Ancillary~~ Services and Dispatch Support ~~Ancillary~~ Services except those provided through clause 3.11.8B;

…

3.13.3C. For any year within a Review Period if System Management determines Cost_LR for the following ~~financial year~~ Financial Year to be materially different than the costs provided under clause 3.13.3B, then the Economic Regulation Authority must determine the revised values for Cost_LR, taking into account the Wholesale Market Objectives and in accordance with the following:

(a) by 30 November of the year prior to the start of the relevant ~~financial year~~Financial Year, System Management must submit an updated proposal for the Cost_LR parameter to the Economic Regulation Authority. Cost_LR must cover the costs for providing the Load Rejection Reserve Service and System Restart ~~Ancillary~~ Services and Dispatch Support ~~Ancillary~~ Services except those provided through clause 3.11.8B;

…

3.14.1. Market Participant p's share of the ~~Load Following~~ Frequency Keeping Service payment cost in each Trading ~~Month m~~ Interval t in a Trading Month m is ~~Load_Following_Share(p,m)~~ FKR_Share(p,t) which ~~equals~~ is given by:

FKR_Share(p,t) =

MS_Loads(p,t) / MS_Loads_Total(t) × FKR_Loads(m) / FKR(m)

+ MS_IG(p,t) / MS_IG_Total(t) × (FKR(m) - FKR_Loads(m)) / FKR(m)

Where:

MS_Loads(p,t) is the absolute value of the sum of the Metered Schedules for the Non-Dispatchable Loads, Interruptible Loads, and Curtailable Loads registered by the Market Participant p for Trading Interval t;

MS_Loads_Total(t) is the absolute value of the sum of the Metered Schedules for the Non-Dispatchable Loads, Interruptible Loads, and Curtailable Loads registered by all Market Participants for Trading Interval t;

MS_IG(p,t) is the sum of the Metered Schedules for Intermittent Generators registered by Market Participant p, except those Intermittent Generators exempted under clause 2.30D.3, for Trading Interval t;

MS_IG_Total(t) is the sum of the Metered Schedules for Intermittent Generators registered by all Market Participants, except those Intermittent Generators exempted under clause 2.30D.3, for Trading Interval t;

If Trading Interval t is a Peak Trading Interval, then FKR(m) is FKR_Peak(m), the maximum MW capacity requirement for Frequency Keeping Service during Peak Trading Intervals in Trading Month m as advised in accordance with clause 3.22.4(a);

If Trading Interval t is an Off-Peak Trading Interval, then FKR(m) is FKR_Off-Peak(m), the maximum MW capacity requirement for Frequency Keeping Service during Off-Peak Trading Intervals in Trading Month m as advised in accordance with clause 3.22.4(b);

If Trading Interval t is a Peak Trading Interval, then FKR_Loads(m) is FKR_Loads_Peak(m), the estimated maximum MW capacity requirement to cover short term fluctuations in load during Peak Trading Intervals in Trading Month m as advised in accordance with clause 3.22.4(c); and

If Trading Interval t is an Off-Peak Trading Interval, then FKR_Loads(m) is FKR_Loads_Off-Peak(m), the estimated maximum MW capacity requirement to cover short term fluctuations in load during Off-Peak Trading Intervals in Trading Month m as advised in accordance with clause 3.22.4(d).

~~(a) the Market Participant's contributing quantity; divided by~~

~~(b) the total contributing quantity of all Market Participants,~~

~~where a Market Participant's contributing quantity for Trading Month m is the sum of:~~

~~i. the absolute value of the sum of the Metered Schedules for the Non-Dispatchable Loads, Interruptible Loads, Curtailable Loads registered by the Market Participant for all Trading Intervals during Trading Month m; and~~

~~ii. the sum of the Metered Schedules for Non-Scheduled Generators registered by the Market Participant for all Trading Intervals during Trading Month m.~~

~~iii. [Blank]~~

3.14.2. Market Participant p's share of the ~~Spinning Reserve service~~ Generator Trip Reserve Service payment costs in each Trading Interval t is ~~Reserve_Share(p,t)~~ GTR_Share(p,t) which equals the amount determined in Appendix 2.

3.14.3. Market Participant p's share of the Load Rejection Reserve Service, System Restart Service and~~,~~ Dispatch Support Service~~services~~ payment costs in each Trading Month m is Consumption_Share(p,m) determined in accordance with clause 9.3.7.

3.18.11A. The Ready Reserve Standard requires that the available generation and demand-side capacity at any time satisfies the following principles:

(a) Subject to (c), the additional energy available within fifteen minutes must be sufficient to cover:

i. 30% of the total output, including Parasitic Load, of the generation unit synchronized to the SWIS with the highest total output at that time;

ii. plus the Minimum Frequency Keeping Capacity as defined in clause ~~3.10.1(a)~~3.10.1A.

(b) Subject to (c), and in addition to the additional energy described in (a), the additional energy available within four hours must be sufficient to cover:

i. 70% of the total output, including Parasitic Load, of the generation unit synchronized to the SWIS with the second highest total output at that time;

ii. less the Minimum Frequency Keeping Capacity as defined in clause ~~3.10.1(a)~~3.10.1A.

(c) …

3.22.1. The IMO must provide the following information to the Settlement System for each Trading Month:

(a) ~~Capacity_LF as described in clause 3.13.1(aA);~~[Blank]

(b) [Blank]

(c) Margin_Peak as described in clause 3.13.3A;

(d) Margin_Off-Peak as described in clause 3.13.3A;

(e) Capacity_R_Peak, the requirement for ~~Spinning Reserve~~ Generator Trip Reserve Service for Peak Trading Intervals assumed in forming Margin_Peak;

(f) Capacity_R_Off-Peak, the requirement for ~~Spinning Reserve~~ Generator Trip Reserve Service for Off-Peak Trading Intervals assumed in forming Margin_Off-Peak;

(fA) ~~LFR as described in clause 3.13.1(aA)(i)(2);~~[Blank]

(g) Cost_LRD as the sum of:

i. Cost_LR (as described in ~~clause~~ clauses 3.13.3B and 3.13.3C) divided by 12 as a monthly amount; and

ii. the monthly amount for Dispatch Support ~~service~~ Service as advised in accordance with clause 3.22.3(b); and

(h) the compensation due to changed outage plans to be paid to a Market Participant for that Trading Month as determined in accordance with clause 3.19.12(e).

The amendments to clause 3.22.2 are to ensure consistency with RC_2010_33 and to replace the names “Load Following” and “Spinning Reserve” with “Frequency Keeping” and “Generator Trip Reserve”.

3.22.2. When System Management has entered into an Ancillary Service Contract with a Rule Participant, System Management must as soon as practicable and not less than 20 Business Days prior to the Ancillary Service Contract taking effect, provide the IMO with:

(a) the identity of the Rule Participant~~,~~; and

(b) for each Contracted Ancillary Service ~~the Ancillary Service contracted~~ to be provided by the Rule Participant under the Ancillary Service Contract:~~;~~

i. a unique identifier for the Contracted Ancillary Service;

ii. the type of Ancillary Service where this can be one of:

1. Generator Trip Reserve Service;

2. Frequency Keeping Service;

3. Load Rejection Reserve Service;

4. System Restart Service; or

5. Dispatch Support Service; and

iii. the form of settlement data that System Management will provide to the IMO for the Contracted Ancillary Service provided by the Rule Participant, where this data must be one of the formats allowed by clause 3.22.3.

~~(c) a unique identifier for the Ancillary Service Contract;~~

~~(d) the form of settlement data that System Management will provide to the IMO for the Contracted Ancillary Service provided by the Rule Participant, where this data must be one of the formats allowed by clause 3.22.3.~~

The amendments to clause 3.22.3 are to ensure consistency with RC_2010_33 and to replace the names "Load Following" and "Spinning Reserve" with "Frequency Keeping" and "Generator Trip Reserve".

3.22.3. System Management must provide the following information to the IMO for each Rule Participant holding an Ancillary Service Contract for a Trading Month by the date specified in clause 9.16.2(a):

(a) the identity of the Rule Participant;

(b) for each Contracted Ancillary Service provided under an Ancillary Service Contract held by the Rule Participant:

i. the type of Ancillary Service where this can be one of:

1. ~~Spinning~~ Generator Trip Reserve Service;

2. ~~Load Following~~Frequency Keeping Service;

3. Load Rejection Reserve Service;

4. System Restart Service; or

5. Dispatch Support Service;

ii. for each Trading Interval of the Trading Month the quantity of Ancillary Service to a precision of 0.001 units ~~(where no specific unit of measure will be assumed).~~, where the unit of measure is:

1. MWh for Generator Trip Reserve Service;

2. MWh for Frequency Keeping Service;

3. MWh for Load Rejection Reserve Service;

4. as determined by System Management for System Restart Service; or

5. as determined by System Management for Dispatch Support Service; and

iii. either:

1. a total monthly payment for the Ancillary Service in dollars and whole cents; or

2. a price in dollars and whole cents per unit of the quantity described in (ii) per Trading Interval.

3.22.4. For each Trading Month, by the date specified in clause 9.16.2(a), System Management must provide to the IMO:

(a) FKR_Peak, the maximum MW capacity that was reserved by System Management for Frequency Keeping Service in Peak Trading Intervals during Trading Month m;

(b) FKR_Off-Peak, the maximum MW capacity that was reserved by System Management for Frequency Keeping Service in Off-Peak Trading Intervals during Trading Month m;

(c) FKR_Loads_Peak, System Management's estimate of the maximum MW capacity it would have determined to reserve for Frequency Keeping Service in Peak Trading Intervals during Trading Month m by considering short term fluctuations in load only, and excluding any short term fluctuations in output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators; and

(d) FKR_Loads_Off-Peak, System Management's estimate of the maximum MW capacity it would have determined to reserve for Frequency Keeping Service in Off-Peak Trading Intervals during Trading Month m by considering short term fluctuations in load only, and excluding any short term fluctuations in output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators.

3.22.5. System Management must document in the Power System Operation Procedure the procedure to be followed, and must follow that documented procedure, when determining FKR_Loads_Peak and FKR_Loads_Off-Peak in accordance with clause 3.22.4.

3.22.6. The IMO must publish the values of FKR_Peak, FKR_Off-Peak, FKR_Loads_Peak and FKR_Loads_Off-Peak provided by System Management under clause 3.22.4 on the Market Web Site as soon as practicable after the date specified in clause 9.16.2(a) for each Trading Month.

4.5.12. An Availability Curve for a Capacity Year is to contain the following information:

(a) the forecast capacity, in MW, required for more than 24 hours per year, 48 hours per year, 72 hours per year and 96 hours per year;

(b) the minimum capacity required to be provided by generation capacity if Power System Security and Power System Reliability is to be maintained. This minimum capacity is to be set at a level such that if:

i all Demand Side Management capacity (excluding Interruptible Load used to provide ~~Spinning~~ Generator Trip Reserve to the extent that it is anticipated to provide Certified Reserve Capacity), were activated during the Capacity Year so as to minimise the peak demand during that year; and

ii the Planning Criterion and the criteria for evaluating Outage Plans set out in clause 3.18.11 were to be applied to the load scenario defined by (i), then

it would be possible to satisfy the Planning Criterion and the criteria for evaluating Outage Plans set out in clause 3.18.11, as applied in paragraph (ii), using, to the extent that the capacity is anticipated to provide Certified Reserve Capacity, the anticipated installed generating capacity, the anticipated Interruptible Load capacity available as ~~Spinning~~ Generator Trip Reserve and, to the extent that further generation capacity would be required, an appropriate mix of generation capacity to make up that shortfall; and

…

6.17.6. The Dispatch Instruction Payment, DIP(p,d,t), for Market Participant p and Trading Interval t of Trading Day d equals the sum of:

…

(b) the sum over all Scheduled Generators and Dispatchable Loads registered by the Market Participant of the following amounts for Trading Interval t:

…

ii. if neither paragraph (i) nor (iA) applies, the amount for the Registered Facility is the product of:

…

2. the price defined as:

i. the contracted price, if the Dispatch Instruction is for the purposes of an Ancillary ~~Services~~ Service Contract for System Restart Service, Dispatch Support Service or Load Rejection Reserve Service;

ii. zero, if the Dispatch Instruction is for the purposes of an Ancillary ~~Services~~ Service Contract other than for System Restart Service, Dispatch Support Service or Load Rejection Reserve Service; or

iii. the applicable price as defined by clause 6.17.7 less MCAP for Trading Interval t.

…

9.7.1. The Reserve Capacity settlement amount for Market Participant p for Trading Month m is:

RCSA(p,m) =

Monthly Reserve Capacity Price(m) × (CC_NSPA(p,m)
– Sum(q∈ P,CC_ANSPA(p,q,m)))
+ Sum(a ∈ A, Monthly Special Price(p,m,a) × (CC_SPA(p,m,a)
– Sum(q∈ P,CC_ASPA(p,q,m,a))))
- Capacity Cost Refund(p,m)
- Intermittent Load Refund(p,m)
+ Supplementary Capacity Payment(p,m)
- Targeted Reserve Capacity Cost(m) × Shortfall Share(p,m)
- Shared Reserve Capacity Cost(m) × Capacity Share(p,m)
+ ~~Capacity_LF~~Capacity_Cost_FKR(m) × Capacity Share(p,m)

Where

...

~~Capacity_LF~~Capacity_Cost_FKR(m) is the total ~~Load Following service~~ Frequency Keeping Service capacity payment cost for Trading Month m as specified by the IMO under clause ~~3.22.1(a)~~9.9.2A(b).

The amendments to clause 9.9.1 are to ensure consistency with RC_2010_33, update the parameter names relating to Load Following and Spinning Reserve and reflect the allocation of Frequency Keeping Service costs to Market Participants on a per Trading Interval basis.

9.9.1. The Ancillary Service settlement amount for Market Participant p for Trading Month m is:

~~ASSA(p,m) = Electricity Generation Corporation AS Provider Payment(p,m)~~
~~+ d(p,i) × ASP_Payment(i,m)~~
~~- Load_Following_Share(p,m)~~
~~× (Capacity_LF(m) + Availability_Cost_LF(m))~~
~~- Reserve_Cost_Share(p,m)~~
~~- Consumption_Share(p,m) × Cost_LRD(m)~~

ASSA(p,m) = Electricity Generation Corporation AS Provider Payment(p,m)
+ ASP_Payment(p,m)
- FKR_Capacity_Cost_Share(p,m)
- FKR_Availability_Cost_Share(p,m)
- GTR_Cost_Share(p,m)
- Consumption_Share(p,m) × Cost_LRD(m)

Where:

the Electricity Generation Corporation AS Provider Payment(p,m) =
0 if Market Participant p is not the Electricity Generation Corporation and
(Availability_Cost_GTR(m) + Availability_Cost_FKR~~LF~~(m) +
Cost_LRD(m)) - ~~Sum(i∈I, ASP_Payment(i,m))~~
ASP_Balance_Payment(m) otherwise~~.~~;

~~d(p,i) is 1 if ASP i corresponds to Market Participant p and zero otherwise;~~

ASP_Payment(~~i~~p,m) is the total payment to Market Participant p for Contracted Ancillary Services in Trading Month m, determined in accordance with clause 9.9.3;

ASP_Balance_Payment(m) is the amount determined in accordance with clause 9.9.3A for Trading Month m;

~~Load_Following_Share(p,m) is the share of the Cost_LF(m) allocated to Market Participant p in Trading Month m, where this is to be determined by the IMO using the methodology described in clause 3.14.1;~~

~~Reserve_Cost_Share(p,m)~~ GTR_Cost_Share(p,m) is defined in clause 9.9.2(b);

FKR_Availability_Cost_Share(m) is defined in clause 9.9.2(bA);

FKR_Capacity_Cost_Share(m) is defined in clause 9.9.2A(a);

Consumption_Share(p,m) is the proportion of consumption associated with Market Participant p for Trading Month m determined by the IMO in accordance with clause 9.3.7;

~~Capacity_LF(m) is the total Load Following service payment cost for Trading Month m as specified by the IMO under clause 3.22.1(a);~~

~~Availability_Cost_R(m)~~ Availability_Cost_GTR(m) is the total ~~Spinning~~ Generator Trip Reserve Service availability payment cost~~s, excluding Load Following costs,~~ for Trading Month m, as calculated under clause 9.9.2(c);

~~Availability_Cost_LF(m)~~Availability_Cost_FKR(m) is the ~~Load Following~~ total Frequency Keeping Service availability payment cost~~s~~ for Trading Month m, as calculated under clause 9.9.2(d); and

Cost_LRD(m) is the total Load Rejection Reserve Service, System Restart Service~~,~~ and Dispatch Support Service ~~services~~ payment cost~~s~~ for Trading Month m as specified by the IMO under clause 3.22.1(g).

The amendments to clause 9.9.1A are to ensure consistency with RC_2010_33.

9.9.1A. The Ancillary Service settlement amount for Trading Month m for Rule Participant ~~k~~ i where Rule ~~Particant k~~ Participant i is not a Market Participant is ~~d(k,i) × ASP_Payment(i,m) where d(k,i) = 1 if ASP i corresponds to Rule Participant k and zero otherwise and ASP_Payment(i,m) is~~ ASP_Payment(i,m), determined in accordance with clause 9.9.3.

The amendments to clause 9.9.2 include changes to calculate allocate FKR availability costs on a per Trading Interval basis, ensure consistency with RC_2010_33 and reflect the new naming conventions.

9.9.2. The following terms ~~related~~ relate to Ancillary Service availability costs:

(a) ~~the total availability cost for Trading Month m:~~

~~Availability_Cost(m) =~~
~~0.5 × (Margin_Peak(m) × Sum(d∈D,t∈Peak,MCAP(d,t)~~
~~× (Capacity_R_Peak(m) – Sum(i∈I,ASP_SRQ(i,t)))))~~
~~+ 0.5 × (Margin_Off-Peak(m) × Sum(d∈D,t∈Off-Peak,MCAP(d,t)~~
~~× (Capacity_R_Off-Peak(m) – Sum(i∈I,ASP_SRQ(i,t)))))~~
~~+ Sum(i∈I,ASP_SRPayment(i,m))~~
~~+ Sum(i∈I,ASP_LFPayment(i,m))~~[Blank]

(b) the ~~Spinning Reserve Cost Share~~ Generator Trip Reserve cost share for Market Participant p~~, which is a Market Generator,~~ for Trading Month m:

~~Reserve_Cost_Share(p,m)~~GTR_Cost_Share(p,m) =
0.5 × (Margin_Peak(m) × Sum(~~d∈D,~~t∈Peak,MCAP(~~d,~~t)
× ~~Reserve_Share(p,t)~~ GTR_Share(p,t)
× (Capacity_R_Peak(m) – Sum(~~i∈I,ASP_SRQ(i,t)~~
c∈CAS_GTR,ASP_GTRQ(c,t)) - 0.5 ~~LFR(m)~~ × FKR_Peak(m))))
+ 0.5 × (Margin_Off-Peak(m) × Sum(~~d∈D,~~t∈Off-Peak,MCAP(~~d,~~t)
× ~~Reserve_Share(p,t)~~ GTR_Share(p,t)
× (Capacity_R_Off-Peak(m) – Sum(~~i∈I,ASP_SRQ(i,t)~~

c∈CAS_GTR,ASP_GTRQ(c,t))
- 0.5 × ~~LFR(m)~~FKR_Off-Peak(m))))
+ Sum(t∈~~Peak and Off_Peak~~T,~~ Reserve_Share(p,t)~~ GTR_Share(p,t)
× Sum(~~i∈I,ASP_SRPayment(i,m)~~
c∈CAS_GTR,ASP_GTRPayment(c,m)/ TITM))

(bA) the Frequency Keeping availability cost share for Market Participant p for Trading Month m:

FKR_Availability_Cost_Share(p,m) =
0.5 × (Margin_Peak(m) × 0.5 × FKR_Peak(m)
× Sum(t∈Peak,MCAP(t) × FKR_Share(p,t)))
+ 0.5 × (Margin_Off-Peak(m) × 0.5 × FKR_Off-Peak(m)
×Sum(t∈Off-Peak,MCAP(t) × FKR_Share(p,t)))
+ Sum(t∈T, FKR_Share(p,t)
× Sum(c∈CAS_FKR,ASP_FKRPayment(c,m) / TITM))

(c) the total ~~Spinning~~ Generator Trip Reserve ~~Availability Cost~~ availability cost for Trading Month m:

~~Availability_Cost_R(m) =~~
~~Sum(p∈P, Reserve_Cost_Share(p,m))~~

Availability_Cost_GTR(m) =
Sum(p∈P, GTR_Cost_Share(p,m))

(d) the total ~~Load Following Availability Cost~~ Frequency Keeping availability cost for Trading Month m:

~~Availability_Cost_LF(m) =~~
~~Availability_Cost(m) - Availability_Cost_R(m)~~

Availability_Cost_FKR(m) =
Sum(p∈P, FKR_Availability_Cost_Share(p,m))

Where

t denotes a Trading Interval in Trading Month m;

T is the set of Trading Intervals in Trading Month m;

c denotes a Contracted Ancillary Service;

CAS_GTR is the set of Contracted Generator Trip Reserve Services;

CAS_FKR is the set of Contracted Frequency Keeping Services;

P is the set of all Market Participants;

~~ASP_SRQ(i,t)~~ ASP_GTRQ(c,t) is the quantity provided by System Management in accordance with clause 3.22.3(b)(ii) for Contracted

Generator Trip Reserve Service c ~~of Spinning Reserve provided by Ancillary Service Provider i~~ in Trading Interval t multiplied by 2, to convert to units of MW ~~(this being one of the quantities referred to in clause 9.9.3)~~;

~~ASP_SRPayment(i,m)~~ASP_GTRPayment(c,m) is defined in clause ~~9.9.3~~9.9.4;

~~ASP_LFPayment(i,m)~~ ASP_FKRPayment(c,m) is defined in clause ~~9.9.3~~9.9.4;

TITM is the number of Trading Intervals in ~~the~~ Trading Month m (excluding any Trading Intervals prior to Energy Market Commencement);

FKR_Share(p,t) is the share of the Frequency Keeping Service payment costs allocated to Market Participant p in Trading Interval t, where this is to be determined by the IMO using the methodology described in clause 3.14.1;

~~Reserve_Share(p,t)~~ GTR_Share(p,t) is the share of the ~~Spinning~~ Generator Trip Reserve ~~service~~ Service payment costs allocated to Market Participant p in Trading Interval t, where this is to be determined by the IMO using the methodology described in clause 3.14.2;

Margin_Peak(m) is the reserve availability payment margin applying for Peak Trading Intervals for Trading Month m as specified by the IMO under clause 3.22.1(c);

Margin_Off-Peak(m) is the reserve availability payment margin applying for Off-Peak Trading Intervals for Trading Month m as specified by the IMO under clause 3.22.1(d);

Capacity_R_Peak(m) is the capacity necessary to cover the Ancillary Services Requirement for ~~Spinning~~ Generator Trip Reserve Service for Peak Trading Intervals for Trading Month m as specified by the IMO under clause 3.22.1(e);

Capacity_R_Off-Peak(m) is the capacity necessary to cover the Ancillary Services Requirement for ~~Spinning~~ Generator Trip Reserve Service for Off-Peak Trading Intervals for Trading Month m as specified by the IMO under clause 3.22.1(f);

~~LFR(m) is the capacity necessary to cover the Ancillary Services Requirement for Load Following for Trading Month m as specified by the IMO under clause 3.22.1(fA);~~

FKR_Peak(m) is the requirement for Frequency Keeping Service during Peak Trading Intervals in Trading Month m, as advised in accordance with clause 3.22.4(a);

FKR_Off-Peak(m) is the requirement for Frequency Keeping Service during Off-Peak Trading Intervals in Trading Month m, as advised in accordance with clause 3.22.4(b);

~~MCAP(d,t) has the meaning given in clause 9.8.1and=0 if MCAP (d,t)<0;~~MCAP(t) is the greater of zero and the Marginal Cost Administered Price for Trading Interval t calculated in accordance with clause 6.14.2;

Peak ~~denotes the set of Trading Intervals occurring during Peak Trading Intervals, where "t" refers to a Trading Interval during a Trading Day;~~ is the set of Peak Trading Intervals in Trading Month m; and

Off-Peak ~~denotes the set of Trading Intervals occurring during Off-Peak Trading Intervals, where "t" refers to a Trading Interval during a Trading Day; and~~ is the set of Off-Peak Trading Intervals in Trading Month m.

~~D denotes the set of Trading Days within Trading Month m, where "d" is used to refer to a member of that set;~~

The new clause 9.9.2A calculates the FKR capacity costs for a Trading Month for each Market Participant and in total.

9.9.2A. The following terms relate to Frequency Keeping Service capacity costs:

(a) the Frequency Keeping capacity cost share for Market Participant p for Trading Month m:

FKR_Capacity_Cost_Share(p,m) =
(Monthly_Reserve_Capacity_Price(m) / TITM) ×
((Sum(t∈Peak,FKR_Share(p,t)) × FKR_Peak(m))
+ (Sum(t∈Off-Peak,FKR_Share(p,t)) × FKR_Off-Peak(m)))

(b) the total Frequency Keeping capacity cost for Trading Month m:

Capacity_Cost_FKR(m) =
Sum(p∈P, FKR_Capacity_Cost_Share(p,m))

Where

t denotes a Trading Interval in Trading Month m;

P is the set of all Market Participants;

TITM is the number of Trading Intervals in Trading Month m (excluding any Trading Intervals prior to Energy Market Commencement);

Monthly_Reserve_Capacity_Price(m) is the Monthly Reserve Capacity Price which applies for Trading Month m, defined in accordance with clause 4.29.1;

FKR_Share(p,t) is the share of the Frequency Keeping Service payment costs allocated to Market Participant p in Trading Interval t, where this is to be determined by the IMO using the methodology described in clause 3.14.1;

FKR_Peak(m) is the requirement for Frequency Keeping Service during Peak Trading Intervals in Trading Month m, as advised in accordance with clause 3.22.4(a);

FKR_Off-Peak(m) is the requirement for Frequency Keeping Service during Off-Peak Trading Intervals in Trading Month m, as advised in accordance with clause 3.22.4(b);

Peak is the set of Peak Trading Intervals in Trading Month m; and

Off-Peak is the set of Off-Peak Trading Intervals in Trading Month m.

The amendments to clause 9.9.3 are to ensure consistency with RC_2010_33 and to update the names relating to Load Following and Spinning Reserve.

9.9.3. The value of ASP_Payment(i,m) for ~~Ancillary Service Provider~~ Rule Participant i in Trading Month m is the sum of:

(a) the sum over all ~~Ancillary Service Contracts for Spinning Reserve~~ Contracted Generator Trip Reserve Services c provided by Rule Participant i of ASP_GTRPayment(c,m)~~ASP_SRPayment(i,m), the payment under that contract~~;

(b) the sum over all ~~Ancillary Service Contracts for Load Following~~ Contracted Frequency Keeping Services c provided by Rule Participant i of ASP_FKRPayment(c,m)~~ASP_LFPayment(i,m), the payment under that contract~~;

(c) the sum over all ~~Ancillary Service Contracts for Load Rejection Reserve~~ Contracted Load Rejection Reserve Services c provided by Rule Participant i of ASP_LRPayment(~~i~~c,m)~~, the payment under that contract~~;

(d) the sum over all ~~Ancillary Service Contracts for System Restart~~ Contracted System Restart Services c provided by Rule Participant i of ASP_BSPayment(~~i~~c,m)~~, the payment under that contract~~; and

(e) the sum over all ~~Ancillary Service Contracts for Dispatch Support~~ Contracted Dispatch Support Services c provided by Rule Participant i of ASP_DSPayment(~~i~~c,m),~~ the payment under that contract~~

where each of the terms ~~ASP_SRPayment(i,m), ASP_LFPayment(i,m),~~ ASP_GTRPayment(c,m), ASP_FKRPayment(c,m), ASP_LRPayment(~~i~~c,m), ASP_BSPayment(~~i~~c,m) and ASP_DSPayment(~~i~~c,m) is determined in accordance with clause 9.9.4.

New clauses 9.9.3A and 9.9.3B are included to ensure consistency with RC_2010_33 – the names relating to Load Following and Spinning Reserve have been updated.

9.9.3A. The value of ASP_Balance_Payment(m) for Trading Month m is:

ASP_Balance_Payment(m) =

Sum(c∈CAS_GTR, ASP_GTRPayment(c,m)) +
Sum(c∈CAS_FKR, ASP_FKRPayment(c,m)) +
Min(Cost_LR(m), Sum(c∈CAS_LR, ASP_LRPayment(c,m))
+ Sum(c∈CAS_BS, ASP_BSPayment(c,m))), +
Sum(c∈CAS_DS, ASP_DSPayment(c,m))

where

c denotes a Contracted Ancillary Service;

CAS_GTR is the set of Contracted Generator Trip Reserve Services;

CAS_FKR is the set of Contracted Frequency Keeping Services;

CAS_LR is the set of Contracted Load Rejection Reserve Services;

CAS_BS is the set of Contracted System Restart Services;

CAS_DS is the set of Contracted Dispatch Support Services;

Cost_LR(m) is the amount specified by the IMO for Trading Month m under clause 3.22.1(g)(i) for Load Rejection Reserve Service and System Restart Service, and Dispatch Support Services except those provided through clause 3.11.8B, and

each of the terms ASP_GTRPayment(c,m), ASP_FKRPayment(c,m), ASP_LRPayment(c,m), ASP_BSPayment(c,m) and ASP_DSPayment(c,m) is determined in accordance with clause 9.9.4.

9.9.3B. The value of Cost_LR_Shortfall(m) for Trading Month m is:

Cost_LR_Shortfall(m) =

Max(0, Sum(c∈CAS_LR, ASP_LRPayment(c,m))
+ Sum(c∈CAS_BS, ASP_BSPayment(c,m))
- Cost_LR(m))

where

c denotes a Contracted Ancillary Service;

CAS_LR is the set of Contracted Load Rejection Reserve Services;

CAS_BS is the set of Contracted System Restart Services;

Cost_LR(m) is the amount specified by the IMO for Trading Month m under clause 3.22.1(g)(i) for Load Rejection Reserve Service and System Restart Service, and Dispatch Support Services except those provided through clause 3.11.8B, and

each of the terms ASP_LRPayment(c,m) and ASP_BSPayment(c,m) is determined in accordance with clause 9.9.4.

The amendments to clause 9.9.4 are to ensure consistency with RC_2010_33 and to update the names relating to Load Following and Spinning Reserve.

9.9.4. For each ~~Ancillary Service Provider i and each Ancillary Service Contract~~ Contracted Ancillary Service c, the payment~~s ASP_SRPayment(i,m), ASP_LFPayment(i,m),~~ ASP_GTRPayment(c,m) for Generator Trip Reserve Service, ASP_FKRPayment(c,m) for Frequency Keeping Service, ASP_LRPayment(~~i~~c,m) for Load Rejection Reserve Service, ASP_BSPayment(~~i~~c,m) for System Restart Service or ~~and~~ ASP_DSPayment(~~i~~c,m) for Dispatch Support Service, as applicable, ~~are~~ for Trading Month m is:

(a) the applicable monthly dollar value specified by System Management for that Trading Month in accordance with clause 3.22.3(b)(iii)(1); or~~, if no such value is specified,~~

(b) where no value is specified under clause 9.9.4(a), the product of the applicable price specified in clause 3.22.3(b)(iii)(2) for that Trading Month and the sum over Trading Intervals in that Trading Month of the applicable quantities specified in clause 3.22.3(b)(ii).

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:

…

(y) as soon as practicable after a Trading Interval:

i. the total generation in that Trading Interval;

ii. the total ~~Spinning~~ Generator Trip Reserve in that Trading Interval;

iii. an initial value of the Operational System Load Estimate, taken directly from System Management's EMS/SCADA system.

where these values are to be available from the IMO Web Site for each Trading Interval in the previous 12 calendar months;

(z) as soon as practicable after real-time:

i. the total generation;

ii. the total ~~Spinning~~ Generator Trip Reserve;

iii. an initial value of the Operational System Load Estimate, taken directly from System Management's EMS/SCADA system;

where these values are not required to be maintained on the IMO Web Site after their initial publication;

…

Glossary

Contracted Ancillary Service: An Ancillary Service provided by a Rule Participant under an Ancillary Service Contract.

Contracted Dispatch Support Service: A Dispatch Support Service provided by a Rule Participant under an Ancillary Service Contract.

Contracted Frequency Keeping Service: A Frequency Keeping Service provided by a Rule Participant under an Ancillary Service Contract.

Contracted Generator Trip Reserve Service: A Generator Trip Reserve Service provided by a Rule Participant under an Ancillary Service Contract.

Contracted Load Rejection Reserve Service: A Load Rejection Reserve Service provided by a Rule Participant under an Ancillary Service Contract.

Contracted System Restart Service: A System Restart Service provided by a Rule Participant under an Ancillary Service Contract.

Dispatch Support Service: Has the meaning given in clause 3.9.9.

Frequency Keeping: The frequent adjustment of the output of one or more generators or the consumption of one or more loads within a Trading Interval, so as to match total system generation to total system load in real time in order to correct any SWIS frequency variations.

Frequency Keeping Service: Has the meaning given in clause 3.9.1.

Generator Trip Reserve: Supply capacity held in reserve from synchronised Scheduled Generators, Dispatchable Loads or Interruptible Loads, so as to be available to support the system frequency in the event of an outage of a generating works or transmission equipment or to be dispatched to provide energy as allowed under these Market Rules.

Generator Trip Reserve Service: Has the meaning given in clause 3.9.2.

~~**Load Following Service**: Has the meaning given in clause 3.9.1.~~

Minimum Frequency Keeping Capacity: Has the meaning given in clause ~~3.10.1(a)~~3.10.1A.

~~**Spinning Reserve**: Supply capacity held in reserve from synchronised Scheduled Generators, Dispatchable Loads or Interruptible Loads, so as to be available to support the system frequency in the event of an outage of a generating works or transmission equipment or to be dispatched to provide energy as allowed under these Market Rules.~~

System Restart Service: ~~The Ancillary Service described~~Has the meaning given in clause 3.9.8.

Appendix 1: Standing Data

This Appendix describes the Standing Data to be maintained by the IMO for use by the IMO in market processes and by System Management in dispatch processes.

Standing Data required to be provided as a pre-condition for Facility Registration, and which is to be updated by Rule Participants as necessary, is described by clauses (a) to (j).

Standing Data not required to be provided as a pre-condition for Facility Registration but that which is required to be maintained by the IMO includes the data described in clauses (k) onwards.

…

(b) for a Scheduled Generator:

…

x. the capability to provide each of the following Ancillary Services, including information on trade-off functions when more than one other type of Ancillary Service and/or energy is provided simultaneously:

1. ~~Load Following~~Frequency Keeping Service;
2. ~~Spinning Reserve~~Generator Trip Reserve Service;
3. [Blank]; and
4. Load Rejection Reserve Service;

…

(g) for an Interruptible Load:

i. the Market Customer's nominated maximum consumption quantity, in units of MWh per Trading Interval;

ii. evidence that the communication and control systems required by clause 2.36 are in place and operational;

iii. real-time telemetry capabilities;

iv. the maximum amount of load that can be interrupted;

v. the maximum duration of any single interruption;

vi. the capability to provide each of the following Ancillary Services as a function of consumption:

1. ~~Spinning~~ Generator Trip Reserve Service~~.~~; and

1A. Frequency Keeping Service;

2. [Blank]

…

(i) for a Dispatchable Load:

…

x. the capability to provide each of the following Ancillary Services, including information on trade-off functions when more than one other type of Ancillary Service and/or energy is provided simultaneously:

1. ~~Load Following~~Frequency Keeping Service;

2. ~~Spinning Reserve~~Generator Trip Reserve Service;

3. [Blank]; and

4. Load Rejection Reserve Service;

…

(m) For each Intermittent Facility, whether it is exempted from funding ~~Spinning~~ Generator Trip Reserve costs.

Appendix 2: ~~Spinning~~ Generator Trip Reserve Cost Allocation

This Appendix determines the value of ~~Reserve_Share(p,t)~~ GTR_Share(p,t) of the ~~Spinning~~ Generator Trip Reserve ~~service~~ Service payment costs in Trading Interval t to be borne by Market Participant p.

In this Appendix the relevant Market Participant p is the Market Participant to whom a facility is registered, with the exception that in the case of unregistered generation systems serving Intermittent Loads, the relevant Market Participant p is the Market Participant to whom the Intermittent Load is registered.~~.~~

The calculations in this Appendix are based on data for a set of applicable facilities (indexed by f) where this set comprises all Scheduled Generators and all Non-Scheduled Generators registered during Trading Interval t, except those Intermittent Generators exempted under clause 2.30A.2. This set also includes all unregistered generation systems serving Intermittent Loads.

For the purpose of determining the ~~Reserve_Share(p,t)~~ GTR_Share(p,t) values, each applicable facility f has an applicable capacity associated with it for Trading Interval t.

- If facility f is an Intermittent Generator with an interval meter then this is double the MWh average interval meter reading for the Trading Month containing Trading Interval t.
- If facility f is a Scheduled Generator with an interval meter then this is double the MWh interval meter reading for Trading Interval t.
- If facility f is an Electricity Generation Corporation Intermittent Generator without an interval meter then this is double the average monthly MWh sent out generation of that facility based on SCADA data over the Trading Month containing Trading Interval t.
- If facility f is an Electricity Generation Corporation Scheduled Generator without an interval meter or an unmetered generation system serving Intermittent Load then this is double the MWh sent out generation of that facility based on SCADA data for Trading Interval t.

The methodology makes use of the data in Table 1.

Block Number	Block Range (MW)	Block Size (MW)
1	> 200	100
2	>125 and ≤ 200	75
3	>65 and ≤ 125	60
4	>45 and ≤ 65	20

5	>10 and ≤ 45	35

Table 1: Data ~~for~~ to Determine ~~Reserve_Share(p,t)~~GTR_Share(p,t)

For each Block, indicated by block number b, in Table 1, the Reserve Block Share is:

If Sum(f(i≤)) > 0

RBS(b) = [Block Size(b) / Sum(i, Block Size(i))] / Sum(f(i≤), TIS(f))

If Sum(f(i≤)) = 0

RBS(b) = 0

Where

Block Size(i) is the size of the Block with block number i listed in Table 1.

f(i≤) is the subset of applicable facilities that had applicable capacities for Trading Interval t lying within the block range of any Block with a block number value of b or less.

TIS(f) is 1 if the applicable facility f was synchronised to the SWIS during Trading Interval t, and is zero otherwise.

For each Block b in Table 1, the Reserve Generator Share is:

RGS(b) = Sum(i≥, RBS(i))

Where

i≥ is the set of Blocks listed in Table 1 that have a block number i greater than or equal to b.

For each Market Participant p, its unadjusted share of the ~~Spinning~~ Generator Trip Reserve ~~service~~ Service payment costs for the Trading Interval is:

USHARE(p) = Sum(f(p), RGS(b(f)) × TIS(f))

Where

f(p) is the set of applicable facilities for the Market Participant p that have applicable capacities within one of the block ranges listed in Table 1.

b(f) is the block number of the Block in Table 1 that has a block range that corresponds to the applicable capacity of the applicable facility f.

TIS(f) is 1 if the applicable facility f was synchronised to the SWIS during Trading Interval t, and is zero otherwise.

For each Market Participant p, its adjusted share of the ~~Spinning~~ Generator Trip Reserve ~~services~~ Service payment costs for Trading Interval t is:

~~Reserve_Share(p,t)~~ GTR_Share(p,t) = USHARE(p) / sum(q, USHARE(q))

Where

q is the index of the set of all Market Participants.

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

The IMO considers the changes proposed will have the following impact on the Wholesale Market Objectives:

Impact	Market Objectives
Allow the Market Rules to better address the objective.	a, c
Consistent with objective.	b, d, e
Inconsistent with objective.	

The proposed amendments will ensure a more accurate allocation of the costs of Load Following to those who cause them, through the adoption of the “Full Load, Marginal Generation” methodology for the allocation of Load Following Service costs. The IMO considers that these improvements better promote the economically efficient production and supply of electricity and electricity related services in the SWIS (Wholesale Market Objective (a)).

The IMO also considers that the more equitable allocation of Load Following Service costs on a “causer pays” basis will assist in avoiding discrimination against particular generator types, better promoting Wholesale Market Objective (c).

The IMO considers that the proposed amendments are consistent with the other Wholesale Market Objectives.

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

Costs:

- The IMO will have IT costs associated with this proposal. These costs will be quantified during the first submission period.
- The IMO will be required to update its internal operating procedures.
- The IMO may need to update some of its Market Procedures, including the Facility Registration, de-Registration and Facility Transfer Procedure, the Settlement Procedure, the Information Confidentiality Procedure and the Reserve Capacity Procedure for Undertaking the LT PASA and conducting a review of the Planning Criterion.
- System Management will need to update some of its Power System Operation Procedures, including the Ancillary Services Procedure, the Dispatch Procedure, the Security Procedure, the Operational Data Points for Generating Plant Procedure and the Glossary of Terms.

- System Management may incur additional costs around the provision of the parameters FKR_Peak, FKR_Off-Peak, FKR_Loads_Peak and FKR_Loads_Off-Peak each Trading Month. The IMO will work with System Management during the first submission period to quantify these costs.

Benefits:

- The Rule Change Proposal will provide more accurate pricing signals to generators and Loads that are more reflective of the actual costs of the Load Following Services that they require.
- The Rule Change Proposal will enhance the economic efficiency of the market, preventing investment in projects that may have large externalities that are not accounted for under the existing payment structure.

Wholesale Electricity Market
Pre-rule change discussion paper

Pre-rule change discussion paper No: *[PRC_2011_04]*
Received date: *[30 May 2011]*

Change requested by

Name:	Zoë Davies
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Fax:	
Email:	market.development@imowa.com.au
Organisation:	IMO
Address:	Level 3, Governor Stirling Tower, 197 St Georges Terrace
Date submitted:	30 May 2011
Urgency:	Medium
Change Proposal title:	Financial Entities not required to provide evidence they meet the Acceptable Credit Criteria
Market Rule(s) affected:	2.38.7 and new clauses 2.38.7 (a) and 2.38.7 (b)

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 Administration
> PO Box 7096
> Cloisters Square, Perth, WA 6850
>
> Fax: (08) 9254 4339
> Email: marketadmin@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 IMO commenced RC_2010_36 on 1 April 2011. The amendments effected by RC_2010_36 removed the requirements for a solicitor to sign an Acceptable Credit Criteria form for each Market Participant providing Credit Support or Reserve Capacity Security where the financial entity being used has been included on the List of entities that meet the Acceptable Credit Criteria published by the IMO[1]. The IMO considered that the proposed changes provided a more cost effective and efficient process than each Market Participant's solicitor signing the form.

Under clause 2.38.7 the IMO must maintain on the Market Web Site a list of entities which have provided the IMO, in the previous twelve months, with evidence satisfactory to the IMO that they meet the Acceptable Credit Criteria outlined in clause 2.38.6.

Proposal

In response to a suggestion from a Market Participant, the IMO has considered opportunities to further reduce the burden on Market Participants of providing evidence of the credit-worthiness of financial entities that provide guarantees or bank undertakings as either Credit Support or Reserve Capacity Security, where provision of that evidence is considered to be of little additional value.

It is proposed that, in addition to the provisions introduced by RC_2010_36, the four major Australian banks will be included on the List of entities (the List) maintained by the IMO, that

[1] Currently Market Participants providing Credit Support to the IMO do not have to provide a form where an entity is included on the list of acceptable credit providers. This is provided for under the Market Procedure for Prudential Requirements.

are not required to provide evidence that they meet the Acceptable Credit Criteria when a Market Participant puts forward a guarantee or bank undertaking as credit support or reserve capacity security from one of those entities.

Other financial entities may be included on the List by either the financial entity itself, or a Market Participant, providing the necessary evidence as to the credit-worthiness of the financial entity. This can be done either at 12-month intervals (to maintain the exemption) or as needed when a guarantee or bank undertaking is presented as credit support or reserve capacity security.

When a financial entity is removed from the list because the 12-month period expires, the relevant Market Participant will not necessarily be required to replace its security. The financial entity, or the Market Participant, will simply have to provide the usual evidence of creditworthiness when it next puts forward a guarantee to the IMO. The IMO maintains its monthly monitoring of the credit ratings of all financial entities providing reserve capacity security or credit support, regardless of whether they remain on the List.

However, Credit Support will cease to be valid if the entity that provided the guarantee or bank undertaking ceases to meet the Acceptable Credit Criteria. This includes if its credit rating falls below the level specified in clause 2.38.6. In that event, the Market Participant would be in default of its Prudential Obligations and be required to immediately notify the IMO and replace the guarantee or bank undertaking with one from an organisation that meets the Acceptable Credit Criteria, or with cash.

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2. Explain the reason for the degree of urgency:

The proposed rule changes are considered to be of a moderate level of urgency given that the issues with the existing rules prompting these changes do not put at risk the safe, effective and reliable operation of the WEM. The proposed rule changes cannot reasonably be considered to be of a high level of urgency for this reason.

---

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)

2.38.7 The IMO must maintain on the Market Web Site a list of entities which:

a) have provided the IMO, in the previous twelve months, with evidence satisfactory to the IMO that they meet the Acceptable Credit Criteria outlined in clause 2.38.6 or;

b) are one of the entities the IMO has determined are not required to provide evidence of meeting the Acceptable Credit Criteria outlined in clause 2.38.6

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

The proposed Market Rule change would allow the Market Rules to better address Wholesale Market Objectives:

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

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

by ensuring a more simple, efficient and cheaper way of certifying that an entity meets the Acceptable Credit Criteria.

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

Engaging a solicitor to complete the Acceptable Credit Criteria Form for an entity already deemed by the IMO as meeting the Acceptable Credit Criteria is expensive and time-consuming and the additional costs incurred are ultimately passed on to end consumers.

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.

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
IMO Procedure Change Proposals					
PC_2010_03	Monitoring Protocol	The proposed updates are to: • Allow the IMO to disclose the identity of System Management as a participant that notifies us of alleged breaches; and • Update to conform to recently adopted style changes.	• Final Report being prepared	• Final Report to be published	TBA
PC_2010_08	Supplementary Reserve Capacity (SRC)	The proposed new Market Procedure describes the process that the IMO and System Management will follow in: • acquiring Eligible Services, • entering into SRC Contracts; • determining the maximum contract value per hour of availability for any contract; and • Details the information that is required to	• Final Report being prepared	• Final Report to be published	TBA

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
		be exchanged. This Market Procedure needs to be published (as required by the Market Rules) and will be revised following any rule changes (if applicable).			
PC_2011_01	Procurement of Network Control Services	RC_2010_11[1] (Removal of NCS Expression of Interest and Tender Process from the Market Rules) removes the NCS expression of interest, tender and contracting processes from the Market Rules to allow a Network Operator to undertake these processes under the regulatory oversight of the Economic Regulation Authority. As this Rule Change Proposal removes the heads of power (and the requirement) for the Market Procedure the IMO proposes to revoke the Market Procedure in its entirety.	• Final Report being prepared	• Final Report to be published	13 June 2011
PC_2011_02	Data and IT Interface 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; • Remove the minimum workstation requirements, specifically outlining just the recommended workstation requirements; • Clarify the internet explorer requirements for different versions of the Market	• Final Report being prepared	• Final Report to be published	TBA

[1] Refer to www.imowa.com.au/RC_2010_11

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
		Participant Interface; and • Update the IMO's Access Security section.			
PC_2011_03	Registration of DSPs and the association of NDLs (Transitional Arrangements)	This is a new Market Procedure for Registration of Demand Side Programmes and the association of Non-Dispatchable Loads it is a transitional Market Procedure specifying the processes to the followed by the IMO and Market Customers between 1 June 2011 and 1 October 2011, for: • Registering a DSP; • Linking a CL to a DSP; • Associating an NDL to a DSP; and • Reassigning Capacity Credits from one DSP to one or more other DSPs.	• Final Report being prepared	• Final Report to be published	TBA
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 two Rule Change Proposals: o RC_2010_11[2] Removal of Network Control Services (NCS) Expression of Interest and Tender Process from the Market Rules;	• Presented at the 2 February 2011 working group meeting.	• Pending resolution of 'the big 4 banks' issue.	TBA

[2] Refer to www.imowa.com.au/RC_2010_11

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
		and o RC_2010_36[3] Acceptable Credit Criteria; The IMO would like to note that the remainder of the Market Procedure is out of scope for the purposes of this Procedure Change Proposal, as the IMO is currently undertaking a more detailed process review regarding Prudential requirements. Any amendments resulting from this review will be presented to the Working Group.			
TBD	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).	• Updating procedure as a result of 2 February 2011 working group meeting.	• Updated procedure to be presented at the working group meeting, to be scheduled.	TBD
TBD	Reserve Capacity Security	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedure project; • Reflect the broader heads of power for the Market Procedure; and • Ensure consistency with the proposed Amending Rules under the following Rule Change Proposals that the IMO is	• Presented at the 28 March 2011 working group meeting.	• Formal submissions into the Procedure process.	TBA

[3] Refer to www.imowa.com.au/RC_2010_36

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
		currently progressing: o Reserve Capacity Security (RC_2010_12); o Certification of Reserve Capacity (RC_2010_14); o Capacity Credit Cancellation (RC_2010_28); and o Acceptable Credit Criteria (RC_2010_36).			
System Management Procedure Change Proposals					
PPCL0016	Commissioning and Testing	The proposed update is to amend the procedure to reflect the commenced RC_2010_37 'Equipment Tests'.	• Submissions closed 13 January 2011. • Final Report being prepared by System Management	• Final Report to be provided to the IMO for approval	
PPCL0017	Facility Outages	The proposed update is to amend the procedure to reflect the commenced RC_2010_05 'Confidentiality of Accepted Outages by System Management'.	• Submissions closed 13 January 2011. • Final Report being prepared by System Management	• Final Report to be provided to the IMO for approval	
PPCL0018	Dispatch	The proposed updates are to allow for discretion to be exercised in requesting daily dispatch profiles from Market participants with facilities smaller than 30 MW.	• Submissions closed 8 April 2011. • Final Report being prepared by System Management	• Final Report to be provided to the IMO for approval	
PPCL0019	Monitoring and Reporting Protocol	The proposed updates are to provide further details around how System management will determine and review the annual Tolerance Range and any Facility Tolerance Ranges to apply for the purposes of clause 7.10.1 and 3.21 of the Market Rules.	• Submissions closed 8 April 2011. • Final Report being prepared by System Management	• Final Report to be provided to the IMO for approval	

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
		The proposed updates will ensure consistency with the requirements of RC_2009_22 and in particular the new clause 2.13.6K.			

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	-	-
System Management Procedures WG	Active	Jul 07	Ongoing	28/10/2010	TBA
IMO Procedures WG	Active	Dec 07	Ongoing	26/05/2011	TBA
Maximum Reserve Capacity Price WG	Active	May 10	Ongoing	05/05/2011	20/06/2011
Rules Development Implementation WG	Active	Aug 10	Ongoing	31/05/2011	21/06/2011

2. WORKING GROUP MEMBERSHIP UPDATES

In accordance with the Terms of Reference (ToR) the Market Advisory Committee (MAC) must approve the appointment and substitution of members for the:

- Rules Development Implementation Working Group

The MAC has received a request for Andrew Stevens to replace Shane Cremin as Griffin Energy's representative on the Rules Development Implementation Working Group.

The ToR does not specifically list the members, so an amended ToR is not required.

3. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Agree** with the proposed amendment to the membership of this Working Groups.

Agenda Item 7b: MRCPWG Update

1. RECENT PROGRESS

The Maximum Reserve Capacity Price Working Group (MRCPWG) last met on 5 May 2011. The next Working Group meeting is scheduled for 20 June 2011.

The independent report prepared by WorleyParsons regarding the development of margin M (covering legal, financing, approvals and other costs) and forward escalation factors was tabled at the last meeting. The report broadly agreed with the current methodology for determining margin M, and included a review on escalation factors and the options available to the Group in this regard. The group agreed to maintain the current methodology in respect of margin M and agreed that the use of a forward looking basis as recommended by SKM should be incorporated into the procedure, so long as it can be shown to be acceptable to regulators.

The inclusion of an allowance for Forced Outages was discussed at the meeting. It was agreed that the IMO would analyse the value of refunds paid, to assess the financial impact of forced outages on peaking gas turbine operators for discussion at the next meeting. It was noted that any changes in the MRCP in relation to Forced Outages could most likely only be implemented pending the outcome of further discussions on the capacity refund mechanism by the Rules Development & Implementation Working Group (RDIWG).

A sensitivity analysis was presented showing the impact on the MRCP of agreed and proposed changes to the MRCP, including the transmission cost calculation methodology, the change in the effective construction period in applying the WACC, the inclusion of annual asset insurance costs, the proposed change in DRP calculation methodology and the lengthening of the capitalisation period from 15 to 20 years.

The Group requested that the IMO perform a financial modelling exercise to ascertain the impact that a lengthening of the capitalisation period from 15 to 20 years would have on the cash flows of a model plant operator. The results of this exercise will be presented at the next meeting.

The next meeting scheduled for 20 June 2011 will consider:

- the impact of Forced Outages on operators of new peaking gas turbines;
- the impact of a lengthening of the capitalisation period from 15 to 20 years on cash flows within the first 10 years of plant operation;
- an updated draft Market Procedure, incorporating:
  - the revised Transmission Cost methodology that was broadly endorsed at the 24 March 2011 meeting;
  - instruction for the IMO to follow recent regulatory practice in the determination of the Debt Risk Premium;
  - an allowance within the Fixed O&M cost component for insurance to cover the replacement cost of the Facility;
  - alignment of the size of the land parcel with available lot sizes in each location; and

- the forward looking escalation methodology as per the methodology prepared by SKM and endorsed at the last meeting on 5 May 2011, subject to regulatory validity being confirmed.

The Working Group has been asked to submit comments on the draft Market procedure by 3 June 2011. This will allow the update of the draft Market Procedure for further discussion at the meeting on 20 June 2011. Following the review of the updated draft Market Procedure at the next meeting, the MRCPWG will consider the timing for the submission of the draft Market Procedure into the Procedure Change Process.

2. RECOMMENDATION

It is recommended that the MAC:

- **note** this update.

Agenda Item 7c: RDIWG Update

1. UPDATE

The Rules Development Implementation Working Group (RDIWG) last met on 30 May. At this meeting the following was discussed:

- Balancing market and load following ancillary service market – next steps including a revised set of Timelines and milestones for the MEP; and
- Two papers on next steps in relation to Reserve Capacity Refunds.

2. BALANCING AND LFAS MARKET NEXT STEPS

Following the approval by the IMO Board of the Balancing and Load Following Ancillary Service market arrangements, focus has turned to finalising outstanding design details and commencing rule drafting and system design work. The RDIWG agreed to receive a paper at its next meeting on 21 June on these outstanding design issues and to set aside time for a workshop after that to work through the detail with operational staff if need be. The RDIWG also agreed to hold two workshops on Tuesday 5 July and Tuesday 19 July to go through the draft rules before they are released for formal consultation. The IMO would like to extend an invitation to any MAC members who might want to attend one or both of these workshops.

3. RESERVE CAPACITY REFUNDS

The RDIWG was presented with a cover paper and more detailed paper from The Lantau Group on next steps in relation to reserve capacity refunds in light of the modelling work undertaken on the financial impacts of the proposed dynamic regime proposed and results emerging from the Reserve Capacity Review commissioned by the IMO Board. The former demonstrated a significantly lower level of refunds would have been paid over the last three years and the latter indicating that there is now more than sufficient capacity available in the market indicating some form of downward adjustment of future capacity prices was desirable. The IMO Board had considered the implications of this and had requested that the refund work be packaged up with any changes arising from the Reserve Capacity Review. RDIWG accepted the rationale behind this but asked that one of the refund proposals – namely the removal of the Net STEM shortfall refund obligation in favour of a compliance regime including the ability to impose an operational test. The IMO concurred with this.

Discussions on this subject led to questions around the current planned outage approval process – versus the treatment of forced outages – and after some discussion agreement was reached for the IMO to hold an informal workshop on the concerns and options around this after the next RDIWG meeting on June 21.

5. RECOMMENDATIONS

It is recommended that the MAC:

- **Note** this update.
- **Advise** the IMO whether they wish to attend the balancing and load following ancillary service rule drafting workshops on July 5 and July 19.

Independent Market Operator

Issues Paper

Title: **Prudential Requirements**

Ref: **IP_2011_01**

Date: **8 June 2011**

Contents

DOCUMENT DETAILS

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1. INTRODUCTION AND BACKGROUND

The purpose of this Issues Paper is to identify, for the benefit of the market, the issues identified with the Prudential Requirements Market Rules and Procedures, and to provide the MAC with background information relating to the work the IMO will commence to re-draft the Prudential Requirements Market Rules and Procedures as outlined in the proposal in this paper.

1.1. Background

The IMO manages the Prudential Requirements of Market Participants as set out in Chapter 2 of the Market Rules and the related Market Procedure: Prudential Requirements. Clauses 2.37 to 2.43 set out the manner in which the IMO is to set, monitor and increase Credit Limits and make calls on Market Participants to ensure the secure settlement of market transactions.

Specifically:

- Clause 2.37 sets out the process for determining, revising and reviewing the Credit Limit for each Market Participant.
- Clause 2.38 sets out the Acceptable Credit Criteria and provision of Credit Support to the IMO.
- Clause 2.39 sets out how a Trading Limit is calculated for each participant.
- Clause 2.40 sets out how an Outstanding Amount is to be calculated.
- Clause 2.41 sets out how a Trading Margin is calculated.
- Clause 2.42 sets out when and how a Margin Call for extra security may be made by the IMO.
- Clause 2.43 sets out the IMO's obligation to develop a Market Procedure dealing with the above provisions.

The Market Rules referring to Prudential Security are intended to provide for secure trading within the Wholesale Electricity Market (WEM) so that credit risk is not incorporated into the energy price. The benefit of ensuring adequate prudential security is maintained must be balanced against the cost of maintaining such security.

To a significant extent the prudential process is designed to ensure that, if a Market Participant defaults by failing to settle its STEM or Non-STEM invoice amounts on a due date, the IMO holds sufficient prudential security from the Market Participant in the form of a bank guarantee or cash so that the IMO would be able to settle the market without short-paying the market. Essentially, the prudential process is designed to protect the market from this risk.

The IMO must determine and monitor each Market Participant's Credit Limit and Trading Margin so that the IMO retains sufficient security to cover the range of potential defaults while not imposing excessive bank or interest costs on Market Participants.

The process that the IMO follows in fulfilling its obligations is set out in the relevant Market Procedure: Prudential Requirements, which has been operational since market start with only minor modifications made in 2008.

2. ISSUES

2.1. Issues in Detail

1) Clause 2.37 sets out the process for determining, revising and reviewing the Credit Limit for each Market Participant. Parts of this section are principles-based and others prescriptive leading to the IMO having to make decisions that affect Market Participants and the levels of security held while being unable to fully comply with the clause. A Market Participant cannot be sure that the level of its own credit limit is always appropriate, and that the credit limit set for other Participants is sufficient to protect the market. Market Participants are entitled to expect that the rules are being applied correctly, but this is not always possible if the methodology is vague. This causes uncertainty for Market Participants as to how security levels are set and revised and potentially exposes the market to unnecessary risk and/or cost.

2) The Market Rules do not explicitly recognise a need to have different mechanisms for establishing a Credit Limit for a new entrant and reviewing Credit Limits on an ongoing basis. The distinction should be made clear in the rules.

3) The Prudential Requirements as set out in the current Market Rules and Procedures are complex and difficult to apply in practice.

   a. Clause 2.37.4 requires the IMO to determine a Credit Limit that is equal to the maximum net amount that the participant is expected to owe the IMO over any 70 day period where this amount is not expected to be exceeded more than once in a 48 month period. The clause then continues and provides a number of other factors the IMO must “take into account”. If the IMO has determined a dollar amount 70-day liability which is the Credit Limit, it is not clear what the IMO is to do in practice when it takes into account the other factors.

   b. Clause 2.37.4 (d) requires the IMO to take into account the length of the settlement cycle and the process set out in clauses 9.23, 9.24 (default) and 2.32 (suspension and deregistration). This implies the IMO may be required to adjust Credit Limits to include financial cover to allow for the period from Market Participant default to de-registration. In practice, the IMO would seek to rely on alternative mechanisms such as the Supplier of Last Resort.

   c. Clause 2.37.4 (j) refers to any past breaches of the Regulations or Market Rules. It is not clear how the IMO could reasonably translate a Participant’s prior breaches into a dollar value to be used to adjust a Credit Limit.

   d. While the Market Procedure: Prudential Requirements adheres to an accepted methodology in setting and reviewing Credit Limits, the methodology could be simplified and clarified to better reflect the factors the IMO must “take into account” in determining Credit Limits as required by Clause 2.37.4. In addition, the Market Rule could be refined to clarify those matters which must be taken into account to ensure relevant and quantifiable issues are considered.

4) The changes currently being developed as part of the Market Evolution Project (MEP) intend to introduce a competitive balancing market that will change the dynamics of balancing liabilities in the WEM. The Market Rules and Procedures around Monitoring, Typical Accrual and Margin Call processes need to be better defined to enable the IMO

to properly manage changes to liabilities flowing from any changes to the balancing market.

5) An added risk with the current operating framework is that liabilities arising from capacity refunds due to Forced Outages, which can be material, are not easily calculated and outage data is only available to the IMO some days after the event. In the event of an extended outage this could mean the IMO cannot react quickly enough to ensure adequate security is held at all times. The changes to balancing stemming from the MEP are expected to improve the timeliness of outage data provision, and the Procedure could be improved by providing a clear process for the IMO to follow.

7) Clause 2.42 sets out when and how a Margin Call for extra security may be made by the IMO. This section contemplates the IMO calculating a Typical Accrual which is "the amount the IMO determines would have been the Outstanding Amount of the Market Participant" based on "average prices and quantities as applied in the most recent determination of the Market Participants' Credit Limit". In practice, in determining the anticipated Non-STEM liability component of a participant's Credit Limit, no such "average prices and quantities" are explicitly used, and therefore the proper calculation of a Typical Accrual and the application of the Margin Call rules is problematic.

8) The 2010 audit of the Rules and Procedures and the IMO's compliance with them noted there were no guidelines for assessing expected value of transactions in the Prudential Market procedure as required by MR 2.37.9 and 2.43.1.

9) Feedback from Market Participants indicates that they would prefer a clearer and simpler set of rules that are less complex and difficult to follow. The IMO also understands Market Participants' preferred situation would be more refined Market Rules and Procedures adjusted to govern and support the changing balancing provisions and to deliver greater clarity and certainty.

2.2. Current IMO Practice

For new Market Participants (Market Generators or Market Customers) the IMO receives certain base information from the prospective Market Participant and uses this data to calculate an anticipated 70-day exposure to the market.

For existing Market Participants and where sufficient data is available, the IMO establishes the Anticipated Maximum Exposure (AME) to the market over 70 consecutive days based on the previous four years of available data. Normally this occurs at the annual review of all Market Participants' Credit Limits as required by clause 2.37.3.

The Non-STEM component comprises the highest running 70-day total for balancing settlement for the Trading Day and each day's share of Ancillary Services payments, Market Fees, Reconciliation Settlement and Reserve Capacity payments. For participants participating in STEM the IMO also determines the maximum running 15-day exposure to the

STEM (plus GST). The Non-STEM exposure (70 days) and STEM exposure (15 days) are combined to deliver the AME which becomes the proposed revised Credit Limit.

The IMO has historically allowed Market Participants to make submissions to it as to whether the proposed revised Credit Limit should be adjusted up or down based on material changes to the participant's trading circumstances. For example, if a high AME is calculated that relates to a period that should no longer be considered a normal operating status such as during commissioning, or when significant market-wide events occurred that are rare such as the Varanus Island event in 2008. In such cases the IMO has sometimes adjusted its Credit Limit determination if sufficient objective evidence is available to support such a change. This is a sensible practice but does not appear in the Market Rules or Procedures.

2.3. Proposal

1) In order to improve, clarify and streamline the current Market Rules and Market Procedures, and to ensure the IMO has the capability to monitor changes to liability arising from the out-workings of the Market Evolution Project (MEP), the IMO recommends overhauling the Prudential Requirements Market Rule set and capturing the necessary detail in a revised Market Procedure.
2) The IMO proposes that new Rules will more explicitly capture relevant and appropriate concepts, differences between STEM and Non-STEM liabilities and allow for changes to the balancing provisions.
3) The IMO proposes that the Rules be redeveloped to capture the high level objectives and principles; that the new Rules largely retain the same concepts (Credit Limit, Credit Support, Trading Limits, Outstanding Amount, Trading Margin, Margin Call); and that the processes for setting, monitoring and revising Credit Limits be comprehensively detailed in a revised Market Procedure. This would allow for the Rules to be updated to reflect the experience gained during the first few years of Market operation, allow for any weaknesses and gaps in the Rules to be remedied and enable clarity and consistency to be built into the Procedures along with the flexibility to capture any changes flowing from MEP.

3. RECOMMENDATIONS

The IMO recommends that the Market Advisory Committee:

1. **Note** the issues listed above in relation to Prudential Requirements; and
2. **Note** that the IMO will undertake the required analysis and propose amendments to the Market Rules and Market Procedures.

Wholesale Electricity Market

Concept Paper Proposal Form

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

Concept requested by

Name:	Brendan Clarke
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Organisation:	*Western Power*
Address:	
Date submitted:	27 May 2011
Urgency:	*3-high*
Concept proposal title:	Curtailable Load Dispatch for Network Control Service
Market Rule(s) affected:	Clause 7.6.3 and Appendix 1

Introduction

The purpose of a Concept Paper is to foster analysis and discussion of complex issue(s) that can affect the Wholesale Electricity Market (Market), the Market Rules and the Wholesale Market Objectives.

The objectives of the market are:

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

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

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

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

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

This Concept Paper Proposal can be posted, faxed or emailed to:

Independent Market Operator
Attn: Manager Market Development
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General Information about Concept Paper Proposals

On receipt of this Concept Paper Proposal the Independent Market Operator (IMO) will proceed following these steps:

1. Log the proposal and notify the proposer that it has been received;
2. Assess the concept and consult with the Market Advisory Committee (MAC) for prioritisation against other Rule Participant issues registered; and
3. Work cooperatively with the proposer to develop the full concept paper including:
    - assessment against the Market Objectives; and
    - undertaking a detailed cost benefit analysis related to the identified options.

Details of the proposed Concept Paper

1. Identify the issue(s) with the existing Market and/or its Market Rules that are to be addressed by the proposed concept paper (including any examples):

Issue: The Market Rules limit the dispatch of Curtailable loads and so limits the effectiveness of alternate options to network investment in Network Control Service Contracts

System Management can issue dispatch instructions to Curtailable loads in accordance with rule

"7.6.10. Where a Market Participant has Capacity Credits granted in respect of a Curtailable Load:

(a) the IMO must provide System Management with the details of the Reserve Capacity Obligations to enable System Management to dispatch the Curtailable Load.

(b) System Management may issue directions to the Curtailable Load in accordance with the Reserve Capacity Obligations."

The Reserve Capacity Obligations are given in rule

"4.12.8. Where a Curtailable Load is dispatched to a level equal to its Reserve Capacity Obligation Quantity on two consecutive days the Reserve Capacity Obligation Quantity for the following day shall be zero."

In essence, even if a curtailable load is willing to be dispatched, System Management is restricted from issuing dispatch instructions for 3 or more consecutive days.

Western Power Networks needs to seek Demand Side or Local Generation options to displace Network Reinforcement. Network and Local Generation options are not normally restricted by consecutive day availability.

New network investment is required to maintain supply in the event of forced outage on an existing network component. If this should happen it may take several days to repair.

Thus the Network Control Service may need to be dispatched for multiple days. For example from Monday to Friday between 2 and 6pm whilst the load at the weak part of the network remains higher than the remaining network capability.

In addition there are instance due to voltage restrictions that may require multi day dispatch in anticipation of the failure of the network.

This makes Demand Side options less feasible as an alternative to a Network Reinforcement and less attractive than higher priced local generation options which do not have a multi day restriction.

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2. Outline the overall objective of the Concept Paper Proposal:

The overall objective of the concept paper is to highlight the restriction the current Market Rules place on the use of Demand Side options for Network Control Services.

3. Identify any reasonably practicable options for achieving the objective:

System Management believes that MAC should:

1. Note and discuss the issue of Demand Side Management dispatch for Network Control Services

2. Request a rule change be prepared and submitted to allow System Management to dispatch Curtailable Loads in accordance with their Network Control Service Contracts without restriction.

This issue will come to the fore shortly as the first of the Network Control Service Tenders are scheduled for release within the next few months.