Market Advisory Committee

Agenda

Meeting No.	66
Location:	IMO Board Room Level 17, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Wednesday 13th November 2013
Time:	2.00pm – 5.00pm

Item	Subject	Responsible	Time
1.	**WELCOME**	**Chair**	2 min
2.	**MEETING APOLOGIES / ATTENDANCE**	**Chair**	2 min
3.	**MINUTES FROM MEETING 65**	**Chair**	5 min
4.	**ACTIONS ARISING**	**Chair**	10 min
5.	**MARKET RULES**		
	a) Market Rule Change Overview	**IMO**	5 min
	b) PRC_2013_17: Intermittent Generation Certification	**Alinta**	30 min
	c) RC_2013_18: Synergy-Verve Merger	**Merger Implementation Group**	20 min
	d) PRC_2013_16: Outages and the Application of Availability and Constraint Payments to Non Scheduled Generators	**IMO**	20 min
6.	**CONCEPT PAPERS**		
	a) CP_2013_13: Collection of Market Fees	**Bluewaters Power**	30 min
7.	**SYSTEM RESTART SERVICE ISSUES & UPDATE**	**System Management**	20 min
8.	**MARKET PROCEDURES**		
	a) Overview	**IMO**	5 min

9.	**WORKING GROUPS**		
	a) Overview and membership updates	**IMO**	5 min
10.	**GENERAL BUSINESS**		
	a) Update on LFAS	**IMO/SM**	10 min
11.	**NEXT MEETING: Wednesday 11th December 2013**		

INDEPENDENT MARKET OPERATOR

Market Advisory Committee

Minutes

Meeting No.	65
Location	IMO Board Room Level 17, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date	Wednesday 9 October 2013
Time	12.00pm – 5.00pm

Attendees	Class	Comment
Allan Dawson	Chair	
Kate Ryan	Compulsory – IMO	
Phil Kelloway	Compulsory – System Management	
Andrew Everett	Compulsory – Generator	
Matthew Fairclough	Compulsory – Western Power	Proxy
Will Bargmann	Compulsory – Customer	
Geoff Gaston	Discretionary – Generator	
Michael Zammit	Discretionary – Customer	
Shane Cremin	Discretionary – Generator	
Nenad Ninkov	Discretionary – Customer	
Steve Gould	Discretionary - Customer	
Peter Huxtable	Discretionary – Contestable Customer Representative	
Paul Hynch	Minister's appointee – Observer	Proxy
Wana Yang	Observer – Economic Regulation Authority (ERA)	
Apologies	**From**	**Comment**
Noel Ryan	Compulsory – Western Power	
Andrew Sutherland	Discretionary – Generator	
Also in attendance	**From**	**Comment**
Dean Sharafi	System Management	Presenter
Mike Thomas	Lantau Group	Presenter
Jenny Laidlaw	IMO	Presenter
Brendan Clarke	System Management	Observer
Andy Stevens	Bluewaters Power	Observer

Christian Weeks	EnerNOC	Observer
Paul Troughton	EnerNOC	Observer
Michael Reid	ERA	Observer
Greg Ruthven	IMO	Observer
Aditi Varma	IMO	Observer
Sam Beagley	IMO	Minutes
Oscar Cleaver-Wilkinson	IMO	Observer
Alex Penter	IMO	Observer
Courtney Roberts	IMO	Observer

Item	Subject	Action
1.	**WELCOME** The Chair opened the meeting at 12:22 pm and welcomed members to the 65th meeting of the Market Advisory Committee (MAC).	
2.	**MEETING APOLOGIES / ATTENDANCE** The following **apologies** were received: • Noel Ryan (Compulsory – Network Operator) • Andrew Sutherland (Discretionary – Generator) The following **proxies** were noted: • Matthew Fairclough for Noel Ryan (Compulsory – Network Operator) The following **presenters** and **observers** were noted: • Jenny Laidlaw (presenter, IMO) • Dean Sharafi (presenter, System Management) • Mike Thomas (presenter, Lantau) • Andy Stevens (observer, Bluewaters Power) • Paul Troughton (observer, EnerNOC) • Christian Weeks (observer, EnerNOC) • Michael Reid (observer, ERA) • Greg Ruthven (observer, IMO)	
3.	**MINUTES OF PREVIOUS MEETING** The minutes of MAC Meeting No. 63, held on 7 August 2013, were circulated to members prior to the meeting. The following points were raised by members during the meeting: ***Section 4: Item 24*** • Mr Phil Kelloway requested an amendment be made to this section to include his comments that governor droop control was mandated within the Technical Rules and was different to Load Following	

	Service. ***Section 5a: page 5 of 13*** • Mr Kelloway queried whether there was a mis-match between RC_2013_07: Correction to Minor, Typographical and Manifest Errors and the following comment: *"The Chair proposed that the obligation should be placed on the Market Participant to ensure that capacity is unavailable in the BMO before requesting an outage"* • The Chair advised that the IMO would provide clarification on any ambiguity. ***Section 6c: page 10 of 13*** • Ms Wana Yang requested *"Electricity Act"* to be amended to *"Electricity Industry Act*". *Action Points:* *The IMO to provided clarity to System Management on the mis-match in the 7 August 2013 MAC minutes and RC_2013_07.* *The IMO to amend the minutes of Meeting No. 63 and publish with the minutes of Meeting No. 63 as final.*	 **IMO** **IMO**
4.	**ACTIONS ARISING** The Chair introduced Ms Kate Ryan to update the MAC on the current actions. The following points were noted: • **Item 22:** Ms Ryan identified that System Management had information to provide to the MAC regarding Outage requests and this action point was now closed. Mr Kelloway distributed this information to the MAC. • Mr Kelloway noted that more Outage data was available and if individuals requested more data he could make it available. • Ms Ryan requested clarification on the unit of measure on the data provided. Mr Kelloway confirmed the data was presented as number of Outages. The Chair noted the figures appeared high. • Mr Kelloway agreed the figures appeared high and suggested the filter used may not have excluded transmission Outages. • **Item 34:** Ms Ryan confirmed with Mr Shane Cremin that he had received the required information and this item could now be closed. • **Item 40:** Ms Jenny Laidlaw noted that the IMO had written to ERA and Office of Energy several years ago regarding this issue. Ms Laidlaw believed the ERA had requested more information from the MAC but the issue had not progressed further. • Ms Laidlaw suggested that if the IMO was to resubmit a letter to the ERA, it should specify what the MAC's opinion on the licencing requirements for DSP's should be. • The Chair suggested that DSP's should potentially have their own category for licencing. Mr Geoff Gaston stated he believed DSP's should be required to comply with the code of conduct as they are	

	marketing to small customers. • The Chair indicated the IMO could write to the ERA and suggest licencing for DSP's under a separate category. Ms Yang mentioned this should be a policy decision and the Public Utilities Office (PUO) may be appropriate to make such a decision. • The Chair indicated the ERA and PUO could develop the requirements, which MAC could then review and provide feedback. • Mr Michael Zammit requested clarity that the issue had not been triggered by any wrong-doing, rather to ensure a level playing field. The Chair confirmed this was the case. • The MAC endorsed the IMO to draft a letter to the ERA and PUO and to keep item 40 open. *Action Points:* *The IMO to write a letter to the ERA and PUO requesting consideration of the proposal to ensure DSP's are subject to licencing, specifically under a separate licencing category.*	**IMO**
5a.	**Presentation: Load Following 101** The Chair introduced Mr Dean Sharafi from System Management to deliver a 'Load Following 101' presentation prepared by System Management. MAC members discussed the presentation. The following key comments and queries were made: • Mr Kelloway and Mr Sharafi confirmed that governor control was mandated within the Technical Rules while Load Following, Spinning Reserve and Load Rejection Reserve were covered within the Market Rules. • Mr Cremin questioned if all generators were installed with governor control or did it have to be fitted. Mr Sharafi confirmed that all generators in the WEM were installed with governor control. The Chair requested if the installation of governor control was part of the Technical Rules prior to connection to the network. Mr Sharafi confirmed that this was the case. • The Chair questioned if it was normal for generators to have a deadband in place. Mr Kelloway stated this was the case. Mr Andrew Stevens then question if a deadband of 3 MW was normal or was it deemed small? Mr Kelloway stated he was unsure, noting he was not a member of the Technical Rules committee. • Mr Sharafi stated, based on analysis of other markets, he believed having droop control of 4% was appropriate and the deadband could be increased but this would impact frequency fluctuations. • Mr Stevens queried if any mathematical modelling had been completed to identify the impacts on increasing the deadband and the impacts on the changes governor frequency. Mr Matthew Fairclough noted anyone can suggest changes to the Technical Rules. • Mr Nenad Ninkov requested clarification on the service standards of	

	the governors installed in generators. Mr Andrew Everett advised that droop control can be adjusted as required. Mr Sharafi commented that this standard was part of the Technical Rules and generators are subject to the Technical Rules at the time of connection to the network. Mr Fairclough noted that there may be some 'grandfathering' as generators are obligated to meet the Technical Rules at the time connection of refurbishment. • Mr Gaston sought clarification on how often System Management could change 'real-time' dispatch of Load Following. Mr Kelloway confirmed that 'real-time' dispatch is set up on a ten minute cycle and it is changed three times an Interval. • Ms Aditi Varma sought clarification if Load Following up and down, could be provided by the same machine. Mr Sharafi confirmed this could occur if the generator was set-up for such a service. • Mr Everett noted that Spinning Reserve and Load Rejection are asymmetric, so generators carry more Spinning Reserve than Load Rejection. • Ms Varma requested clarification as to why Spinning Reserve had to cover 70% of the total output of the biggest generator rather than a different percentage. Mr Kelloway stated it was in the Market Rules. Mr Brendan Clarke noted it was likely an economic trade-off and that moving from 70% to 100% would probably double the cost to the market. • The Chair queried whether Load Following and Spinning Reserve were set as being exclusive of each other. Mr Kelloway responded that they were considered cumulative (Load Following was included in the Spinning Reserve requirement) under the Market Rules. • Mr Oscar Cleaver-Wilkinson queried if DSPs currently provide a proportion of Spinning Reserve. Mr Sharafi confirmed that they didn't as their response time is too slow. Mr Paul Troughton noted that this is provided in other markets around the world, including New Zealand. • Mr Kelloway clarified that Interruptable Loads provide category A Spinning Reserve but it is triggered automatically. The Chair thanked Mr Sharafi for the presentation and confirmed that the presentation slides would be available on the IMO website. *Action: the IMO to publish the Load Following 101 presentation on the IMO website.*	**IMO**
5b.	**Presentation: Load Following Investigation** Ms Laidlaw presented the outcomes of an investigation undertaken by the IMO and System Management into the causes and usage of Load Following Ancillary Services (LFAS) during March 2013. The following discussion points were noted. • Mr Michael Zammit queried whether it would be better to compare the LFAS statistics for March 2013 with those of a similar month, for example March 2012, rather than with those of July 2013. Ms Laidlaw replied that the statistics should probably be calculated	

for every month to allow ongoing monitoring.

- Mr Geoff Gaston queried how much of the load forecast variation was due to systemic forecasting errors. Ms Laidlaw responded that the team was yet to determine this.
- The Chair asked Mr Kelloway what steps System Management had taken to improve the quality of its load forecasting. Mr Kelloway noted that a new version of the forecasting software, expected to remove some of the random errors, was currently in test and that work was ongoing to improve the quality of data sources. System Management was still in the process of prioritising the issues to be addressed. Mr Kelloway noted the dependency of the forecasting system on SCADA and Bureau of Meteorology data and suggested there may be limits as to how far the quality of these data sources could be improved. There was some discussion about the reliability of SCADA data and the difference between SCADA data used for forecasting and the “cleansed” data used for settlement.
- Mr Peter Huxtable asked how many of the wind farms in the Wholesale Electricity Market (WEM) were able to control the speed at which they ramped up and down. The Chair noted that in some jurisdictions wind farms voluntarily used feathering to reduce the variability of their output, as a mechanism for reducing the need for load following and the associated costs.
- Ms Laidlaw noted that there appeared to be opportunities to reduce the impact of all of the four LFAS causes examined. There also appeared to be opportunities to sculpt the LFAS Requirement, particularly if LFAS Gate Closure times were reduced.
- Mr Kelloway considered that it was too early to say that the impact of all the causes could be reduced. System Management considered that opportunities do exist, but was not sure that this was in all cases and noted that the benefits of some options may be outweighed by the costs. Mr Kelloway considered that the ongoing work of the team should allow it to identify the most promising opportunities in a reasonably short time frame.
- The Chair suggested that sculpting the LFAS Requirement was likely to provide the greatest benefit relative to its costs. Mr Kelloway agreed that this was definitely worthwhile to pursue, although further work was needed to be certain. Mr Kelloway agreed there were times when the LFAS Requirement could be reduced quite considerably from the standard requirement of +/-72 MW. There was some discussion about whether the current +/-72 MW was a worst case or average value.
- The Chair suggested it would be useful for System Management to start trying to sculpt the LFAS Requirement. Initial steps could include changing the setting of the LFAS Requirement from a back office function to a “front of house” function and some preliminary testing of the sculpting process (i.e. initially without actually reducing the LFAS Requirement).
- Mr Nenad Ninkov questioned to what extent conclusions could be drawn from the analysis, given that it was based on only one month’s data and that 3% of intervals in the month had been

excluded. Mr Kelloway replied that obviously the July 2013 study was required to check for potential seasonal variations. However, the analysis results for the two months would help to identify the obvious areas (applying an 80/20 principle) where improvements could be made for a reasonable cost. Further improvements were likely to require more detailed analysis.

- Mr Stevens noted that in early 2013 the LFAS Requirement was reduced from +/-80 MW to +/-72 MW and questioned whether this had led to any reduction in the percentage of time the system frequency fell between 49.8 Hz and 50.2 Hz. Mr Clarke advised that the frequency performance had not changed. The change in the LFAS Requirement reflected the replacement of the Pinjar units with the Kwinana High Efficiency Gas Turbine (HEGT) units as the primary LFAS units. The HEGT units were more efficient and had better response times than the Pinjar units.
- The Chair suggested it may be possible to carry out some simple sculpting of the LFAS Requirement based on ramping activity, i.e. by reducing the requirement by about 10 MW in periods when ramping activity is expected to be lower. Further reductions could be made in periods of extended calm weather. Mr Kelloway responded that System Management intended to investigate these options. Mr Gaston questioned the time frame for this work and Mr Kelloway responded that timeframes were still to be developed.
- MAC members discussed how the dispatch of Verve Energy Balancing Portfolio (VEBP) Facilities to provide Balancing, LFAS and Spinning Reserve differed from the dispatch of NewGen Kwinana and other IPP Facilities. Ms Laidlaw clarified that unlike NewGen Kwinana, the LFAS providing Facilities in the VEBP were not set to specific base points by the Automatic Generation Control (AGC) system but were allowed to vary between their minimum and maximum output levels in response to changes in the system frequency.
- Ms Laidlaw noted the LFAS Requirement was almost always set to +/-72 MW. Mr Kelloway suggested there was some reduction at certain times, but thought that these reductions may be occurring after LFAS Gate Closure. Ms Laidlaw raised concerns about reducing the quantity of LFAS enabled from the quantities published in the LFAS Merit Order (except where an LFAS Facility failed to deliver its assigned quantity), as this treated LFAS providers unfairly and would act to discourage Market Participants from entering the LFAS Market.
- The Chair noted that Mr Andrew Sutherland had provided some feedback to him on the LFAS paper. Mr Sutherland had commented on the comprehensive nature of the paper but strongly suggested that LFAS Gate Closure time frames need to be considered.
- Mr Gaston questioned why the team had recommended a 10 minute dispatch cycle, given that a five minute dispatch cycle was common in other jurisdictions. Mr Kelloway and replied that a five minute dispatch cycle had been considered by the investigation team. Mr Sharafi noted that as System Management already issued Dispatch Instructions according to a 10 minute cycle and the

proposed change would have no operational impact on Market Participants. Ms Laidlaw noted that while a five minute dispatch cycle may be ideal in the longer term, in the shorter term it could be problematic in that it would reduce the time available to System Management to detect and replace erroneous load forecasts.

- Mr Kelloway questioned whether wind forecasting should be a centralised function or the responsibility of the individual wind Facility operators. There was some discussion about the options for wind forecasting and the incentives for Market Participants to invest in sophisticated wind forecasting tools. Mr Michael Reid suggested that the incentive for Market Participants may increase with a move to "causer pays" allocation of LFAS costs. Mr Cremin considered that causer pays principles should apply to what a Market Participant may be able to control, e.g. ramping, rather than forecasting.
- Ms Yang suggested that if a Non-Scheduled Generator contributed to the LFAS requirement through an incorrect forecast then it should be penalised through the "causer pays" process. This would provide an incentive to improve forecast quality and manage the Facility's output better. Ms Yang suggested that the introduction of a "causer pays" cost allocation should be made a medium term rather than long term priority. Ms Laidlaw noted that a considerable amount of further work was needed to develop an appropriate "causer pays" cost allocation methodology.
- Dr Steve Gould queried why an upgrade of the Real Time Dispatch Engine (RTDE) to allow overrides of non-scheduled generation forecasts was listed as a longer term objective. Mr Sharafi replied that due to the likely IT costs this had been seen as a longer term change, and that a move to ten minute dispatch might reduce the impact of the problem and therefore the benefits of changing the RTDE. Mr Kelloway acknowledged that the costs and benefits of the change had not been examined in detail. Ms Laidlaw considered it would be useful to confirm whether a relatively inexpensive quick fix was possible.
- Ms Laidlaw noted that analysis results for July 2013 were still being validated but would be distributed to MAC members as soon as the Sapere Research Group had completed its review of the analysis.
- The investigation team confirmed it would be providing a further update to the MAC at the November 2013 meeting. The Chair advised MAC members to email details of any questions or issues relating to the LFAS investigation to Ms Laidlaw.
- Mr Will Bargmann questioned how market participants could provide feedback. The Chair suggested the IMO could circulate contact details of the IMO/System Management team to MAC members.

Action Points: The IMO to distribute the results of the July 2013 analysis of LFAS causes and usage to MAC members.	**IMO**
The IMO to publish a copy of the presentation on the IMO website.	**IMO**
The IMO to provide contact details of the IMO/System Management team to MAC members to enable members to provide feedback.	**IMO/All**
The IMO and System Management to provide a progress update on	**IMO/ System**

	their investigation into the LFAS requirement to the November 2013 MAC meeting.	**Mgmt**
6.	**Market Rules Evolution Plan Update** Ms Laidlaw noted that several significant issues had emerged since the 2013-16 Market Rules Evolution Plan (MREP) was finalised in November 2012. The IMO sought the views of MAC members on the relative priority of these issues compared with the issues listed in the MREP. The IMO also sought the views of MAC members on whether the priority of some MREP issues was still appropriate given recent developments. The following discussion points were noted. • Ms Ryan noted that rule changes would be required to support the upcoming merger of Verve Energy and Synergy. The IMO expected the work to be broken into two phases. The first phase was expected to involve the progression of a fast track Rule Change Proposal to address administrative issues relating to the merger. These included name changes, amendments to avoid nonsensical outcomes (such as the inclusion of Demand Side Programmes in the VEBP) and possibly some transitional rules. The second phase was expected to consider the more important issues such as market power mitigation and how the new entity will operate in the market. • Mr Ninkov considered that the review of the WEM proposed to start in early 2014 would have a more profound impact and questioned whether this review affected how the IMO was prioritising its work. The Chair responded that at this point the proposed review was not impacting the IMO's work plan. Several proposals were already in progress and others, such as a move to half hour gate closure, were unlikely to be impacted by the review. The IMO was working under the assumption that the WEM would continue to have a capacity market of some form and would continue to make improvements to the Reserve Capacity Mechanism in line with previous recommendations. • Ms Laidlaw noted that several submissions on the Rule Change Proposal: Limits to Early Entry Capacity Payments (RC_2012_10) supported the concept of removing early capacity payments for all Facilities when there was an excess of capacity in the market. There was general support from MAC members for the IMO to proceed with the development of this proposal. • There was general agreement from MAC members that the development of an Emissions Intensity Index (issue 2 on the MREP list) was no longer a high priority issue. • Mr Fairclough confirmed that Western Power no longer had concerns with the processes used to determine Loss Factors. The MAC agreed that issue 16 on the MREP list (Calculation of Loss Factors) was no longer required. • The Chair noted that while the MREP sets out the high level priorities for the IMO's work, if any of the issues were of a higher priority for participants then they could develop a Rule Change Proposal, which the IMO would be required to process in accordance with the Market Rules. The Chair noted that the IMO	

had recently held a number of discussions with Bluewaters Power about changes to the allocation of Market Fees and Spinning Reserve costs.

- Mr Kelloway questioned whether issue 4 on the MREP (Introducing Market in Spinning Reserve) should be expanded to include consideration of Load Rejection Reserve. Ms Ryan considered that it would be appropriate to wait on the outcomes of the five yearly review of Ancillary Service Standards and the basis for setting Ancillary Service Requirements to be completed in 2014 (Ancillary Services Review) before progressing this issue, but agreed that a Load Rejection Reserve Market could also be considered at that time. Mr Kelloway suggested that the issue should be considered in the context of the Verve Energy/Synergy merger.
- The Chair asked MAC members whether the IMO should consider mitigation of market power issues related to the merger as a priority. Mr Stevens considered there was a lack of clarity in the Market Rules around the definition of market power and that some preliminary work may be required to understand what market power was and how it manifests itself in the WEM. Mr Bargmann expressed concern about trying to establish definitions and rules about market power in the Market Rules when the Competition and Consumer Act (Commonwealth) already covers these matters.
- The Chair noted that the IMO was not intending to duplicate or conflict with existing obligations but noted that the ERA and the IMO had obligations around the monitoring of short run marginal costs that needed to be considered in the context of a merged Synergy/Verve Energy entity. Until more information was available from the Merger Implementation Group it was difficult to progress this work, but the IMO proposed to make resources available to look into the potential issues when more information was available. There was general support from MAC members for the IMO to undertake this work as a priority.
- There was general support from MAC members to retain the high priority of issue 3 (Transition to Half Hour Balancing Gate Closure) and expand its scope to include the reduction of LFAS Gate Closure timeframes. In response to a question from Mr Bargmann, Ms Ryan confirmed that the costs and benefits of the proposal would be considered as part of the rule change process.
- After some discussion, there was general agreement that transition to a 10 minute dispatch cycle should be considered by the IMO in conjunction with the outcomes of the Ancillary Services Review, to ensure consistency in the definitions of dispatch and the LFAS Standard.
- Ms Laidlaw suggested that MREP issue 1 (Additional Improvements to the Balancing Mechanism) could be split into two components. The first component, the removal of Resource Plans, could be progressed relatively quickly, while consideration of changes to the Bilateral Submission and Short Term Energy Market (STEM) processes would require more consideration and was likely to be impacted by the Synergy/Verve Energy merger.
- Mr Gaston considered that the current STEM arrangements were of

	greater concern than the requirement to submit Resource Plans. Mr Stevens disagreed, considering that Resource Plans were now completely superfluous and should be removed as a priority. The Chair suggested that both components should be assigned a high priority but that the removal of Resource Plans could be regarded as "low hanging fruit" and progressed first. There was some discussion about opening the Balancing Horizon for a Trading Day earlier on the afternoon of the Scheduling Day, to provide System Management with a replacement for the information it currently receives through Resource Plans. • Mr Stevens noted that Bluewaters Power found the STEM extremely valuable, while Mr Gaston suggested that the STEM be retained but that participation should be made optional. Ms Ryan proposed to include a discussion of options for Bilateral Submissions and the STEM on the agenda for an upcoming MAC meeting. • Mr Cremin queried when the Resource Plan component of issue 1 could be addressed. Ms Ryan considered that the IMO may be able to present a Concept Paper or Pre Rule Change Proposal to the December 2013 MAC meeting, depending on how much complexity was involved. • Ms Laidlaw questioned the inclusion of the dot point "Link between Balancing Submissions and Facility limit so that a Balancing Submission may contain more capacity than the Facility limit but not less" in MREP issue 1. MAC members agreed that this dot point was not required in the issue description. There was general agreement from MAC members that while the IMO should consider the removal of early entry capacity payments in periods of excess capacity as soon as practicable this work should be assigned a lower priority than the work associated with the Verve Energy/Synergy merger and MREP issues 1 and 3.	
7.	**AFTERNOON TEA** Item moved to prior to Agenda Item 6.	
8.	**CP_2013_06: Dynamic Refunds and Reserve Capacity Price** The Chair invited Mr Mike Thomas to present the Concept Paper. The following key comments were made by members of the MAC regarding the presentation: • Mr Gaston questioned how the eligibility criteria for the rebate pool would work if the previous 30 days coincided with the IMO's testing regime. Mr Thomas responded that the exact mechanics had to be worked out, but in principle, dispatch to meet the IMO's tests would also qualify the plant for rebate eligibility. • Mr Stevens confirmed with Mr Thomas that in the proposed regime, a delayed new Facility would automatically have a minimum refund factor of 1 because of no availability. • Mr Gaston and Mr Stevens also queried whether the rebate pool would be visible to Market Participants. Ms Laidlaw responded that there will be better visibility of the Outages, if not the rebate pool	

	itself. • Mr Gaston and Mr Stevens discussed the application of the proposed regime to decision-making for peaking units. Mr Gaston noted his support for the dynamic refund factors but did not agree with the recycling regime because, in his opinion, recycling exposed peaking units to uneconomic dispatch. He added that more clarity was also needed on how the spare capacity in a Trading Interval would be defined. • Mr Bargmann argued that the recycling regime would give a windfall gain to Market Generators at the expense of taxpayers. He noted that in the present situation, Synergy receives a large subsidy from the Government and taking the refund revenue away from Synergy would imply an added expense to taxpayers to fill that gap. In response to a question from the Chair, he noted that refund revenue was not built into electricity tariffs, instead it would be included in Synergy's profit and distributed to shareholders in increased dividends. He observed that Market Generators would be paid twice in the recycling regime; through capacity payments and through recycling. • Mr Stevens argued that this was not the case because Market Customers receive Capacity Credits for the capacity payment they make to Generators. When in the energy market, a plant declares a Forced Outage, the risk exposure for other generators increases because failure to run penalises them at a higher rate and they stand to lose money. The Chair observed that the current regime might have been instituted at market start to allow Market Customers to buy more Capacity Credits if a generator went on an Outage. However, the fact that this hasn't eventuated implies that there may be a need to reconsider whether better incentives could be created in the market with that revenue. • Mr Thomas highlighted that a real benefit for Market Customers through the recycling regime is that the capacity they have paid for will be incentivised to perform better in the energy market, thereby delivering value when it's needed and deferring the need for new capacity. He highlighted that currently no value was delivered by allocating the revenue to Market Customers. By allocating it to Market Generators, incentives were being created to improve availability. Mr Gaston reiterated that he was not convinced that the recycling of refund revenue would create any incentives for Market Generators to change their behaviour. • The Chair proposed that Mr Gaston's concerns with the proposal would be minuted and the IMO would initiate work on the Rule Change Proposal. • Mr Bargmann questioned if the definition of a Forced Outage that was being considered under another rule change would impact the refunds and recycling regime. Ms Ryan responded that Outage definitions were being considered in PRC_2013_16 and the rule change would be progressed in parallel to allow assessment of whether one influences the other. • Dr Steve Gould commented that, as a Market Customer, he	

	supported the concept of recycling refunds to generators because it would incentivise generators to be available at times of greatest need. • Mr Gaston reiterated that he did not support the proposed Lantau formula to scale the Reserve Capacity Price (RCP) up and down, however, he supported the removal of the 85% set-point for the RCP. He supported the dynamic refund factors, but not the recycling regime. He was also concerned that the impending merger of Verve Energy and Synergy and the ERA's annual review of the market might raise important issues, which would need attention before a rule change for this work could be started. • The Chair acknowledged Mr Gaston's concern but noted that this work was high priority given the stakeholder's concerns around excess capacity. *Action Items: The IMO to amend the pre Rule Change Proposal articulating justifications for the recycling regime and present the PRC to the MAC.* *IMO to publish Mr Thomas' presentation on the IMO website.*	**IMO** **IMO**
9a.	**Market Rule Change Overview** Ms Ryan noted the IMO is not actively consulting on any Rule Changes at present and that the imminent merger of Verve Energy and Synergy has impacted on the work load of the Market Development team.	
9b.	**PRC_2013_16: Availability. Outages and Constraint Payments for Non-Scheduled Generators** The Chair deferred PRC_2013_16 to the next available MAC. Mr Stevens raised concerns regarding the defined terms in the pre Rule Change Proposal, in particular Outages definition. Mr Stevens stated he would consult with the IMO prior to the proposal being presented at the next MAC.	
10.	**MARKET PROCEDURES** Ms Ryan presented the current state of the IMO Market Procedures. The following was noted: • The IMO Procedures and Development Working Group met on 20 September 2013 and discussed several Procedures. Specifically those relating to Prudentials, Certification of Reserve Capacity, Settlement, and Reserve Capacity Performance Monitoring. • Ms Ryan noted all these Procedures should progress into the formal process over the next couple of months once some amendments have been completed. Ms Ryan also noted that there has been a recent change to the IMS Interface Procedure and a large amount of activity on PSOP's, with some Procedures undergoing consultation. • Mr Kelloway mentioned the next discussion with the IMO regarding System Management PSOPs is scheduled for 17 October 2013.	
11.	**WORKING GROUP UPDATE**	

	The Chair moved to nominate Ms Erin Stone (IMO) to the IMO Procedures and Development Working Group as the IMO representative, replacing the position vacated by Ms Fiona Edm~~u~~onds. This nomination was approved by the MAC. The Chair then moved to nominate Mr Stuart Richardson (ERM Power) to the System Management PSOP Working Group. This nomination was approved by the MAC.	
12.	**GENERAL BUSINESS** Ms Yang stated that the ERA is in the process of preparing its 2013 WEM Report for the Minister of Energy, with submissions closing on Monday 14 October 2013. No other general business was noted.	
CLOSED: The Chair declared the meeting closed at 5.11 pm.		

Agenda item 4: 2013 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
22	2013	System Management to provide details at the PRC_2013_09 discussion forum regarding the types and level of outage requests it receives.	SM	Apr	Closed. System Management provided the necessary information at the October 2013 MAC meeting.
34	2013	The IMO to work with Mr Cremin to ensure no unintended consequences arise with respect to the requirement for Intermittent Generators to log outages.	IMO/APA	Aug	Closed.
40	2013	The IMO to request the ERA to review the necessity of a DSP to be licensed.	IMO	Aug	Closed (now included in action point 43).
41	2013	The IMO to provided clarity to System Management on the mis-match in the 7 August 2013 MAC minutes and RC_2013_07.	IMO	Oct	Complete.
42	2013	The IMO to amend the minutes of Meeting No. 63 and publish as final on the IMO website.	IMO	Oct	MAC to confirm additional amendment to the minutes proposed by Ms Wana Yang after the October 2013 MAC meeting.

#	Year	Action	Responsibility	Meeting arising	Status/Progress
43	2013	The IMO to write a letter to the ERA and PUO requesting consideration of the proposal to ensure DSP's are subject to licencing, specifically under a separate licencing category.	IMO	Oct	Underway.
44	2013	The IMO to distribute the results of the July 2013 analysis of LFAS causes and usage to MAC members.	IMO	Oct	Complete. Update be presented at this meeting.
45	2013	The IMO to provide contact details of the IMO/System Management team to MAC members to enable members to provide feedback on the Load Following Investigation.	IMO	Oct	Complete.
46	2013	The IMO and System Management to provide a progress update on their investigation into the LFAS requirement to the November 2013 MAC meeting.	IMO	Oct	Complete. Update to be presented at November MAC.
47	2013	The IMO to reflect the justifications for the recycling regime and present the PRC to the MAC.	IMO	Oct	Underway.
48	2013	The IMO to publish presentations from Agenda items 5 and 8 on the IMO website.	IMO	Oct	Complete.

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)	6th November 2013
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)	2
Standard Rule Changes with 2nd Submission Period Open	1
Standard Rule Changes with 2nd Submission Period Closed (final report being prepared)	0
Rule Changes - Awaiting Minister's Approval and/or Commencement	2
Total Rule Changes Currently in Progress	**5**

The following table provides an update of the items the Market Development team anticipates progressing to the MAC over coming months.

Issue	Likely timing
Outage Planning Phase 2 – Outage Process Refinements	Pre Rule Change Proposal – December MAC Meeting
Changes to the Reserve Capacity Price and Dynamic Refunds Regime	Pre Rule Change Proposal – December MAC Meeting
Limits to Early Certified Reserve Capacity payments in period of excess capacity	Pre Rule Change Proposal – December MAC
Improvements to the Energy Market - options for STEM, Bilaterals and Resource Plans (MREP)	Discussion Paper and/or presentation – December MAC
Settlements package	Pre Rule Change Proposal – Early 2014
Minor Typographical and Manifest Errors	Pre Rule Change Proposal – Early 2014

Issue	Likely timing
Ancillary Services 5 Yearly Review	Review Commencing – Early 2014
Dispatch Issues (from log)	Concept Paper or PRC – Late 2014

Please note these timings are only indicative and may be affected by other issues that arise.

The IMO also notes that it keeps logs of potential issues that may require rule changes, minor and typographical issues and rule change suggestions that is updated on a regular basis. These logs form the basis of the IMO's future rule change work program, including development of the Market Rules Evolution Plan.

APPENDIX 1: FORMALLY SUBMITTED RULE CHANGES (Current as of 6th November 2013)

Standard Rule Change with First Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_10	21/08/2013	Harmonisation of Supply-Side and Demand-Side Capacity Resources	IMO	Draft Rule Change Report published	05/12/2013
RC_2013_09	18/06/2013	Incentives to Improve Availability of Scheduled Generators	IMO	Draft Rule Change Report published	28/11/2013

Standard Rule Change with Second Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2012_23	14/08/2013	Prudential Requirements	IMO	Submissions Close	19/12/2013

Rule Changes Awaiting Commencement/Ministerial Approval

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2013_07	10/09/2013	Correction of Minor, Typographical and Manifest Errors	IMO	Ministerial Approval by	07/11/2013
RC_2013_08	21/05/2013	Market Participant Fees - Clarification of GST Treatment	IMO	Commencement	01/01/2014

INDEPENDENT MARKET OPERATOR

Wholesale Electricity Market Rule Change Proposal

Rule Change Proposal ID: **PRC_2013_17**
Date received: **TBA**

Change requested by:

Name:	Fiona Edmonds
Phone:	08 9486 3009
Fax:	08 9226 4688
Email:	fiona.edmonds@alintaenergy.com.au
Organisation:	Alinta Energy
Address:	Level 13, 1 William Street, Perth, WA 6000 Australia
Date submitted:	TBA
Urgency:	Medium
Change Proposal title:	Correction to estimated output of Intermittent Generation for purposes of Appendix 9
Market Rule(s) affected:	Appendix 9 and new clauses 7.7.5(E), 7.7.5(F), 7.7.5(G) and 7.7.5(H)

Introduction

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

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

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

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

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

The objectives of the market are:

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

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

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

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

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

Details of the Proposed Rule Change

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

Background

Intermittent Generation is currently certified in accordance with the Relevant Level Methodology that is specified in Appendix 9 of Wholesale Electricity Market Rules (Market Rules). The methodology looks at the output of candidate facilities in peak Trading Intervals selected from years prior to the certification period. In particular the methodology requires the IMO to:

- Identify the top 12 Load for Scheduled Generation (LSG)[1] Trading Intervals on separate days in each of the previous five years;
- Calculate the average output of each Intermittent Generator in these 60 Trading Intervals and the variance of the output;
- Set the Relevant Level for the Facility on the basis of its average output less an adjustment factor "G" times the variance of the Facility's output, where "G" is calculated by "K" +"U"/average output.

Note that the parameter "K" is intended to reflect the variability of output of the Intermittent Generator during peak Trading Intervals. The parameter "U" is intended to reflect the uncertainty of the output of the Intermittent Generator during peak Trading Intervals.

In determining the LSG periods adjustments to the metered output of a Facility are made where it was dispatched downwards or suffered a Consequential Outage. For example, where an Intermittent Generator receives downward Dispatch Instructions from System Management the amount of electricity sent out by the Facility, as measured by meter data

[1] LSG is calculated by removing the aggregate output from Intermittent Generation from Operational Load.

submissions received by the IMO, will be lower than would have been the case in the absence of the Dispatch Instruction[2]. To ensure that Facility is not inappropriately penalized at certification in this circumstance an estimate of the output that could have otherwise been achieved by the generator is used in setting the Facility's level of certification. This ensures that the Facility is certified to a level that reflects its true ability to produce electricity during the peak periods (consistent with the intention of the IMO's certification processes).

Estimates of the output of an Intermittent Generator where it is dispatched downwards are determined by System Management in accordance with the Power System Operation Procedure (PSOP): Dispatch and provided to the IMO for the purposes of both settlements and certification under clause 7.13.1(eF). In particular, under step 8.1.2 of the PSOP: Dispatch System Management may utilize any of the following means to estimate the output of the Non-Scheduled Generator (which includes Intermittent Generation):

- A predictive algorithm provided by the Market Participant, providing an assessment of the generators output from relevant independent variables over the Trading Interval;
- A predictive algorithm developed by System Management, providing an assessment of the generators output from relevant independent variables over the Trading Interval;
- An assessment by System Management based on output of the generator in a past Trading Interval under similar conditions; or
- An estimate using participant data provided to System Management that uses output data from particular generating facilities that continue to operate unconstrained after the Dispatch Instruction, with the output data subsequently scaled up to represent the output from all generating facilities that otherwise would have operated.

System Management is required to consult with the relevant Market Participant from time to time regarding which option has been selected by System Management.

Alinta notes that the introduction of the competitive Balancing market (RC_2011_10) changed the relevant rules relating to estimations of an Intermittent Generators output. Previously System Management provided an estimated reduction in output during the relevant interval where the Dispatch Instruction was issued through to the IMO. This information was used by the IMO along with metered output to calculate an accurate estimate of the amount of energy that could otherwise have been produced in the relevant period.

Under RC_2011_10 the rules were changed to require System Management to determine an estimate of the amount of energy that could otherwise be produced. The intention of the estimate was predominantly to feed into the determination of facilities' Theoretical Energy Schedules (TES) and therefore timeliness of its provision became the focus. While the Relevant Level Methodology was updated to directly use this estimate Alinta considers it was an oversight to not ensure that accuracy was retained, consistent with the underlying principle for certification.

Issue

Neither the Market Rules nor the current PSOP: Dispatch currently contemplate the possibility that the estimates provided to the IMO under clause 7.13.1(eF) may require updating to take into account more up-to-date information or to correct for estimation errors. Where the estimates are determined using an algorithm there is a significant reliance on the

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[2] Note that this adjustment to the Market Rules was originally implemented as a result of the Rule Change Proposal: Adjustment to Relevant Level for Intermittent Generation Capacity (RC_2010_24). Subsequent amendments to the overall methodology applied in determining the Relevant Level of an Intermittent Generator, as amended by the Rule Change Proposal: Calculation of the Capacity Value of Intermittent Generation – Methodology 1(IMO) (RC_2010_25) maintained the original amendments implemented by RC_2010_24.

accuracy of any independent variables (input data). Where updated input data is available a significantly different estimate may be produced by System Management. Similarly it's unlikely that any methodology applied to determine an estimate of the output of a generator will always be 100% accurate.

Currently the algorithm generally used by System Management to estimate the output of Intermittent Generators incorporates variables such as the number of turbines, wind speed, capacity factor and actual level of output as measured by SCADA to determine the maximum level of sent out capacity that the Facility could have otherwise produced in the relevant Trading Interval. As the estimate is required to be provided through to the IMO by noon on the first Business Day following the day on which the Trading Day ends (refer to clause 7.13.1) it is likely that more accurate data, such as meter data, will become available afterwards.

For the purposes of the IMO's 2013 round of certification, the estimates for Alinta's windfarm produced by System Management reflected a significantly lower level of output than was actually achieved by the Facility (as reflected by both SCADA and meter data for the relevant Trading Interval(s)). This issue was originally identified by the IMO with a subsequent revision to the estimate being undertaken by System Management. System Management's revision indicated a significantly higher estimate for the windfarm would otherwise have been provided to the IMO. *For clarity Alinta notes that the issue experienced during the 2013 round of certification was not with the input data used in the calculation but rather was more broadly with the methodology applied in calculating the estimates for its windfarm.*

As the original estimate was calculated in accordance with the PSOP: Dispatch the IMO was however unable under the current Market Rules to take into account the revised more accurate value for the purposes of certification. Requiring the IMO to continue to use the original estimate (which the IMO, System Management and Alinta all agreed was incorrect) is an absurd outcome and is inconsistent with the design of the Relevant Level Methodology and the intention of the broader certification processes.

To the extent that the Certified Reserve Capacity assigned to an Intermittent Generator Facility is lower than its actual capacity contribution the Market Participant is disadvantaged financially and its actual level of capacity is not taken into account by the market. Likewise if an estimate is significantly greater than the actual ability of the Facility to produce in a Trading Interval (as compared to its actual metered output) it would be inappropriate for the facility to be certified at the higher level and would result in a distortion between the actual level of capacity available for dispatch by System Management and that which is certified.

Proposal

Given the intention of certification is to reflect the true ability of an Intermittent Generator to produce during the peak LSG periods it is appropriate that a revised estimated value of the potential output of a facility (where a Dispatch Instruction was issued) should be able to be taken into account by the IMO. ***The IMO should not be forced by the Market Rules to use knowingly incorrect information when certifying Intermittent Generators.***

Alinta therefore proposes the following process be adopted in the Market Rules to formally enable revisions to estimates where a Dispatch Instruction was issued and to allow the IMO to take these revised values into account in the Relevant Level Methodology:

- Market Participants or the IMO may request System Management to revise an estimate of its output previously calculated in accordance with clause 7.7.5B and provided to the IMO under clause 7.13.1(eF) (New clause 7.7.5E).

  Alinta notes that it is important that the IMO is able to request a revision to ensure that circumstances where the estimate might be higher than the actual capability of the facility during the relevant interval are also adjusted for given the limited incentives for Market Participants to request a reduction in their estimates in these circumstances;

- Following a request from a Market Participant or the IMO, or where System Management determines it would be appropriate to revise an estimate of a value previously provided to the IMO, System Management must as soon as practicable revise the applicable value in accordance with the process outlined in the PSOP: Dispatch, incorporating any relevant updated information including meter data (New clause 7.7.5F);
- Where System Management's revision results in an alternative estimate it must provide this value through to the IMO for potential use in the Relevant Level Methodology as soon as practicable (New clause 7.7.5G). For the purposes of certification it is only relevant for System Management to provide through a revised estimate where it differs from the original estimate. This will avoid creating additional unnecessary process requirements for System Management; and
- For the purposes of step 4 and step 9(b) of Appendix 9 the IMO may use any revised values provided through to it by System Management under new clause 7.7.5G. It is appropriate that the IMO has discretion to incorporate revised estimates into the Relevant Level Methodology where there would be a material impact on the outcomes of certification. This avoids creating unnecessary administrative burden where there are superfluous changes in data and will indirectly reduce the circumstances where Market Participants request System Management to undertake a re-estimation.

Alinta notes that the predictive algorithm employed by System Management should generally produce accurate results given the methodology that has been developed. As a result it is unnecessary to implement a general requirement for System Management to provide updated estimates once actual meter reads become available for the purposes of certification. Rather it is more appropriate that, as proposed, the IMO is able to take into account updated estimates where they are likely to have a material impact on certification.

For the avoidance of doubt new clause 7.7.5H is proposed to clarify that revised estimates would not apply for the purposes of the Minimum Theoretical Energy Schedule calculation under clause 6.15.2(b) or settlements under Chapter 9.

Alinta's proposed revisions represent a solution that can be implemented in time for the 2014 certification processes, while requiring minimal change to the IMO and System Management's processes.

It is understood that broader changes to address the issue of not enabling TES values to be disputed will be shortly progressed by the IMO (anticipated to be progressed shortly by the IMO). Alinta does not therefore propose any amendments to address these wider issues as part of this Rule Change Proposal so as to avoid any potential delays to rectifying the identified issues relating to the use of estimates in Appendix 9 prior to the 2014 certification processes.

Consequential Outages and requests for Verve Energy to deviate from its Dispatch Plan

Where a Facility experiences a Consequential Outage the estimate of its potential level of output is determined by the IMO (not System Management) in accordance with step 6 of Appendix 9. The information taken into account by the IMO in determining its estimate includes information provided by System Management under clause 7.13.1C. Likewise where Verve Energy is requested to deviate from its Dispatch Plan or change its commitment or output System Management will provide an estimate of its potential level of output which is then taken into account under step 5 of Appendix 9.

In both of these cases the relevant information is provided by System Management on request from the IMO under clause 7.13.1C. It is understood that such a request is likely to only be issued close to the time of certification and therefore is likely to contain the most up-to-date information available. As such Alinta doesn't consider it is necessary to amend the Market Rules to enable Market Participants to request the IMO to reconsider its estimation as part of this Rule Change Proposal. However, should this assumption be incorrect, then further amendments to the rules may be required.

Updates to Market Procedures

Alinta suggests that updates to the Market Procedure for the Certification of Reserve Capacity and to the PSOP: Dispatch may be required to provide further details of the processes for seeking System Management to undertake a re-estimation and the use of revised estimates in the IMO's certification processes.

In this circumstance Alinta does not consider that these procedural changes need to be in place prior to the commencement of any resultant Amending Rules.

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2. Explain the reason for the degree of urgency:

Alinta considers that the IMO should be able to use an estimate of the output of a generator that reflects its true ability to produce energy during the relevant interval. The IMO should not be precluded from using updated estimates from System Management which would materially impact on certification. To force the IMO to use an original estimate where it is known to be materially wrong is an absurd outcome which is inconsistent with the design of the Relevant Level Methodology and the intention of the broader certification processes. Ultimately not utilizing more accurate information means that an accurate representation of the performance of the Non-Scheduled Generator during peak LSG intervals cannot be achieved. This issue needs to be rectified prior to the 2014 certification processes beginning.

Alinta submits the proposed changes into the standard rule change process.

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

7.7.5E. A request for System Management to revise an estimate previously provided under clause 7.13.1(eF) for a Trading Interval may be made by either:

(a) a Market Participant, with respect to any or all of its Non-Scheduled Generators; or

(b) the IMO.

7.7.5F. Following a request under clause 7.7.5E or when System Management has information available to it and application of that information may mean that an estimate previously provided under clause 7.13.1(eF) for a Trading Interval will no longer be accurate, System Management must, as soon as practicable and using the most accurate information available to it, revise the estimate of the maximum amount of sent out energy, in MWh, which the Non-Scheduled Generator would have supplied in the Trading Interval had a Dispatch Instruction not been issued.

7.7.5G. Where the revision by System Management under clause 7.7.5F determines a different value to that provided previously to the IMO under clause 7.13.1(eF), System Management must as soon as practicable provide the revised estimate to the IMO for the purposes of the Relevant Level Methodology.

7.7.5H. For the avoidance of doubt any revised estimates provided under clause 7.7.5G must not be used for the purposes of clause 6.15.2(b)(i) or settlement under Chapter 9.

Appendix 9: Relevant Level Determination

…

Step 4: For each Candidate Facility and Trading Interval identified in step 3(a) use either:

a) the estimate provided by System Management to the IMO under clause 7.13.1(eF); or

b) if a revised estimate has been provided by System Management under clause 7.7.5G, the last such revised estimate where considered appropriate by the IMO ,

as the quantity of energy (in MWh) that would have been sent out by the Facility during the Trading Interval had a Dispatch Instruction not been issued for that Trading Interval.

…

Step 9: Identify, for each 12 month period identified in step 1(c), the following:

(a) the Existing Facility Load for Scheduled Generation previously determined under this Appendix 9 for each Trading Interval in the 12 month period;

(b) the sent out generation (in MWh) for each Candidate Facility for each Trading Interval in the 12 month period that was either:

i. used previously in the determination of the Existing Facility Load for Scheduled Generation for that Trading Interval; or

ii. revised since the IMO's last determination of the Facility's Relevant Level, where the IMO considers it is appropriate to use the last such revised estimate provided by System Management under clause 7.7.5G; and

(c) the 12 Trading Intervals occurring on separate Trading Days that were previously determined to have the highest Existing Facility Load for Scheduled Generation in the 12 month period.

…

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

Alinta considers that the proposed procedural amendments will:

- Improve reliability in the SWIS by more accurately valuing the capacity of Intermittent Generators than under the existing methodology. This is achieved by ensuring that the output taken into account in the Relevant Level Methodology accurately reflects the capability of the generator to produce energy during the peak system demand. System Management will therefore have greater certainty that the capacity available in the market can meet peak demand requirements (Market Objective (a));
- ensure that the best estimate of the output of an Intermittent Generator where it has reduced its output in accordance with a Dispatch Instruction from System Management is used when determining the Relevant Level. This will ensure that an Intermittent Generator is assigned Certified Reserve Capacity based on the best estimate of its output and availability during the five year period accounted for by the Relevant Level Methodology. As the quantity of Certified Reserve Capacity assigned to a Facility that is a Scheduled Generator is not affected by Dispatch Instructions from System Management, the proposed amendments will ensure that Intermittent Generators are not discriminated against (Market Objective (c)).

Alinta considers the proposed amendments are consistent with Market Objectives (b), (d) and (e).

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

Benefits:

- Remove a current distortion in the Relevant Level Methodology.
- Ensure the level of Certified Reserve Capacity assigned to Intermittent Generators reflects their true ability to provide energy during peak demand periods.
- Ensure that Intermittent Generators are fairly compensated by the Reserve Capacity Mechanism.

Costs:

- There may be a slight increase in administrative costs incurred by Market Participants, System Management and the IMO during the certification process in respect of facilities that are Intermittent Generators.
- Alinta notes that the IMO determined to implement a spread sheet solution for calculating the Relevant Level Methodology (refer to the final report for RC_2010_25) and therefore perceives that there should not be any IT costs associated with implementation of its proposed changes.
- Alinta does not consider there will be a substantial number of requests for revised estimates to be used for certification.

Agenda item 5c - Rule Change Proposal: Administrative Amendments Reflecting the Merger of Synergy and Verve Energy (RC_2013_18)

Background

On 10 April 2013, the Western Australian Government announced a merger of the State owned electricity retailer (Synergy) and generator (Verve Energy). On 1 July 2013, a joint Board was established for the newly merged entity, with the expectation that the merger will occur on 1 January 2014. The State Government established the Merger Implementation Group (MIG) to coordinate the implementation of this merger.

To facilitate the merger, the MIG has worked with members of the IMO, Synergy and Verve Energy to discuss operational issues and work through a number of issues related to the Wholesale Electricity Market Rules (Market Rules).

In order to reflect the circumstances of the newly merged entity and ensure that the merger doesn't result in any manifest errors, the MIG has developed a Fast Track Rule Change Proposal: *Administrative Amendments Reflecting the Merger of Synergy and Verve Energy* (RC_2013_18).

The Rule Change Proposal is expected to be submitted into the formal process early in November 2013 under the Fast Track Rule Change Process to allow for the Amending Rules to commence by 1 January 2014.

As a result, at the time of circulating MAC papers for the 13 November meeting, the IMO was unable to include the Rule Change Proposal. However, the IMO will circulate the paper to MAC members once it has been formally submitted.

The IMO notes that this Rule Change Proposal only includes administrative changes. Further changes may be required in 2014 to address other issues, such as those relating to market power.

Recommendation

The IMO requests that the MAC:

- Note the delay in the circulation of the paper associated with this agenda item; and
- Review the paper following circulation in preparation for discussion at the meeting.

Wholesale Electricity Market
Pre Rule Change Proposal

Rule Change Proposal ID: **PRC_2013_16**
Date received: **TBA**

Change requested by:

Name:	Allan Dawson
Phone:	08 9254 4333
Fax:	08 9254 4399
Email:	Allan.Dawson@imowa.com.au
Organisation:	IMO
Address:	Level 17, 197 St Georges Terrace, Perth WA 6000
Date submitted:	TBA
Urgency:	2-medium
Change Proposal title:	Outages and the Application of Availability and Constraint Payments to Non-Scheduled Generators
Market Rules affected:	Clauses 3.21.1, 3.21.1A (new), 3.21.2, 3.21.2A (new), 3.21.2B (new), 3.21.3, 3.21.4, 3.21.5, 3.21.6, 3.21.7, 3.21.7A (new), 3.21.7B (new), 3.21.8, 4.11.1, 6.15.1, 6.15.2, 6.15.3, 6.15.4, 6.16A.1, 6.16A.2, 6.16B.1, 6.16B.2, 6.17.3, 6.17.3A, 6.17.4, 6.17.4A, 6.17.5, 6.17.5A, 6.17.5B, 6.17.5C, 7.7.5A, 7.7.5B, 7.7.5D, 7.7.6B, 7.13.1A, Glossary, Appendix 10 (new) and Appendix 11 (new).

Introduction

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

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

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

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

The objectives of the market are:

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

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

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

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

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

Details of the Proposed Rule Change

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

Background

Currently the Market Rules do not adequately accommodate the circumstances of Non-Scheduled Generators as the concepts of availability, outages, constraint payments apply. The resulting ambiguity has resulted in some Non-Scheduled Generators being paid compensation as the result of a Network Outage. This is inconsistent with the application of the Market Rules to Scheduled Generators.

This pre Rule Change Proposal seeks to address the ambiguity with respect to the obligations on Non-Scheduled Generators. It also ensures that the Market Rules that ultimately determine the application of compensation payments are complete and robust.

In particular, the IMO proposes to provide greater clarity on the:

- definition of an Outage;
- quantity of an Outage that a Non-Scheduled Generator must log;
- requirement for Market Participants to log Outages which they become aware of following the 15 day timeframe, and for System Management to report these to the IMO;
- requirement for the IMO to provide System Management with each Facility’s Reserve Capacity Obligation Quantity for the purposes of Outage calculations;

- application of constrained on and off compensation to Market Participants; and
- application of the Forced Outage rate and Planned Outage rate to Non-Scheduled Generators for the purposes of setting Certified Reserve Capacity.

A Concept Paper which outlined these issues was presented at the Market Advisory Committee meeting held on 7 August 2013. Two key questions were raised which have informed the drafting to implement the necessary changes. These related to:

1. The practicalities of logging Outages for a Non-Scheduled Generator, noting that it would be complex to determine pro-rated Outage quantities based on an ex-post review of each minute; and

2. The necessity to align incentives to make capacity available for Non-Scheduled Generators as they already have sufficient commercial incentive to be available.

The IMO has considered these issues in the context of the proposed amendments.

Issues to be addressed in the existing Market Rules

Definition of an Outage

Currently the Market Rules defines an Outage as:

…means a Forced Outage, a Planned Outage or a Consequential Outage.

The definitions of each type of Outage referred to in the glossary definition of an Outage do not provide any specificity about what a Market Participant must log, particularly as they apply to where:

1. a Facility is able to provide capacity but, due to a Network constraint, the Network is unable to accept its capacity while maintaining operation within the Technical Envelope to ensure a safe, reliable and stable Network.

2. a Facility's production is limited to reduce the potential of damage to the Facility or to ensure safety of its workers. For example, a wind farm may have an automatic trip in place for periods of extreme wind.

3. a Non-Scheduled Generator which relies on a renewable fuel source may be unable to provide capacity without the appropriate fuel. For example, at night for solar generation and during low wind periods for wind farms.

This lack of clarity around the requirement to log Outages has resulted in an inconsistent approach from Market Participants and has led to spurious payments of constrained off compensation to Market Participants where Outages should have been logged but were not explicitly accounted for in the Market Rules.

In order to ensure all Outages are logged as applicable and thereby address the spurious constrained off compensation payments, the IMO proposes to provide further clarity around the definition of an Outage by introducing two new clauses, clause 3.21.1 and 3.21.1A, into the Market Rules and amending the definition of 'Outage' in the Glossary to refer to the new clause 3.21.1 of the Market Rules.

In order to improve the integrity of the Market Rules, the current clause 3.21.1 which provides the definition of a Forced Outage has also been renumbered to clause 3.21.2B to better reflect the Outage approvals process. This amendment will also be reflected in the definition of 'Forced Outage' in the Glossary. The definition of 'Forced Outage' will also be moved to ensure the Glossary is in alphabetical order.

Logging of an Outage in advance

The Market Rules currently do not consider the ability for a Market Participant to log a Consequential Outage in advance of the Outage occurring. The ability for a participant to log an Outage in advance will improve the transparency of Facility availability and thereby improve the price signals to other Market Participants.

The IMO proposes to amend clauses 3.21.2, 3.21.3 and 3.21.4 of the Market Rules and introduce the new clause 3.21.2A which will enable Market Participants to log Outages as soon as the participant is notified of an Outage by the Network Operator or other Rule Participant.

Quantity of de-rating for a Non-Scheduled Generator

The Market Rules currently require Market Participants and the Network Operator to inform System Management of an Outage of a Facility or item on the list under clause 3.18.2, or to which clause 3.18.2A applies, as soon as practicable.

Clause 3.21.4 of the Market Rules outlines the information that must be provided to System Management with respect to the notification of an Outage. This includes the time the Outage commenced, an estimate of the time the Outage is expected to end, the cause of the Outage, the Facility or items affected and the expected quantity of the Outage.

However, currently clause 3.21.4(e) can only be applied to Scheduled Generators as the quantity of an Outage is calculated in accordance with clause 3.21.5, which requires the quantity to be determined with respect to a Facility's maximum capacity as adjusted using the Standing Data for temperature dependence under in Appendix 1(b)(iv). This section of Appendix 1 outlines the Standing Data required for Scheduled Generators only, resulting in ambiguity about how to determine the quantity of any reduction in capacity of a Non-Scheduled Generator for the purposes of Outage calculations.

Similarly, clause 3.21.6 provides the process by which System Management determines the MW reduction of a Facility's output as the result of an Outage. Currently, Market Participants enter Outage data on a sent out basis at 15 degrees Celsius. System Management then converts the value to a sent out basis at 41 degrees Celsius and adjusts it based on the Facility's Reserve Capacity Obligation Quantity (RCOQ). System Management then calculates the total MW quantity of Forced, Planned and Consequential Outages under clauses 3.21.6(b) to 3.21.6(d) and provides this for each Facility to the IMO as required under clauses 7.3.4 and 7.13.1A(b). However, the application of clause 3.21.6 to a Non-Scheduled Generator is currently inappropriate because Non-Scheduled Generators have an RCOQ of zero. This would result in a negative Outage quantity where the MW reduction in the output of a Facility is greater than its RCOQ.

The IMO proposes to amend clause 3.21.5 of the Market Rules to add new sub-clauses to explicitly provide alternative calculations for Non-Scheduled Generators and the Verve Energy Balancing Portfolio. The proposed Amending Rules require the quantity of the reduction in capacity of a Non-Scheduled Generator to be calculated by reference to its Sent Out Capacity.

The IMO has also taken the opportunity to propose further changes to clause 3.21.5 to provide further clarity on the Outage data required to be logged, by introducing the concept of an average reduction in capacity over the Trading Interval. This is not a new requirement but its inclusion will ensure that all Market Participants provide consistent Outage data.

In addition, the IMO proposes to amend clause 3.21.6 of the Market Rules to add new sub-clauses to provide alternative calculations to determine a Facility's Outage for a Non-Scheduled Generator. The alternatives will use the Outage data on a sent out basis at 15 degrees Celsius and calculate a sum of all Forced, Planned and Consequential Outages as applicable.

Provision of data by the IMO to System Management for the calculation of Outages

Clause 3.21.6(e) of the Market Rules requires the IMO to provide System Management with the RCOQ for each Facility as currently applicable. This is to be used in System Management's calculation of the Outage quantity for Scheduled Generators to determine the reduction of capacity associated with an Outage, as opposed to its maximum quantity.

However, practically, the IMO cannot determine in advance of a Trading Interval each Facility's RCOQ. For example, the RCOQ must account for factors including temperature and Outage quantities which may restrict the ability of the Facility to provide energy at any particular point in time. While this is not practical for either the Market Participant to provide the IMO with this type of information, or the IMO to be considering it with respect to the capability of the Facility, it is also not necessary.

To date, the IMO has provided System Management with each Facility's MW value of Capacity Credits rather than its RCOQ. While there is a difference between the two values, it is not expected to result in significantly different outcomes for the purpose of calculating a Facility's Outage values or a Facility's Certified Reserve Capacity.

The IMO therefore proposes to amend clause 3.21.6(e) of the Market Rules to align to current practice by requiring the IMO to provide each Facility's MW value of Capacity Credits, rather than it's RCOQ. In addition, the IMO proposes to amend clauses 3.21.6(b) to (d) as they apply to Scheduled Generators to reflect this.

It should be noted that this amendment will align the Market Rules to current operational practices and therefore will not impact outcomes for Scheduled Generators.

Provision of Outage data by System Management to the IMO for certification

Currently, System Management provides Outage data for each Facility for each Trading Interval to the IMO as temperature adjusted values (at 41 degrees Celsius) under clause 7.13.1A of the Market Rules. This means that the IMO often does not know the total MW value of the reduction associated with the Outage.

To ensure that the IMO can calculate the impact of Outages on availability and consider it in the certification process, the IMO also requires Outage data to be provided on a sent out basis at 15 degrees Celsius.

The IMO proposes to amend clause 7.13.1A of the Market Rules to require System Management to provide the MW quantity of the reduction in a Facility's capacity for each Facility for each Trading Interval on a sent out basis at 15 degrees Celsius for both Scheduled and Non-Scheduled Generators together with the current temperature adjusted values provided for Scheduled Generators.

The IMO will also work with System Management to revise section 8.1 of the *Power System Operation Procedure (PSOP): Dispatch* to provide greater clarity on calculation of the expected quantity and ensure that all Outages are included for a Non-Scheduled Generator. This value is used in calculating the Minimum TES and affects a Facility's certification and therefore should be as accurate as possible.

Setting Certified Reserve Capacity for Non-Scheduled Generators

The Rule Change Proposal *RC_2013_09: Incentives to Improve Availability of Scheduled Generators* was developed to allow the IMO more flexibility in assigning Certified Reserve Capacity to Scheduled Generators that display excessive Outage rates over a three-year period. The proposed Amending Rules in RC_2013_09 change the IMO's process for setting a Facility's Certified Reserve Capacity under clause 4.11.1(h) of the Market Rules.

Clause 4.11.1(h) of the Market Rules is currently unable to be applied to Non-Scheduled Generators as the calculations of the Planned Outage Rate and Forced Outage Rate referred to in this clause only consider the application to a Scheduled Generator. The *PSOP: Facility Outages* contains the calculations of both the Forced Outage rate and the Planned Outage rate that clause 4.11.1(h) refers to.

The IMO believes that the introduction of greater incentives for Scheduled Generators to maximise the availability of their capacity as provided in RC_2013_09 should equally apply to Non-Scheduled Generators and therefore proposes to introduce amendments to the Market Rules to align such incentives.

Further, the calculations as they currently stand in the PSOP rely on the MW value of the Outage being reduced from the MW value of Capacity Credits. While this works for a Scheduled Generator, for a Non-Scheduled Generator, the reduction in capacity of an Outage is likely to be significantly greater than the MW value of Capacity Credits, resulting in a nonsensical Outage value.

The IMO proposes that, for the purposes of calculating the Planned Outage Rate and Forced Outage Rate for a Non-Scheduled Generator, the Outage quantity is specified as the MW quantity by which the Sent Out Capacity of a Facility is reduced.

The IMO also proposes that, with the increasing significance of these calculations as a result of RC_2013_09, they should be removed from the *PSOP: Facility Outages* and introduced as Appendix 10 of the Market Rules. The IMO has taken the opportunity to streamline the equations to provide greater clarity over the calculations being undertaken.

The proposed changes to the Planned Outage Rate and Forced Outage Rate equations have been included in Appendix 10 and align with the proposed Amending Rules for RC_2013_09 contained within the Draft Rule Change Report. In addition, the definitions for 'Planned Outage Rate' and 'Forced Outage Rate' have been introduced in the Glossary and, for the purposes of clause 4.27.3 as amended in RC_2013_09, the definition of 'Equivalent Planned Outage Hours' has been amended.

It should be noted that the proposed amendment will not affect the application of the calculations to Scheduled Generators.

Timeframes for providing information of Outages to System Management

Clause 3.21.7 of the Market Rules provides the timeframe under which Market Participants or Network Operators must provide 'full and final details' of the relevant Planned, Forced or Consequential Outage to System Management. However, for an Outage that spans multiple Trading Days, based on the current drafting, it is unclear on which Trading Day the 15 day timeframe should start.

The IMO proposes to amend clause 3.21.7 and 3.21.8 of the Market Rules to refer to 15 calendar days following the Trading Day on which the Outage commenced.

Furthermore, the obligation to provide 'full and final details' of an Outage no later than 15 calendar days following the Trading Day on which the Outage commenced is impractical as this information may not yet exist for Outages that extend for more than the 15 days. For example, if an Outage is expected to continue for 20 days, a Market Participant cannot be expected to provide 'full and final details' of the entire Outage before it is finished.

The IMO proposes that, given its reference to 'full and final details', clause 3.21.7 of the Market Rules should be amended to specifically refer to a particular Trading Day affected by the Outage. This provides Market Participants with the ability to update the Outage information for each affected Trading Day on a rolling basis until the conclusion of the Outage, but retains the requirement to provide final details for each affected Trading Day within the 15 day timeframe.

Timeframes for providing information of Outages to the IMO

Clause 7.13.1A currently requires System Management to provide the IMO with the Outage data for a Trading Day within 15 Business Days. Currently, the drafting of this clause does not allow System Management to accept or provide to the IMO any information for Outages logged after the 15 calendar days. This may result in Facilities being assigned Certified Reserve Capacity based on inaccurate information.

In order to ensure that the IMO is aware of all Outages, the IMO proposes to introduce two new clauses in the Market Rules. Clause 3.21.7A requires Market Participants to provide all Outage data to System Management as soon as practicable, regardless of the reporting timeframes. Clause 3.21.7B then requires System Management to provide this information to the IMO in accordance with clause 7.13.1A of the Market Rules.

Removing constrained on and off compensation where a Facility is non-compliant

Constrained on and off compensation is paid where a Facility is not dispatched in accordance with the Balancing Merit Order.

Currently, Scheduled Generators receive constrained on and off compensation when they are clearly non-compliant with Dispatch Instructions issued by System Management. For example, where a Scheduled Generator produced more than its target End of Interval quantity, it is paid for a quantity above what it would otherwise produce based on its dispatch under the Balancing Merit Order. However, this is based on the inherent assumption in the Market Rules that the only reason a generator would deviate from its Dispatch Instruction is because of an Outage, or where they are dispatched Out of Merit.

This has led to Scheduled Generators who are not compliant with Dispatch Instructions being paid constrained on or off compensation in the initial settlement for the total amount produced, with the determination of a Facility's compliance or otherwise occurring after settlement. The IMO Compliance Team is responsible for investigating the merit of any constrained on or off compensation as it relates to a Facility's compliance with Dispatch Instructions issued by System Management.

Recently, there have been a number of situations where these (often large) incorrect payments have been included in the initial settlement. As they are only able to be removed as part of the first or second settlement Adjustment Process, the delays will lead to an inequity between Market Participants resulting from the time value of money. Furthermore, the payment could result in an increase in the required level of Credit Support to be provided by the Market Participant.

As constrained on and off compensation is intended to be paid only when a Facility is dispatched Out of Merit, the IMO proposes to make a number of changes to the Out of Merit calculations currently contained in clauses 6.16A.1 and 6.16A.2 of the Market Rules. This will effectively cap the constrained quantity to the Dispatch Instruction to remove the instances resulting in incorrect payments.

The amendments proposed in this pre Rule Change Proposal will result in the Minimum TES reflecting all Outages of a Facility as provided in the Dispatch Schedule, thereby also ensuring that Market Participants are not paid Out of Merit compensation when a Facility is unavailable. The IMO will calculate a Facility's Minimum TES by reference to its Dispatch Schedule. This will require the IMO to calculate the Dispatch Schedule from the Dispatch Instructions provided by System Management. This will require changes to the IMO's IT and settlement systems and processes.

The IMO also proposes to move the calculations for:

- Maximum and Minimum TES currently contained in clauses 6.15.1 and 6.15.2;
- Out of Merit Generation currently contained in clauses 6.16A.1, 6.16A.2, 6.16B.1 and 6.16B.2; and
- constrained on and off payments currently contained in clause 6.16.3, 6.17.4, 6.17.4A, 6.17.5, 6.17.5A and 6.17.5B.

to Appendix 11 of the Market Rules and present them as mathematical formulae to improve clarity. The requirement to determine these elements will continue to remain in amended clauses 6.15.1, 6.15.3, 6.16A.1, 6.16A.2, 6.17.3 and 6.17.4 of the Market Rules

As a result of the removal of clauses 6.17.5, 6.17.5A and 6.17.5B, clause 6.17.5C of the Market Rules will be renumbered to clause 6.17.5. References to current clauses containing the TES calculations in clauses 7.7.5A, 7.7.5B and 7.7.5D of the Market Rules and defined terms 'Maximum Theoretical Energy Schedule' and Minimum Theoretical Energy Schedule' are also proposed to be amended to refer to Appendix 11.

The IMO also notes that, following the initial Dispatch Instruction, System Management is currently able to issue a second Dispatch Instruction to Market Participants. This is often used to reflect the expected output when a Facility is unable to comply with a Dispatch Instruction, to rectify the non-compliance as currently required under clause 7.7.6B of the Market Rules.

The IMO needs to be able to differentiate these rectification Dispatch Instructions from others to determine the appropriate Dispatch Schedule on which to base a Facility's TES. The IMO proposes to introduce the defined term 'Rectification Dispatch Instruction' in the Glossary and clarify Dispatch Instruction inputs in each equation in Appendix 11 with respect to this definition. This ability to differentiate Dispatch Instructions will require changes to both System Management and IMO systems.

Impact on the Regulations

The IMO notes that under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* (WEM Regulations), clauses 3.21.4 and 7.7.6A are subject to Category C civil penalties.

The IMO considers that under the proposed Amending Rules it is still appropriate for these clauses to remain a Category C civil penalty provisions as the intent of these clauses has not changed.

This pre Rule Change Proposal does not amend, remove or add Protected Provisions under clause 2.8.13 of the Market Rules.

2. Explain the reason for the degree of urgency:

The IMO proposes to commence the proposed Amending Rules set out in this pre Rule Change Proposal in order to align the changes with the amendments being developed as a result of Phase 2 of the Outage Planning Review.

This will allow Rule Participants to consider the changes associated with Outages more holistically. Furthermore, this is expected to reduce the implementation costs to Market Participants by aligning any system and IT changes that may be required.

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 <u>underline</u> words added)*

~~3.21.1. A Forced Outage is any outage of either a Facility or item of equipment on the list described in clause 3.18.2 or a Facility or generation system to which clause 3.18.2A relates that has not received System Management's approval, including:~~

~~(a) outages or de-ratings for which no approval was received from System Management, excluding Consequential Outages;~~

~~(b) any part of a Planned Outage that exceeds its approved duration; and~~

~~(c) where the Market Participant or Network Operator does not follow a direction from System Management under clause 3.20.1 to return the equipment to service within the time specified in the appropriate contingency plan.~~

<u>3.21.1 Subject to clause 3.21.1A, an **Outage**:</u>

<u>(a) is a:</u>

<u>i. physical event that results in or gives rise to; or</u>

<u>ii. a circumstance that creates safety concerns that a prudent Market Participant would address by:</u>

<u>a temporary limitation that:</u>

<u>(b) affects the technical capability of:</u>

<u>i. a Facility or item of equipment on the list described in clause 3.18.2; or</u>

<u>ii. a Facility or generation system to which clause 3.18.2A applies; and</u>

<u>(c) results in a partial or complete reduction in:</u>

<u>i. the quantity of electricity that the Facility or generation system would otherwise be able to generate;</u>

<u>ii. the quantity of electrical energy that is available to System Management for dispatch in accordance with clauses 7.6.1 and</u>

7.6.1C (including where the Facility, item of equipment or generation system is temporarily not electrically connected to the SWIS); or

iii. the quantity of electrical energy that can be transferred into a transmission or distribution system that:

1. forms part of the SWIS; or

2. is electrically connected to the SWIS,

in accordance with clause 7.6.1 due to a limitation affecting that transmission or distribution system.

3.21.1A An **Outage**:

(a) includes a lack of fuel provided the elements of clauses 3.21.1(b) and (c) are met;

(b) does not include a limitation referred to in clause 3.21.1(b) to the extent it arises from an intermittent energy source used by a Facility to generate electrical energy.

3.21.2. A Consequential Outage is an O~~o~~utage that~~of either a Facility or item of equipment on the list described in clause 3.18.2 or a facility or generation system to which clause 3.18.2A relates, for which no approval was received from System Management, but which~~ System Management determines:

(a) was or will be caused by a Forced Outage to another Rule Participant's equipment and would not have occurred if the other Rule Participant's equipment did not suffer a Forced Outage; or

(b) was or will be caused by a Planned Outage to a Network Operator's equipment and would not have occurred if the Network Operator's equipment did not undertake the Planned Outage~~,~~;

but excludes any O~~o~~utage deemed not to be a Consequential Outage in accordance with clause 3.21.10.

3.21.2A System Management must determine, as soon as reasonably practicable, whether an Outage is a Consequential Outage.

3.21.2B A Forced Outage is an Outage other than a Planned Outage or a Consequential Outage, and includes:

(a) any part of a Planned Outage that exceeds its approved duration; and

(b) where the Market Participant or Network Operator does not follow a direction from System Management under clause 3.20.1 to return the Facility or equipment to service within the time specified in the relevant Outage Contingency Plan.

3.21.3. System Management must keep a record of all Forced Outages and Consequential Outages of which it ~~is~~ becomes aware.

3.21.4. If a Facility or item of equipment that is on the list described in clause 3.18.2 or a Facility or generation system to which clause 3.18.2A relates is affected or likely to be affected by ~~suffers~~ a Forced Outage or Consequential Outage, then the relevant Market Participant or Network Operator must inform System Management of that ~~e o~~Outage as soon as practicable, including before the Outage occurs. Information provided to System Management must include:

(a) the time the ~~o~~Outage is expected to commence, or did commence~~d~~;

(b) an estimate of the time the ~~o~~Outage is expected to end;

(c) the cause of the ~~o~~Outage;

(d) the Facility or item of equipment or Facilities or items of equipment affected; and

(e) for each affected Facility or item of equipment, the expected quantity of any de-rating by Trading Interval, where, if the Facility is a generating system, this quantity is to be submitted in accordance with clause 3.21.5.

3.21.5. The quantity of an outage notification submitted to System Management:

(a) for a Scheduled Generator, is the reduction in capacity from the relevant Facility's maximum capacity measured as an average over the Trading Interval on a sent out basis at 41 degrees Celsius where the maximum capacity is as found in the Standing Data file for Temperature Dependence provided under Appendix 1(b) iv and converted to a sent out basis at 41 degrees Celsius~~. The remaining capacity, determined as the maximum capacity minus the notified outage, must be available to System Management for dispatch.~~;

(b) for a Non-Scheduled Generator, is the reduction in capacity from the relevant Facility's Sent Out Capacity measured as an average over the Trading Interval; or

(c) for the Verve Energy Balancing Portfolio, is the sum of the reduction in capacity for all Outages from:

i. the sum of the maximum capacity of all Scheduled Generators in the Verve Energy Balancing Portfolio, measured as an average over the Trading Interval on a sent out basis at 41 degrees Celsius where the maximum capacity is as found in the Standing Data file for Temperature Dependence provided under Appendix 1(b) iv and converted to a sent out basis at 41 degrees Celsius; plus

ii. the sum of the maximum capacity of all Non-Scheduled Generators in the Verve Energy Balancing Portfolio, where the maximum capacity is the Facility's Sent Out Capacity measured as an average over the Trading Interval.

3.21.6. The following will apply for the purposes of clauses 7.3.4 and 7.13.1A-(b):

(a) outage data will be entered by Market Participants in System Management's computer interface system on a sent out basis at 15 degrees Celsius;

(aA) for a Scheduled Generator, System Management will use the Outage data entered by Market Participants in System Management's computer interface system on a sent out basis at 15 degrees Celsius and, in addition, convert the outage data to a sent out basis at 41 degrees Celsius by multiplying the outage quantity at 15 degrees Celsius by the ratio of the maximum capacity at 41 degrees Celsius to the maximum capacity at 15 degrees Celsius for the Facility as found in the Standing Data file for temperature dependence provided under Appendix 1(b)-(iv) on a generated basis for that facility. Market Participants will submit the outage data at 41 degrees Celsius as displayed by System Management's computer interface system;

(aB) for a Non-Scheduled Generator, System Management will use the Outage data entered by Market Participants in System Management's computer interface system on a sent out basis at 15 degrees Celsius;

(b) System Management will calculate the Forced Outage ~~(on a sent out basis at 41 degrees Celsius)~~ for a Facility in a Trading Interval as the greater of:

i. zero; and

ii. for a Scheduled Generator, the sum of all Forced Outages notified for that Facility minus the difference of the Facility maximum capacity and its ~~Reserve Capacity Obligation Quantity~~MW value of Capacity Credits; or

iii. for a Non-Scheduled Generator, the sum of all Forced Outages notified for that Facility;

(c) System Management will calculate the Planned Outage ~~(on a sent out basis at 41 degrees Celsius)~~ for a Facility in a Trading Interval as the greater of:

i. zero; and

ii. for a Scheduled Generator, the sum of all Planned Outages minus the greater of:

1. zero; and

2. the maximum capacity of the Facility minus its ~~Reserve Capacity Obligation Quantity~~ MW value of Capacity Credits minus the sum of all Forced Outages notified for the Facility before the adjustment in (b) above is made by System Management; and

iii. for a Non-Scheduled Generator, the sum of all Planned Outages notified for the Facility before the adjustment in (b) above is made by System Management;

(d) System Management will calculate the Consequential Outage ~~(on a sent out basis at 41 degrees Celsius)~~ for a Facility in a Trading Interval as the greater of:

i. zero; and

ii. for a Scheduled Generator, the sum of all Consequential Outages minus the greater of:

1. zero; and

2. the maximum capacity of the Facility minus its ~~Reserve Capacity Obligation Quantity~~ MW value of Capacity Credits minus the sum of all Forced Outages and the sum of all Planned Outages notified for the Facility before the adjustments in (b) and (c) above are made by System Management; and

iii. for a Non-Scheduled Generator, the sum of all Consequential Outages notified for the Facility before the adjustments in (b) and (c) above are made by System Management;

(e) the IMO will provide System Management ~~the Reserve Capacity Obligation Quantity of~~a MW quantity corresponding to the number of Capacity Credits assigned to each Facility as currently applicable; and

(f) the maximum capacity used in this clause is the value defined in clause 3.21.5.

3.21.7. Notwithstanding the requirements of clause 3.21.4 that a relevant Market Participant or Network Operator must inform System Management of a Forced Outage or Consequential Outage as soon as practicable, a Market Participant or Network Operator must provide full and final details of the relevant Planned Outage, Forced Outage or Consequential Outage to System Management no later than 15~~fifteen~~ calendar days following each ~~the~~ Trading Day on which the Outage occurred or continued to occur.

3.21.7A. If a Market Participant or Network Operator fails to provide full and final details of an Outage to System Management in accordance with clause 3.21.7 for any reason (including where the Market Participant or Network Operator first becomes aware of a Forced Outage or Consequential Outage more than 15 calendar days after the first Trading Day on which the Outage occurred), then the Market Participant or Network Operator must provide those full and final details to System Management as soon as practicable.

3.21.7B. Where System Management is notified of an Outage under clause 3.21.7, it must, as soon as practicable, provide this information to the IMO in accordance with clause 7.13.1A.

3.21.8. If a Market Participant considers that one of its Facilities has suffered a Consequential Outage then the Market Participant ~~may provide~~ must notify System Management with a notice confirming details of the Consequential Outage no later than 15 calendar days following the Trading Day on which the Consequential Outage for a Trading Interval ~~commenced~~ occurred. The notice must:

(a) be signed by an Authorised Officer of the Market Participant;

(b) confirm that a Consequential Outage has occurred; and

(c) provide details (to the best of its knowledge) of the events which resulted in the Consequential Outage.

…

4.11.1. Subject to clauses 4.11.7 and 4.11.12, the IMO must apply the following principles in assigning a quantity of Certified Reserve Capacity to a Facility for the Reserve Capacity Cycle for which an application for Certified Reserve Capacity has been submitted in accordance with clause 4.10:

…

(h) subject to clauses 4.11.1B and 4.11.1C, the IMO may decide not to assign, or to assign a specified quantity of Certified Reserve Capacity to a Facility if:

i. the Facility has been in Commercial Operation for at least 36 months and has had a Forced Outage Rate or a combined Planned Outage Rate and Forced Outage Rate of greater than the applicable percentage specified in clause 4.11.1D over the preceding 36 months; or

ii. the Facility has been in Commercial Operation for less than 36 months, or is yet to commence Commercial Operation, and the IMO has cause to believe that over the first 36 months of Commercial Operation the Facility is likely to have a Forced Outage Rate or a combined Planned Outage Rate and Forced Outage Rate greater than the applicable percentage specified in clause 4.11.1D,

where the Planned Outage Rate and the Forced Outage Rate for a Facility for a period will be calculated in accordance with ~~the Power System Operation Procedure~~ Appendix 10;

[Note: Drafting of clause 4.11.1(h) reflects proposed Amending Rules in the Draft Rule Change Report for RC_2013_09: Incentives to Approve Availability of Scheduled Generators]

…

6.15. Maximum and Minimum Theoretical Energy Schedule

~~6.15.1. The Maximum Theoretical Energy Schedule in a Trading Interval is:~~

~~(a) for a Balancing Facility which is a Scheduled Generator:~~

~~i. the maximum amount of sent out energy, in MWh, which could have been dispatched in the Trading Interval from Balancing Price-Quantity Pairs in respect of the Balancing Facility with a Loss Factor Adjusted Price less than or equal to the Balancing Price; plus~~

~~ii. if the Facility's SOI Quantity is greater than the sum of the quantities in the Facility's Balancing Price-Quantity Pairs which have a Loss Factor Adjusted Price less than or equal to the Balancing Price, the minimum amount of sent out energy, in MWh, if any, which could have been dispatched in the Trading Interval from any of the Facility's Balancing Price-Quantity Pairs which have a Loss Factor Adjusted Price greater than the Balancing Price,~~

~~taking into account the Balancing Facility's SOI Quantity and Ramp Rate Limit;~~

~~(b) for a Balancing Facility which is a Non-Scheduled Generator:~~

~~i. if the Loss Factor Adjusted Price of the Balancing Price Quantity-Pair in respect of the Balancing Facility is less than or equal to the Balancing Price, then the Sent Out Metered Schedule as determined in accordance with clause 6.15.3(a)(i); and~~

~~ii. otherwise the minimum amount of sent out energy, in MWh, which the Balancing Facility could have generated in the Trading Interval if the Facility had been dispatched downwards at its Ramp Rate Limit from its SOI Quantity; or~~

~~(c) for the Verve Energy Balancing Portfolio:~~

~~i. the maximum amount of sent out energy, in MWh, which could have been dispatched in the Trading Interval from Balancing Price-Quantity Pairs within the Balancing Portfolio Supply Curve with an associated price less than or equal to the Balancing Price; plus~~

~~ii. if the Verve Energy Balancing Portfolio's SOI Quantity is greater than the sum of the quantities in the Balancing Price-Quantity Pairs within the Balancing Portfolio Supply Curve which have an associated price that is less than or equal to the Balancing Price, the minimum amount of sent out energy, in MWh, if any, which could have been dispatched in the Trading Interval from any of the Balancing Price-Quantity Pairs within the Balancing Portfolio Supply Curve which have an associated price greater than the Balancing Price,~~

~~taking into account the Portfolio Ramp Rate Limit and the SOI Quantity.~~

6.15.1. The IMO must calculate for each Facility and the Verve Energy Balancing Portfolio, and for each Trading Interval, the Maximum Theoretical Energy Schedule and Minimum Theoretical Energy Schedule:

(a) at the times specified in clause 6.15.3; and

(b) in accordance with the methodologies described in Appendix 11.

6.15.2. [Blank]~~The Minimum Theoretical Energy Schedule in a Trading Interval equals:~~

~~(a) for a Balancing Facility which is a Scheduled Generator, the amount which is the lesser of:~~

~~i. the sum of:~~

~~1. the maximum amount of sent out energy, in MWh, which could have been dispatched in the Trading Interval from Balancing Price-Quantity Pairs in respect of the Balancing Facility with a Loss Factor Adjusted Price less than the Balancing Price; plus~~

~~2. if the Facility's SOI Quantity is greater than the sum of the quantities in the Facility's Balancing Price-Quantity Pairs which have a Loss Factor Adjusted Price less than the Balancing Price, the minimum amount of sent out energy, in MWh, if any, which could have been dispatched in the Trading Interval from any of the Facility's Balancing Price-Quantity Pairs which have a Loss Factor Adjusted Price greater than or equal to the Balancing Price,~~

~~taking into account the Balancing Facility's SOI Quantity and Ramp Rate Limit; and~~

~~ii. where the Balancing Facility is subject to an Outage, the maximum amount of sent out energy, in MWh, which could have been dispatched given the Available Capacity for that Trading Interval;~~

~~(b) for a Balancing Facility which is a Non-Scheduled Generator:~~

~~i. if a Dispatch Instruction was issued to the Balancing Facility to decrease its output and the Loss Factor Adjusted Price of the Balancing Price-Quantity Pair in respect of the Balancing Facility is less than the Balancing Price, then System Management's estimate of the maximum amount of sent out energy, in MWh, which the Balancing Facility would have supplied in the Trading Interval had the Dispatch Instruction not been issued; and~~

~~ii. otherwise the Sent Out Metered Schedule for the Facility as determined in accordance with clause 6.15.3(a)(i); or~~

~~(c) for the Verve Energy Balancing Portfolio, the amount which is the lesser of:~~

~~i. the sum of:~~

~~1. the maximum amount of sent out energy, in MWh, which could have been dispatched in the Trading Interval from Balancing Price-Quantity Pairs within the Balancing Portfolio~~

~~Supply Curve with an associated price less than the Balancing Price; plus~~

~~2. if the Verve Energy Balancing Portfolio's SOI Quantity is greater than the sum of the quantities in the Balancing Price-Quantity Pairs within the Balancing Portfolio Supply Curve which have an associated price that is less than the Balancing Price, the minimum amount of sent out energy, in MWh, if any, which could have been dispatched in the Trading Interval from any of the Balancing Price-Quantity Pairs within the Balancing Portfolio Supply Curve which have an associated price greater than or equal to the Balancing Price,~~

~~taking into account the Portfolio Ramp Rate Limit and SOI Quantity; and~~

~~ii. where a Facility in the Verve Energy Balancing Portfolio is subject to an Outage, the maximum amount of sent out energy, in MWh, which could have been dispatched given the sum of the Available Capacity of Facilities in the Verve Energy Balancing Portfolio for that Trading Interval.~~

6.15.3<u>.</u> The IMO must:

(a) calculate Maximum Theoretical Energy Schedules ~~under clause 6.15.1~~ and Minimum Theoretical Energy Schedules ~~under clause 6.15.1:~~<u>as soon as practicable after receiving applicable SCADA data under clause 7.13.1(cA); and</u>

~~i. using Sent Out Metered Schedules determined using SCADA data and output estimates received from System Management in accordance with clause 7.13.1(cA), notwithstanding any requirement in clause 9.3.4 to use Meter Data Submissions received by the IMO; and~~

~~ii. as soon as practicable after receiving applicable SCADA data under clause 7.13.1(cA); and~~

(b) update Maximum Theoretical Energy Schedules and Minimum Theoretical Energy Schedules calculated under clause 6.15.3(a) as soon as practicable after receiving a relevant schedule of Outages under clause 7.13.1A(b).

6.15.4<u>.</u> The Maximum Theoretical Energy Schedules and Minimum Theoretical Energy Schedules calculated by the IMO in accordance with clause 6.15.3 cannot be altered by:

(a) disagreement under clause 9.20.6; or

(b) disputes under clause 9.21.1.

…

6.16A. ~~Facility~~ Out of Merit Generation

~~6.16A.1. The Upwards Out of Merit Generation in a Trading Interval for a Balancing Facility equals:~~

~~(a) subject to clause 6.16A.1(b), the Sent Out Metered Schedule less the Maximum Theoretical Energy Schedule; or~~

~~(b) zero where:~~

~~i. System Management has provided a report to the IMO under clause 7.10.7 and the IMO determines that the relevant Market Participant has not adequately or appropriately complied with a Dispatch Instruction;~~

~~ii. the Facility was undergoing a Test or complying with an Operating Instruction; or~~

~~iii. the Sent Out Metered Schedule less the Maximum Theoretical Energy Schedule is less than the sum of:~~

~~1. any Upwards LFAS Enablement and, if the Facility is a Stand Alone Facility, any Upwards Backup LFAS Enablement, which the Facility was instructed by System Management to provide, divided by two so that it is expressed in MWh; and~~

~~2. the applicable Settlement Tolerance.~~

6.16A.1. The IMO must calculate the Upwards Out of Merit Generation for a Facility or the Verve Energy Balancing Portfolio, as applicable, in accordance with the methodology described in Appendix 11 as soon as practicable after it:

(a) calculates the Maximum Theoretical Energy Schedule or the Minimum Theoretical Energy Schedule for that Facility or the Verve Energy Balancing Portfolio, as applicable, under clause 6.15.3(a); or

(b) updates the Maximum Theoretical Energy Schedule or the Minimum Theoretical Energy Schedule for that Facility or the Verve Energy Balancing Portfolio, as applicable, under clause 6.15.3(b).

~~6.16A.2. The Downwards Out of Merit Generation in a Trading Interval for a Balancing Facility equals:~~

~~(a) subject to clause 6.16A.2(b), the Minimum Theoretical Energy Schedule less the Sent Out Metered Schedule; or~~

~~(b) zero if:~~

~~i. System Management has provided a report to the IMO under clause 7.10.7 and the IMO determines that the relevant Market Participant has not adequately or appropriately complied with a Dispatch Instruction;~~

~~ii. the Facility was undergoing a Test or complying with an Operating Instruction;~~

~~iii. the Minimum Theoretical Energy Schedule less the Sent Out Metered Schedule is less than the sum of:~~

~~1. any Downwards LFAS Enablement and, if the Facility is a Stand Alone Facility, any Downwards Backup LFAS Enablement, which the Facility was instructed by System Management to provide, divided by two so that it is expressed in MWh; and~~

~~2. the applicable Settlement Tolerance; or~~

~~iv. the Balancing Facility is a Non-Scheduled Generator and System Management has not provided the IMO with a MWh quantity for the Facility and the Trading Interval under clause 7.13.1(eF).~~

6.16A.2. The IMO must calculate the Downwards Out of Merit Generation for a Facility or the Verve Energy Balancing Portfolio, as applicable, in accordance with the methodology described in Appendix 11 as soon as practicable after it:

(a) calculates the Maximum Theoretical Energy Schedule or the Minimum Theoretical Energy Schedule for that Facility or the Verve Energy Balancing Portfolio, as applicable, under clause 6.15.3(a); or

(b) updates Maximum Theoretical Energy Schedules and Minimum Theoretical Energy Schedules for that Facility or the Verve Energy Balancing Portfolio, as applicable, calculated under clause 6.15.3(b).

~~6.16B.1. The Portfolio Upwards Out of Merit Generation in a Trading Interval for the Verve Energy Balancing Portfolio equals:~~

~~(a) subject to clause 6.16B.1(b), the sum of any Sent Out Metered Schedules for Facilities in the Verve Energy Balancing Portfolio less the Maximum Theoretical Energy Schedule for the Verve Energy Balancing Portfolio; or~~

~~(b) zero if:~~

~~i. System Management has provided a report to the IMO under clause 7.10.7 and the IMO determines that Verve Energy has not adequately or appropriately complied with a Dispatch Order in respect of the Verve Energy Balancing Portfolio; or~~

~~ii. the sum of any Sent Out Metered Schedules for Facilities in the Verve Energy Balancing Portfolio less the Maximum Theoretical Energy Schedule for the Verve Energy Balancing Portfolio is less than the sum of:~~

~~1. any increase in sent out energy due to a Network Control Service Contract which System Management instructed a Facility within the Verve Energy Balancing Portfolio to provide;~~

~~2. if Facilities within the Verve Energy Balancing Portfolio were instructed by System Management to provide LFAS, the sum~~

~~of Upwards LFAS Enablement and Upwards LFAS Backup Enablement, both divided by two so that they are expressed in MWh;~~

~~3. if a Spinning Reserve Event has occurred, any Spinning Reserve Response Quantity; and~~

~~4. the Portfolio Settlement Tolerance.~~

~~6.16B. Verve Energy Balancing Portfolio Out of Merit~~

~~6.16B.2. The Portfolio Downwards Out of Merit Generation in a Trading Interval for the Verve Energy Balancing Portfolio equals:~~

~~(a) subject to clause 6.16B.2(b), the Minimum Theoretical Energy Schedule less the sum of any Sent Out Metered Schedules for Facilities in the Verve Energy Balancing Portfolio; or~~

~~(b) zero if:~~

~~i. System Management has provided a report to the IMO under clause 7.10.7 and the IMO determines that Verve Energy has not adequately or appropriately complied with a Dispatch Order; or~~

~~ii. the Minimum Theoretical Energy Schedule of the Verve Energy Balancing Portfolio less the sum of any Sent Out Metered Schedules for Facilities in the Verve Energy Balancing Portfolio is less than the sum of:~~

~~1. any reduction in sent out energy due to a Network Control Service Contract which System Management instructed a Facility within the Verve Energy Balancing Portfolio to provide;~~

~~2. if Facilities within the Verve Energy Balancing Portfolio were instructed by System Management to provide LFAS, the sum of the Downwards LFAS Enablement plus the Downwards LFAS Backup Enablement, both divided by two so that they are expressed in MWh;~~

~~3. if a Load Rejection Reserve Event has occurred, any Load Rejection Reserve Response Quantity; and~~

~~4. the Portfolio Settlement Tolerance.~~

…

Constrained On ~~Facility Balancing~~ Quantities and Prices

~~6.17.3. Subject to clauses 6.17.5B and 6.17.5C, the IMO must attribute any Upwards Out of Merit Generation from a Balancing Facility that is a Scheduled Generator in a Trading Interval, as follows:~~

~~(a) Constrained On Quantity1 (ConQ1) equals the lesser of:~~

~~i. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the Facility's Balancing Price-Quantity Pair N, with a Loss Factor Adjusted Price (Price N) higher than but closest to the Balancing Price, taking into account the actual SOI Quantity of the Balancing Facility and the applicable Ramp Rate Limit; and~~

~~ii. the Upwards Out of Merit Generation for the Balancing Facility;~~

~~(b) Constrained On Compensation Price1 (ConP1) equals the Loss Factor Adjusted Price N identified in clause 6.17.3(a) less the Balancing Price;~~

~~(c) If the Balancing Facility's Upwards Out of Merit Generation exceeds ConQ1 and a Balancing Price-Quantity Pair exists for the Facility and Trading Interval with a Loss Factor Adjusted Price higher than Price N, then:~~

~~i. additional Constrained On Quantity2 (ConQ2) equals the lesser of:~~

~~1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the Facility's Balancing Price-Quantity Pair N+1 with a Loss Factor Adjusted Price (Price N+1) higher than but closest to the Price N, taking into account when the Balancing Facility's MW level reached the top, or bottom, as applicable, of the quantity associated with the Balancing Price-Quantity Pair N in the calculation in clause 6.17.3(a)(i) and the applicable Ramp Rate Limit; and~~

~~2. the Upwards Out of Merit Generation for the Balancing Facility less ConQ1; and~~

~~ii. Constrained On Compensation Price2 (ConP2) equals the Loss Factor Adjusted Price N+1 identified in clause 6.17.3(c)(i) less the Balancing Price;~~

~~(d) The IMO must repeat the process set out in clause 6.17.3(c) to identify, from the next highest priced Price N+1, any ConQN+1 and ConPN+1 until all Upwards Out of Merit Generation has been attributed to Balancing Price-Quantity Pairs or, otherwise, until there are no remaining Balancing Price-Quantity Pairs;~~

~~(e) The Non-Qualifying Constrained On Generation for the Balancing Facility equals the sum, divided by two so that it is expressed as sent out MWh, of any Upwards LFAS Enablement and, if the Facility is a Stand Alone Facility, any Upwards LFAS Backup Enablement, which the Balancing Facility was instructed to provide by System Management;~~

~~(f) If:~~

~~i. the Non-Qualifying Constrained On Generation exceeds ConQ1, set ConQ1 to zero; or~~

ii. ~~otherwise reduce ConQ1 by the amount of Non-Qualifying Constrained On Generation;~~

(g) ~~The IMO must repeat the process set out in clause 6.17.3(f) for each ConQN in ascending order until all Non-Qualifying Constrained On Generation has been deducted from ConQN or, otherwise, until there are no remaining ConQN; and~~

(h) ~~For settlement purposes under Chapter 9, the IMO must Loss Factor adjust each ConQN calculated in clauses 6.17.3(a) to 6.17.3(f).~~

6.17.3. The IMO must attribute any Upwards Out of Merit Generation from a Balancing Facility and the Verve Energy Balancing Portfolio in a Trading Interval as soon as practicable after it calculates the Upwards Out of Merit Generation under clause 6.16A.1, and in accordance with the methodology for calculating Constrained On Quantities and Constrained On Compensation Prices described in Appendix 11.

~~6.17.3A Subject to clause 6.17.5B, for any Balancing Facility that is a Non-Scheduled Generator, in a Trading Interval:~~

(a) ~~ConQ1 equals the Upwards Out of Merit Generation, in MWh, for the Trading Interval, which for settlement purposes under Chapter 9 the IMO must Loss Factor adjust; and~~

(b) ~~ConP1 equals the greater of:~~

i. ~~zero; and~~

ii. ~~the Loss Factor Adjusted Price in the Balancing Price-Quantity Pair associated with the Balancing Facility for that Trading Interval less the Balancing Price for that Trading Interval.~~

~~6.17.4. Subject to clauses 6.17.5B and 6.17.5C, the IMO must attribute any Downwards Out of Merit Generation from a Balancing Facility that is a Scheduled Generator, in a Trading Interval, as follows:~~

(a) ~~Constrained Off Quantity1 (CoffQ1) equals the lesser of:~~

i. ~~the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from the Facility's Balancing Price-Quantity Pair N, with a Loss Factor Adjusted Price (Price N), taking into account the Available Capacity and actual SOI Quantity of the Balancing Facility and the applicable Ramp Rate Limit, where N is determined from either of the following Balancing Price-Quantity Pairs or, if different, the one with the lower price:~~

1. ~~the Balancing Price-Quantity Pair associated with the intersection of Available Capacity and the quantities in all Balancing Price-Quantity Pairs summed in order of lowest to highest price; and~~

~~2. the Balancing Price-Quantity Pair with a Loss Factor Adjusted Price lower than but closest to the Balancing Price; and~~

~~ii. the Downwards Out of Merit Generation for the Balancing Facility;~~

~~(b) Constrained Off Compensation Price1 (CoffP1) equals the Balancing Price less the Loss Factor Adjusted Price, Price N, identified in clause 6.17.4(a);~~

~~(c) If the Balancing Facility Downwards Out of Merit Generation exceeds CoffQ1 and a Balancing Price-Quantity Pair exists for the Facility and Trading Interval with a Loss Factor Adjusted Price lower than Price N, then:~~

~~i. additional Constrained Off Quantity2 (CoffQ2) equals the lesser of:~~

~~1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from the Facility's Balancing Price-Quantity Pair N+1 with a Loss Factor Adjusted Price (Price N+1) lower than but closest to the Price N, taking into account when the Balancing Facility's MW level reached the bottom, or the top, as applicable, of the quantity associated with the Balancing Price-Quantity Pair N in the calculation in clause 6.17.4(a)(i) and the applicable Ramp Rate Limit; and~~

~~2. the Downwards Out of Merit Generation for the Balancing Facility less CoffQ1; and~~

~~ii. Constrained Off Compensation Price2 (CoffP2) equals the Balancing Price less the Loss Factor Adjusted Price N+1 identified in clause 6.17.4(c)(i);~~

~~(d) The IMO must repeat the process set out in clause 6.17.4(c) to identify, from the next lowest priced Price N+1, any CoffQN+1 and CoffPN+1 until all Downwards Out of Merit Generation has been attributed to Balancing Price-Quantity Pairs or, otherwise, until there are no remaining Balancing Price-Quantity Pairs;~~

~~(e) The Non-Qualifying Constrained Off Generation for the Balancing Facility equals the sum, divided by two so that it is expressed as sent out MWh, of any Downwards LFAS Enablement and, if the Facility is a Stand Alone Facility, any Downwards Backup LFAS Enablement, which the Balancing Facility was instructed to provide by System Management;~~

~~(f) If:~~

~~i. the Non-Qualifying Constrained Off Generation exceeds CoffQ1, set CoffQ1 to zero; or~~

~~ii. otherwise reduce CoffQ1 by the amount of Non-Qualifying Constrained Off Generation;~~

~~(g) The IMO must repeat the process set out in clause 6.17.4(f) for each CoffQN in ascending order until all Non-Qualifying Constrained Off~~

~~Generation has been deducted from CoffQN or, otherwise, until there are no remaining CoffQN; and~~

~~(h) For settlement purposes under Chapter 9, the IMO must Loss Factor adjust each CoffQN calculated in clauses 6.17.4(a) to clauses 6.17.4(f).~~

Constrained Off ~~Facility Balancing~~ Quantities and Prices

<u>6.17.4. The IMO must attribute any Downwards Out of Merit Generation from a Balancing Facility and the Verve Energy Balancing Portfolio in a Trading Interval as soon as practicable after it calculates the Downwards Out of Merit Generation under clause 6.16A.2, and in accordance with the methodology for calculating Constrained Off Quantities and Constrained Off Compensation Prices described in Appendix 11.</u>

~~6.17.4A. Subject to clause 6.17.5B, for any Balancing Facility that is a Non-Scheduled Generator, in a Trading Interval:~~

~~(a) CoffQ1 equals the Downwards Out of Merit Generation, in MWh, for that Trading Interval, which for settlement purposes under Chapter 9 the IMO must Loss Factor adjust; and~~

~~(b) CoffP1 equals the Balancing Price for that Trading Interval less the Loss Factor Adjusted Price in the Balancing Price-Quantity Pair associated with the Balancing Facility for that Trading Interval.~~

~~**Constrained On Verve Energy Balancing Portfolio Quantities and Prices**~~

~~6.17.5. Subject to clause 6.17.5C, the IMO must attribute any Upwards Out of Merit Generation from the Verve Energy Balancing Portfolio in a Trading Interval as follows:~~

~~(a) Portfolio Constrained On Quantity1 (PConQ1) equals the lesser of:~~

~~i. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the Balancing Price-Quantity Pair N in the Balancing Portfolio Supply Curve with a price (Price N) higher than but closest to the Balancing Price, taking into account the actual Verve Energy Balancing Portfolio SOI Quantity and the Portfolio Ramp Rate Limit; and~~

~~ii. the Upwards Out of Merit Generation for the Verve Energy Balancing Portfolio;~~

~~(b) Constrained On Compensation Price1 (PConP1) equals the Price N identified in clause 6.17.5(a) less the Balancing Price;~~

~~(c) If the Portfolio Upwards Out of Merit Generation exceeds PConQ1 and a Balancing Price-Quantity Pair exists in the Balancing Portfolio Supply Curve with a price higher than Price N, then:~~

~~i. additional Portfolio Constrained On Quantity2 (PConQ2) equals the lesser of:~~

~~1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the Balancing Portfolio Supply Curve Balancing Price-Quantity Pair N+1 with a price (Price N+1) higher than but closest to the Price N, taking into account when the Verve Energy Balancing Portfolio MW level reached the top, or the bottom, as applicable, of Balancing Price-Quantity Pair N in the calculation in clause 6.17.5(a)(i) and the Portfolio Ramp Rate Limit; and~~

~~2. the Portfolio Upwards Out of Merit Generation less PConQ1; and~~

~~ii. Constrained On Compensation Price2 (PConP2) equals the Price N+1 identified in clause 6.17.5(c)(i) less the Balancing Price;~~

~~(d) The IMO must repeat the process set out in clause 6.17.5(c) to identify, from the next highest priced Balancing Price-Quantity Pair N+1, any PConQN+1 and PConPN+1 until all Upwards Out of Merit Generation has been attributed to Balancing Price-Quantity Pairs or, otherwise, until there are no remaining Balancing Price-Quantity Pairs in the Balancing Portfolio Supply Curve;~~

~~(e) The Non-Qualifying Constrained On Generation for the Verve Energy Balancing Portfolio equals the sum, expressed in sent out MWh, of any increase in energy due to a Network Control Service Contract and of the following Ancillary Services (if any), which System Management instructed Verve Energy to provide from Facilities within the Verve Energy Balancing Portfolio:~~

~~i. Upwards LFAS Enablement;~~

~~ii. Upwards LFAS Backup Enablement; and~~

~~iii. the Spinning Reserve Response Quantity;~~

~~(f) If:~~

~~i. the Non-Qualifying Constrained On Generation exceeds PConQ1, set PConQ1 to zero; or~~

~~ii. otherwise reduce PConQ1 by the amount of Non-Qualifying Constrained On Generation;~~

~~(g) The IMO must repeat the process set out in clause 6.17.5(f) for each PConQN in ascending order until all Non-Qualifying Constrained On Generation has been deducted from PConQN or otherwise until there are no remaining PConQN; and~~

~~(h) For settlement purposes under Chapter 9, each PConQN calculated in this clause 6.17.5 is to be Loss Factor adjusted by the Portfolio Loss Factor.~~

~~Constrained Off Verve Energy Balancing Portfolio Quantities and Prices~~

~~6.17.5A. Subject to clause 6.17.5C, the IMO must attribute any Downwards Out of Merit Generation from the Verve Energy Balancing Portfolio in a Trading Interval as follows:~~

~~(a) Constrained Off Portfolio Quantity1 (PCoffQ1) equals the lesser of:~~

~~i. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from Balancing Price-Quantity Pair N, with Price N, in the Balancing Portfolio Supply Curve, taking into account the Available Capacity of the Verve Energy Balancing Portfolio, the MW level at the start of the Trading Interval and the Portfolio Ramp Rate Limit, where N is determined from either of the following Balancing Price-Quantity Pairs or, if different, the one with the lower price:~~

~~1. the Balancing Price-Quantity Pair associated with the intersection of Available Capacity and the quantities in all Balancing Price-Quantity Pairs in the Balancing Portfolio Supply Curve summed in order of lowest to highest price; and~~

~~2. the Balancing Price-Quantity Pair with a price lower than but closest to the Balancing Price; and~~

~~ii. the Portfolio Downwards Out of Merit Generation;~~

~~(b) Portfolio Constrained Off Compensation Price1 (PCoffP1) equals the Balancing Price less the Price N identified in clause 6.17.5A(a);~~

~~(c) If the Portfolio Downwards Out of Merit Generation (in MWh) exceeds PCoffQ1 and a Balancing Price-Quantity Pair exists in the Balancing Portfolio Supply Curve with a price lower than Price N, then:~~

~~i. additional Constrained Off Portfolio Quantity2 (PCoffQ2) equals the lesser of:~~

~~1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from the Balancing Portfolio Supply Curve Balancing Price-Quantity Pair N+1 with a price (Price N+1) lower than but closest to Price N, taking into account when the Verve Energy Balancing Portfolio MW level reached the bottom, or top, as applicable, of Balancing Price-Quantity Pair N in the calculation in clause 6.17.5A(a)(i) and the Portfolio Ramp Rate Limit; and~~

~~2. the Portfolio Downwards Out of Merit Generation less PCoffQ1; and~~

~~ii. Portfolio Constrained Off Compensation Price2 (PCoffP2) equals the Balancing Price less the Price N+1 identified in clause 6.17.5A(c)(i);~~

~~(d) The IMO must repeat the process set out in clause 6.17.5A(c) to identify, from the next lowest priced Balancing Price-Quantity Pair N+1, any PCoffQN+1 and PCoffPN+1 until all Downwards Out of Merit Generation has been attributed to Balancing Price-Quantity Pairs or, otherwise, until there are no remaining Balancing Price-Quantity Pairs in the Balancing Portfolio Supply Curve;~~

~~(e) The Non-Qualifying Constrained Off Generation for the Verve Energy Balancing Portfolio equals the sum, expressed in sent out MWh, of any reduction in sent out energy due to a Network Control Service Contract and of the following Ancillary Services (if any), which System Management instructed Verve Energy to provide from Facilities in the Verve Energy Balancing Portfolio:~~

~~i. Downwards LFAS Enablement;~~

~~ii. Downwards LFAS Backup Enablement; and~~

~~iii. the Load Rejection Reserve Response Quantity ;~~

~~(f) If:~~

~~i. the Non-Qualifying Constrained Off Generation exceeds PCoffQ1 set PCoffQ1 to zero; or~~

~~ii. otherwise reduce PCoffQ1 by the amount of Non-Qualifying Constrained On Generation;~~

~~(g) The IMO must repeat the process set out in clause 6.17.5A(f) for each PCoffQN in ascending order until all Non-Qualifying Constrained Off Generation has been deducted from PCoffQN or there are no remaining PCoffQN; and~~

~~(h) For settlement purposes under Chapter 9, each PCoffQN calculated in this clause 6.17.5A is to be Loss Factor adjusted by the Portfolio Loss Factor.~~

Balancing Quantities and Prices Exceptions

~~6.17.5B. Clauses 6.17.3, 6.17.3A, 6.17.4 and 6.17.4A do not apply to Facilities in the Verve Energy Balancing Portfolio.~~

6.17.5~~C~~. Where the IMO is unable to attribute:

(a) Upwards Out of Merit Generation in accordance with clauses 6.17.3~~ or 6.17.5, as applicable:~~; or

(b) Downwards Out of Merit Generation in accordance with clauses 6.17.4~~ or 6.17.5A~~,

for a Market Participant, the Market Participant is not entitled to be paid for any Upwards Out of Merit Generation or Downwards Out of Merit Generation, as applicable.

…

7.7.5A. System Management must develop, in a Power System Operation Procedure, the information that must be provided by a Market Participant to System Management for each of the Market Participant's Non-Scheduled Generators for each Trading Interval to enable an estimation of the output of each Facility, in MWh, to be undertaken by:

(a) System Management, as required under clauses ~~6.15.2(b)(i),~~ 7.7.5B and 7.13.1C(e) and for the purposes of the calculation of the Minimum Theoretical Energy Schedule for a Non-Scheduled Generator under Appendix 11; and

(b) the IMO, as required by the Relevant Level Methodology.

7.7.5B. The quantity to be used ~~in clause 6.15.2(b)(i)~~ for the purposes of the calculation of the Minimum Theoretical Energy Schedule for a Non-Scheduled Generator under Appendix 11, is System Management's estimate, determined in accordance with the Power System Operation Procedure, of the maximum amount of sent out energy, in MWh, which each Non-Scheduled Generator, by Trading Interval, would have supplied in the Trading Interval had a Dispatch Instruction not been issued.

…

7.7.5D. System Management must provide the estimate required ~~under clause 6.15.2(b)(i)~~ for the purposes of the calculation of the Minimum Theoretical Energy Schedule for a Non-Scheduled Generator under Appendix 11 as soon as reasonably practicable but in any event in time for settlement under Chapter 9.

…

7.7.6B. If a Market Participant notifies System Management under clause 7.7.6(b) or clause 7.10.3 that it cannot fully comply with a Dispatch Instruction, then it must, at the same time, provide notice of:

(a) where the Market Participant can comply with the quantity required in the Dispatch Instruction but not the required ramp rate, the different ramp rate with which the Market Participant can comply; or

(b) where the Market Participant cannot comply with the quantity required in the Dispatch Instruction:

i. the reduced quantity (if any) and associated ramp rate with which the Market Participant can comply; and

ii whether the Market Participant needs to desynchronise the Facility in order to provide the reduced quantity,

and System Management must, subject to meeting the Dispatch Criteria, issue a ~~new~~ Rectification Dispatch Instruction or Operating Instruction, as applicable, to the Market Participant in accordance with the advice received.

…

7.13.1A. System Management must provide the IMO with the following data for a Trading Day by noon on the fifteenth Business Day following the day on which the Trading Day ends:

(a) the MWh quantity of non-compliance by Verve Energy by Trading Interval; and

(b) the schedule of all Planned Outages, Forced Outages and Consequential Outages relating to each Trading Interval in the Trading Day by Market Participant and Facility~~.~~as measured on a sent out basis at:

i. 15 degrees Celsius; and

ii. 41 degrees Celsius.

…

Glossary

~~**Constrained Off Compensation Price**: Has the meaning given in clause 6.17.4 and 6.17.4A.~~

Constrained Off Compensation Price: Means the price calculated under clause 6.17.4 and in accordance with Appendix 11.

~~**Constrained Off Quantity**: Has the meaning given in clause 6.17.4 and 6.17.4A.~~

Constrained Off Quantity: Means the quantity calculated under clause 6.17.4 and in accordance with Appendix 11.

~~**Constrained Off Portfolio Quantity**: Has the meaning given in clause 6.17.5A.~~

~~**Constrained On Compensation Price**: Has the meaning given in clause 6.17.3, 6.17.3A or clause 6.17.5,.~~

Constrained On Compensation Price: Means the price calculated under clause 6.17.3 and in accordance with Appendix 11.

~~**Constrained On Quantity**: Has the meaning given in clause 6.17.3 and 6.17.3A.~~

Constrained On Quantity: Means the quantity calculated under clause 6.17.3 and in accordance with Appendix 11.

…

~~**Equivalent Planned Outage Hours:** means, in respect of a Facility, the sum of the "Planned Outage Hours" and the "Equivalent Planned Derated Hours" for the Facility as calculated in accordance with the Power System Operation Procedure.~~

Equivalent Planned Outage Hours: Means the quantity calculated under clause 4.27.3 and in accordance with Appendix 10.

[Note: Drafting of 'Equivalent Planned Outage Hours' reflects proposed Amending Rules in the Draft Rule Change Report for RC_2013_09: Incentives to Approve Availability of Scheduled Generators]

…

Forced Outage: Has the meaning given in clause 3.21.~~1~~2B.

Forced Outage Rate: Means the rate calculated under clause 4.11.1(h) and in accordance with Appendix 10.

…

Maximum Theoretical Energy Schedule: Means the schedule ~~determined~~ calculated under clause 6.15.1 at the times specified in clause 6.15.3 and in accordance with Appendix 11.

…

Minimum Theoretical Energy Schedule: Means the schedule ~~determined~~ calculated under clause 6.15.~~2~~1 at the times specified in clause 6.15.3 and in accordance with Appendix 11.

…

Outage: ~~Means a Forced Outage, a Planned Outage or a Consequential Outage.~~Has the meaning given in clause 3.21.1.

…

Planned Outage Rate: Means the rate calculated under clause 4.11.1(h) and in accordance with Appendix 10.

…

Rectification Dispatch Instruction: Means a subsequent Dispatch Instruction issued by System Management to a Market Participant in accordance with clause 7.7.6B, following that Market Participant advising System Management of its inability to comply with a Dispatch Instruction in accordance with clause 7.7.6(b)(ii).

…

Appendix 10: Planned and Forced Outage Rate Determination

The IMO must calculate the Equivalent Planned Outage Hours, Planned Outage Rate and Forced Outage Rate for a Facility and a period of time (P) as follows.

The Equivalent Planned Outage Hours $(EPOH)$ for the Facility equals:

$$EPOH = 0.5 \times \sum_{t \in CO} \frac{PO(t)}{Cap(t)}$$

The Planned Outage Rate (POR) as a percentage for the Facility equals:

$$POR = \frac{1}{n}\sum_{t \in CO} \frac{PO(t)}{Cap(t)} \times 100$$

The Forced Outage Rate (FOR) as a percentage for the Facility equals:

$$FOR = \frac{1}{n}\sum_{t \in CO} \frac{FO(t)}{Cap(t)} \times 100$$

Where:

- CO is the set of Trading Intervals in period (P) for which the Facility has been in Commercial Operation, where t is used to refer to a member of that set;
- n is the number of Trading Intervals in period (P) for which the Facility has been in Commercial Operation;
- $PO(t)$ is the quantity of Planned Outage in MW for the Facility in Trading Interval t as calculated in accordance with clause 3.21.6(c) and:
  - o provided in accordance with clause 7.13.1A(b)(ii) if the Facility holds Capacity Credits and had its Certified Reserve Capacity assigned using the methodology described in clause 4.11.1(a), or
  - o provided in accordance with clause 7.13.1A(b)(i) otherwise;
- $FO(t)$ is the quantity of Forced Outage in MW for the Facility in Trading Interval t as calculated in accordance with clause 3.21.6(b) and:
  - o provided in accordance with clause 7.13.1A(b)(ii) if the Facility holds Capacity Credits and had its Certified Reserve Capacity assigned using the methodology described in clause 4.11.1(a), or
  - o provided in accordance with clause 7.13.1A(b)(i) otherwise; and
- $Cap(t)$ is the capacity for the Facility, given by
  - o the number of Capacity Credits held by the Facility in Trading Interval t if the Facility holds Capacity Credits and had its Certified Reserve Capacity assigned using the methodology described in clause 4.11.1(a), or
  - o the Sent Out Capacity of the Facility as recorded in Standing Data (Appendix 1(b)iii if the Facility is a Scheduled Generator and Appendix 1(e)(iiiA) if the Facility is a Non-Scheduled Generator) during Trading Interval t otherwise.

Appendix 11: Constrained On and Off Compensation Determination

This appendix provides the calculations necessary to determine the:

(a) Maximum Theoretical Energy Schedule;

(b) Minimum Theoretical Energy Schedule;

(c) Upwards Out of Merit Generation;

(d) Downwards Out of Merit Generation;

(e) Constrained On Quantity;

(f) Constrained On Compensation Price;

(g) Constrained Off Quantity; and

(h) Constrained Off Compensation Price.

Theoretical Energy Schedules

This section describes the method for determining the Maximum Theoretical Energy Schedule and Minimum Theoretical Energy Schedule in a Trading Interval for a Facility and the Verve Energy Balancing Portfolio.

The Maximum Theoretical Energy Schedule in a Trading Interval equals:

(a) For a Balancing Facility which is a Scheduled Generator and the Verve Energy Balancing Portfolio:

$$Max\ TES = (Max\ EOI \times 0.5) - \frac{\left((Max\ EOI - SOI\ Quantity) \times Ramp\ Duration\right)}{2}$$

Where:

$Max\ EOI$

$$= max\left(SOI\ Quantity - (Ramp\ Rate \times 30), min(SOI\ Quantity + (Ramp\ Rate \times 30), Max\ Gen\right)$$

$Max\ Gen = \sum BMO\ Quantities\ in\ MW$, for each tranche submitted where $BMO\ Price \leq Balancing\ Price;$

$$Ramp\ Duration = min\left(0.5, \left(\frac{|Max\ EOI - SOI\ Quantity|}{Ramp\ Rate/60}\right)\right)$$

$Ramp\ Duration$ - the duration which a Facility is expected to ramp, expressed as a proportion of an hour; and

$Ramp\ Rate$ – Facility or Portfolio Ramp Rate Limit expressed in MW per minute.

(b) For a Balancing Facility that is a Non-Scheduled Generator:

i. If $BMO\ Price\ \leq Balancing\ Price$, then:

$Max\ TES = Sent\ Out\ Metered\ Schedule$

ii. If $BMO\ Price\ > Balancing\ Price$, then:

$$Max\ TES = (Max\ EOI \times 0.5) - \frac{\big((Max\ EOI - SOI\ Quantity) \times Ramp\ Duration\big)}{2}$$

Where:

$Sent\ Out\ Metered\ Schedule$ – Sent out quantities provided by System Management in accordance with clause 6.15.3(a)(i);

$Max\ EOI = max\big(0, SOI\ Quantity - (Ramp\ Rate\ \times 30)\big)$

$$Ramp\ Duration = min\left(0.5, \left(\frac{|Max\ EOI - SOI\ Quantity|}{Ramp\ Rate/_{60}}\right)\right)$$

$Ramp\ Duration$ - the duration which a Facility is expected to ramp, expressed as a proportion of an hour; and

$Ramp\ Rate$ – Facility Ramp Rate Limit expressed in MW per minute.

The Minimum Theoretical Energy Schedule in a Trading Interval equals:

(a) For a Scheduled Generator and the Verve Energy Balancing Portfolio:

$$Min\ TES = min\left(Max\ Sent\ Out\ Energy, (Max\ EOI \times 0.5) - \frac{\big((Max\ EOI - SOI\ Quantity) \times Ramp\ Duration\big)}{2}\right)$$

Where:

$Max\ Sent\ Out\ Energy = max\ \ (0, Sent\ Out\ Capacity - Outage\ MW) \times 0.5;$

$Outage\ MW$ - Quantity of Outages in MW for the Facility or the Verve Energy Balancing Portfolio, as received from System Management in accordance with clause 7.13.1A(b)(i);

$$Max\ EOI = max\big(SOI\ Quantity - (Ramp\ Rate\ \times 30), min(SOI\ Quantity + (Ramp\ Rate\ \times 30), Max\ Gen\ Below\big)$$

$Max\ Gen\ Below = \sum BMO\ Quantities$, for each tranche submitted where BMO $Price\ < \ Balancing\ Price$;

$$Ramp\ Duration = \ min\left(0.5, \left(\frac{|Max\ EOI - SOI\ Quantity|}{Ramp\ Rate/_{60}}\right)\right)$$

$Ramp\ Duration$ - the duration which a Facility is expected to ramp, expressed as a proportion of an hour; and

$Ramp\ Rate$ – Facility or Portfolio Ramp Rate Limit expressed in MW per minute.

(b) for a Non-Scheduled Generator:

i. If the Non-Scheduled Generator has received a Dispatch Instruction to decrease its output and the Balancing Merit Order Price is less than the Balancing Price, then:

$Min\ TES\ = \ Sent\ Out\ Energy\ Estimate\ from\ System\ Management$; or

$$Min\ TES\ = \ Sent\ Out\ Metered\ Schedule$$

Where:

$Sent\ Out\ Energy\ Estimate\ from\ System\ Management$ - Estimate of sent out energy which would have been provided in Trading Interval had the Dispatch Instruction not been issued in accordance with clause 7.13.1(eF); and

$Sent\ Out\ Metered\ Schedule$ - Sent out quantities provided by System Management in accordance with clause 6.15.3(a)(i).

Out of Merit Generation

This section describes the method for determining the Out of Merit Generation in a Trading Interval for a Facility and the Verve Energy Balancing Portfolio.

The following definitions apply to the Out of Merit Generation calculations:

- $DI\ Quantity$ – The theoretical Dispatch Instruction Quantity which would have been provided in Trading Interval had the Facility complied with the Dispatch Instruction, with the exception of any Rectification Dispatch Instruction.
- $Max\ TES$ – Maximum Theoretical Energy Schedule.
- $NCS\ Increase$ – Any increase in sent out energy due to a Network Control Service Contract with System Management in MWh.
- $NCS\ Decrease$ – Any decrease in sent out energy due to a Network Control Service Contract with System Management in MWh.

The Upwards Out of Merit Generation in a Trading Interval equals:

(a) For a Balancing Facility other than the Verve Energy Balancing Portfolio:

$UOMG\ = \ min\ \ (Sent\ Out\ Metered\ Schedule, DI\ Quantity)\ - \ Max\ TES,$

except when:

i. the IMO has received a report under clause 7.10.7 and has determined that the relevant Market Participant has not adequately complied with a Dispatch Instruction; or

ii. the Facility was undergoing a Test of complying with an Operating Instruction; or

iii.

$$(Sent\ Out\ Metered\ Schedule - Max\ TES) < \left(\frac{Upwards\ LFAS\ Enablement + Backup\ Upwards\ LFAS\ Enablement}{2}\right) + Settlement\ Tolerance$$

; or

iv $Max\ TES\ >\ Sent\ Out\ Metered\ Schedule$,

where the Upwards Out of Merit Generation equals zero.

(b) For the Verve Balancing Energy Portfolio:

$PUOMG\ =\ Sent\ Out\ Metered\ Schedule - Max\ TES$, except when:

i System Management has provided a report to the IMO under clause 7.10.7 and the IMO determines that Verve Energy has not adequately or appropriately complied with a Dispatch Order in respect of the Verve Energy Balancing Portfolio; or

ii

$$(Sent\ Out\ Metered\ Schedule - Max\ TES) < NCS\ Increase + \left(\frac{Upwards\ LFAS\ Enablement + BackupUpwards\ LFAS\ Enablement}{2}\right) + Spinning\ Reserve\ Response\ Quantity + Portfolio\ Settlement\ Tolerance$$

where the Upwards Out of Merit Generation equals zero.

The Downwards Out of Merit Generation in a Trading Interval equals:

(a) For a Balancing Facility other than the Verve Energy Balancing Portfolio:

$DOMG = Min\ TES - max\ \ (Sent\ Out\ Metered\ Schedule, DI\ Quantity)$, except when:

i. the IMO has received a report under clause 7.10.7 and has determined that the relevant Market Participant has not adequately complied with a Dispatch Instruction; or

ii. the Facility was undergoing a Test of complying with an Operating Instruction; or

iii.

$$Min\ TES - Sent\ Out\ Metered\ Schedule\ < \left(\frac{Downward\ LFAS\ Enablement + Backup\ Downwards\ LFAS\ Enablement}{2}\right) + Settlement\ Tolerance$$

; or

iv. The Balancing Facility is a Non-Scheduled generator and System Management and System Management has not provided the IMO with a MWh quantity for the Facility for the Trading Interval under clause 7.13.1(eF); or

v. $Sent\ Out\ Metered\ Schedule\ >\ Min\ TES$,

where the Downwards Out of Merit Generation equals zero.

(b) For the Verve Energy Balancing Portfolio:

$PDOMG\ =\ Min\ TES - Sent\ Out\ Metered\ Schedule$, except when

i System Management has provided a report to the IMO under clause 7.10.7 and the IMO determines that Verve Energy has not adequately or appropriately complied with a Dispatch Order in respect of the Verve Energy Balancing Portfolio; or

ii

$$\begin{aligned}&\text{Min TES} - \text{Sent Out Metered Schedule}\\&< \text{NCS Decrease}\\&+ \left(\frac{\text{Downwards LFAS Enablement} + \text{Backup Downwards LFAS Enablement}}{2}\right)\\&+ \text{Load Rejection Reserve Quantity} + \text{Portfolio Settlement Tolerance}\end{aligned}$$

where the Upwards Out of Merit Generation equals zero.

where the Upwards Out of Merit Generation equals zero.

Constrained On Facility Balancing Quantities and Prices

This section describes the method for determining a facility's Constrained On Compensation Prices $ConP(n)$ and Quantities $ConQ(n)$ in a Trading Interval.

The following definitions apply to the Constrained On Compensation Prices and Quantities calculations:

- Price(n) – The Price associated with the Price Quantity Pair n.
- $NCS\ Increase$ – Any increase in sent out energy due to a Network Control Service Contract with System Management in MWh.

The Constrained On Compensation Prices and Quantities equal:

(a) For Scheduled Generators excluding Facilities within the Verve Energy Balancing Portfolio:

Step 1: Determine the amount of Non-Qualifying Constrained On Generation ($NQCon$) in MWh as:

$$NQCon\ =\ \frac{\text{Upwards LFAS Enablement}\ +\ \text{Upwards LFAS Backup Enablement}}{2}.$$

Step 2: For each Trading Interval, sort all Price Quantity Pairs for a Facility with a Loss Factor Adjusted Price higher than the Balancing Price in ascending order. The Price Quantity Pair with the lowest price will be referenced as Price Quantity Pair 1, and the next lowest price Price Quantity Pair 2 and so on, with the Price Quantity Pair with the highest price being Price Quantity Pair N.

Step 3: For each n from 1 to N, determine the maximum cumulative quantity up to Price Quantity Pair n, $CumQ(n)$, as the maximum cumulative MWh quantity that could have been dispatched within Price Quantity Pairs 1 to n, taking into account the actual SOI Quantity and the Ramp Rate Limit.

Step 4: For each n from 1 to N, determine the Constrained On Quantity for Price Quantity Pair n, $ConQ(n)$, as the quantity of the energy between $NQCon$ and $UOMG$ that would have been dispatched from Price Quantity Pair n if a total of $CumQ(n-1)$ was dispatched from Price Quantity Pairs 1 to $n-1$ and a total $CumQ(n)$ from Price Quantity Pairs 1 to n, which is given by:

$$ConQ(n) = \max\left(0, \min[UOMG, CumQ(n)] - \max[NQCon, CumQ(n-1)]\right),$$

where $CumQ(0)$ is defined to be zero.

Step 5: Loss factor adjust each $ConQ(n)$ value for Settlements purposes.

Step 6: Determine the Constrained Price for each Price Quantity Pair n as:

$$ConP(n) = \ Loss\ Factor\ Adjusted\ Price(n) - \ Balancing\ Price.$$

(b) For Non-Scheduled Generators excluding Facilities within the Verve Energy Balancing Portfolio:

Step 1: Constrained On Quantity

$$ConQ(n) = Upwards\ Out\ of\ Merit\ Generation\ in\ MWh$$

Step 2: Loss factor adjust each $ConQ(n)$ value for Settlements purposes.

Step 3: The Constrained On Price for each Price Quantity Pair N as:

$$ConP(n) = \ Loss\ Factor\ Adjusted\ Price(n) - \ Balancing\ Price.$$

(c) For the Verve Energy Balancing Portfolio:

Step 1: Determine the amount of Non-Qualifying Constrained On Generation ($NQCon$) in MWh as:

$$NQCon = \frac{Upwards\ LFAS\ Enablement\ +\ Upwards\ LFAS\ Backup\ Enablement}{2} + NCS\ Increase + Spinning\ Reserve\ Response\ Quantity.$$

Step 2: For each Trading Interval, sort all Price Quantity Pairs for the Verve Energy Balancing Portfolio, with a Loss Factor Adjusted Price higher than the Balancing Price in ascending order. The Price Quantity Pair with the lowest price will be referenced as Price Quantity Pair 1, and the next lowest price

Price Quantity Pair 2 and so on, with the Price Quantity Pair with the highest price being Price Quantity Pair N.

Step 3: For each n from 1 to N, determine the maximum cumulative quantity up to Price Quantity Pair n, $CumQ(n)$, as the maximum cumulative MWh quantity that could have been dispatched within Price Quantity Pairs 1 to n, taking into account the actual SOI Quantity and the Ramp Rate Limit.

Step 4: For each n from 1 to N, determine the Constrained On Quantity for Price Quantity Pair n, $PConQ(n)$, as the quantity of the energy between $NQCon$ and $PUOMG$ that would have been dispatched from Price Quantity Pair n if a total of $CumQ(n-1)$ was dispatched from Price Quantity Pairs 1 to $n-1$ and a total $CumQ(n)$ from Price Quantity Pairs 1 to n, which is given by:

$$PConQ(n) = max\left(0, min[PUOMG, CumQ(n)] - max[NQCon, CumQ(n-1)]\right),$$

where $CumQ(0)$ is defined to be zero.

Step 5: Loss factor adjust each $PConQ(n)$ value for Settlements purposes.

Step 6: Determine the Constrained Price for each Price Quantity Pair n as:

$$PConP(n) = \ Price\ Quantity\ Pair\ Price(n) – \ Balancing\ Price.$$

Constrained Off Facility Balancing Quantities and Prices

This section describes the method for determining a facility's Constrained Off Prices $(\mathrm{CoffP(n)})$ and Quantities $(\mathrm{CoffQ(n)})$ in a Trading Interval.

The following definitions apply to the Constrained Off Prices and Quantities calculations:

- Price(n) – The Price associated with the Price Quantity Pair n.
- $NCS\ Decrease$ – Any decrease in sent out energy due to a Network Control Service Contract with System Management.

The Constrained On Compensation Prices and Quantities equal:

(a) For Scheduled Generators excluding facilities within the Verve Energy Balancing Portfolio:

Step 1: Determine the amount of Non-Qualifying Constrained Off Generation ($NQCoff$) in MWh as:

$$NQCoff = \frac{Downwards\ LFAS\ Enablement\ +\ Downwards\ LFAS\ Backup\ Enablement}{2}.$$

Step 2: For each Trading Interval, sort all Price Quantity Pairs for a Facility with a Loss Factor Adjusted Price lower than the Balancing Price in descending order. The Price Quantity Pair with the highest price will be referenced as Price Quantity Pair 1, and the next highest price Price Quantity Pair 2 and so on, with the Price Quantity Pair with the lowest price being Price Quantity Pair N.

Step 3: If the sum up the quantities of the Price Quantity Pairs from 1 to N is greater than the Available Capacity of the Facility, then the intersection of the sorted Price Quantity Pairs defined in Step 1 and the Available Capacity will be referenced as Price Quantity Pair 1, and the next highest price Price Quantity Pair 2 and so on, with the Price Quantity Pair with the lowest price being Price Quantity Pair N.

Step 4: For each n from 1 to N, determine the maximum cumulative quantity up to Price Quantity Pair n, $CumQ(n)$, as the maximum cumulative MWh quantity that could have been dispatched within Price Quantity Pairs 1 to n, taking into account the actual SOI Quantity and the Ramp Rate Limit.

Step 5: For each n from 1 to N, determine the Constrained Off Quantity for Price Quantity Pair n, $CoffQ(n)$, as the quantity of the energy between $NQCoff$ and $DOMG$ that would have been dispatched from Price Quantity Pair n if a total of $CumQ(n-1)$ was dispatched from Price Quantity Pairs 1 to $n-1$ and a total $CumQ(n)$ from Price Quantity Pairs 1 to n, which is given by:

$$CoffQ(n) = max\left(0, min[DOMG, CumQ(n)] - max[NQCoff, CumQ(n-1)]\right),$$

where $CumQ(0)$ is defined to be zero.

Step 6: Loss factor adjust each $CoffQ(n)$ value for Settlements purposes.

Step 7: Determine the Constrained Price for each Price Quantity Pair n as:

$$CoffP(n) = Balancing\ Price - Loss\ Factor\ Adjusted\ Price(n).$$

(b) For Non-Scheduled Generators excluding facilities within the Verve Energy Balancing Portfolio:

Step 1: Constrained Off Quantity

$$CoffQ(n) = Downwards\ Out\ Of\ Merit\ Generation\ in\ MWh$$

Step 2: Loss factor adjust each $CoffQ(n)$ value for Settlements purposes.

Step 3: The Constrained Off Price for each Price Quantity Pair N as:

$$CoffP(n) = Balancing\ Price - Loss\ Factor\ Adjusted\ Price(n).$$

(c) For the Verve Energy Balancing Portfolio:

Step 1: Determine the amount of Non-Qualifying Constrained Off Generation ($NQCoff$) in MWh as:

$$NQCoff = \frac{Downwards\ LFAS\ Enablement + Downwards\ LFAS\ Backup\ Enablement}{2} + NCS\ Decrease + Load\ Rejection\ Reserve\ Response\ Quantity.$$

Step 2: For each Trading Interval, sort all Price Quantity Pairs for the Verve Energy Balancing Portfolio with a Loss Factor Adjusted Price lower than the

Balancing Price in descending order. The Price Quantity Pair with the highest price will be referenced as Price Quantity Pair 1, and the next highest price Price Quantity Pair 2 and so on, with the Price Quantity Pair with the lowest price being Price Quantity Pair N.

Step 3: If the sum up the quantities of the Price Quantity Pairs from 1 to N is greater than the Available Capacity of the Verve Energy Balancing Portfolio, then the intersection of the sorted Price Quantity Pairs defined in Step 1 and the Available Capacity will be referenced as Price Quantity Pair 1, and the next highest price Price Quantity Pair 2 and so on, with the Price Quantity Pair with the lowest price being Price Quantity Pair N.

Step 4: For each n from 1 to N, determine the maximum cumulative quantity up to Price Quantity Pair n, $CumQ(n)$, as the maximum cumulative MWh quantity that could have been dispatched within Price Quantity Pairs 1 to n, taking into account the actual SOI Quantity and the Ramp Rate Limit.

Step 5: For each n from 1 to N, determine the Constrained Off Quantity for Price Quantity Pair n, $PCoffQ(n)$, as the quantity of the energy between $NQCoff$ and $PDOMG$ that would have been dispatched from Price Quantity Pair n if a total of $CumQ(n-1)$ was dispatched from Price Quantity Pairs 1 to $n-1$ and a total $CumQ(n)$ from Price Quantity Pairs 1 to n, which is given by:

$$PCoffQ(n) = max\left(0, min[PDOMG, CumQ(n)] - max[NQCoff, CumQ(n-1)]\right),$$

where $CumQ(0)$ is defined to be zero.

Step 6: Loss factor adjust each $PCoffQ(n)$ value for Settlements purposes.

Step 7: Determine the Constrained Price for each Price Quantity Pair n as:

$$PCoffP(n) = Balancing\ Price - Price\ Quantity\ Pair\ Price(n).$$

…

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

The IMO considers that the Market Rules as a whole, if amended to reflect the recommendations above, will not only be consistent with the Wholesale Market Objectives but also generally allow the Market Rules to better achieve Wholesale Market Objectives (a), (c) and (d).

The proposed Amending Rules are designed to align the treatment of Scheduled Generators and Non-Scheduled Generators as far as practicable with respect to availability, Outages and constraint payments. On this basis, the IMO's assessment is presented below:

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

The IMO considers that the proposed changes will ensure that all limitations on a Facility's capacity to generate will be more accurately reflected in a Facility's Minimum TES, thereby improving the accuracy of constrained off compensation and the assignment of Certified Reserve Capacity to Facilities. This will ensure that significant costs as a result of inaccurate compensation payments are not borne by the market.

In addition, the advanced notification of Consequential Outages will provide greater transparency to Market Participants and will thereby improve the accuracy of the Balancing Price Forecast.

The IMO considers that the proposed amendments also provide greater clarity and transparency with respect to existing obligations in the Market Rules. This will better equip Market Participants to comply with their obligations.

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*

The proposed changes are expected to improve consistency between Scheduled and Non-Scheduled Generators, by providing alternative calculations for Non-Scheduled Generators, consistent with the obligations on Scheduled Generators. In addition, the IMO considers that the resulting clarity around Non-Scheduled Generators' obligations will improve the ability for the IMO to avoid discrimination between Facility Classes, for example in certification and compliance activities.

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

Currently, a significant proportion of the IMO's legal and compliance resources are spent investigating the merit of compensation payments and ensuring the recovery of incorrect payments. However, the proposed amendments will ensure that the majority of these incorrect payments are not made in the initial settlement process, thereby removing the need for many of these investigations, reducing the long-term compliance cost to the IMO, as well as avoiding potential increases in prudential obligations.

The IMO considers that the proposed amendments are consistent with the remaining Objectives.

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

The financial cost of the proposed amendments for the market as a whole is expected to be significant and includes:

- for the IMO, approximately $190,000 of costs associated with system and IT changes to allow the transfer of additional Outage information from System Management to the IMO, calculation of each Facility's Dispatch Schedule to determine TES and the testing of the integrity of amended equations for settlement purposes;
- for System Management, approximately $239,000 of costs associated with system changes to allow logging of Outages after the 15 day timeframes, the provision of Outage data by Facility, by Trading Interval on a sent out basis at 15 degrees Celsius and the addition of a rectification Dispatch Instruction flag to signal non-compliance. This includes around $55,000 for System Management to transfer the capability and functionality to retain and distribute Dispatch Instructions and produce compliance analysis reports from the current system (SMITTS) to the new system (SMARTS); and

- reporting costs for Market Participants are not expected to change as a result of the proposed Amending Rules, as it is anticipated that a compliant operator would already be logging the information under the current Market Rules.

It is difficult to quantify the economic benefits that accrue from an improvement in the accuracy of settlements, invoicing and the certification of capacity. However, the market is likely to experience a net economic benefit as a result of:

- reduced IMO legal, financial and compliance costs associated with rectification of incorrect constraint compensation paid to Market Participants;
- greater certainty for Market Participants around the application of the Market Rules to Non-Scheduled Generators which will ensure investment and operational decisions are better informed and therefore less likely to lead to inefficient outcomes;
- more accurate invoicing, removing the need for both the IMO and Market Participants to monitor and rectify over payments through the settlement adjustment process; and
- the improved ability for the Market Rules to be practically applied, resulting in more efficient behaviours.

Wholesale Electricity Market
Concept Paper Proposal

Concept Paper Proposal ID: **CP_2013_13**
Date received: **TBA**

Concept requested by:

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Date submitted:	*28th October 2013*
Urgency:	*2*
Concept proposal title:	Market Fees - Payable based on Energy and Capacity
Market Rule(s) affected:	Primarily 2.24 & 9.13

Introduction

The purpose of a Concept Paper Proposal 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: Group Manager, Development and Capacity
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax: (08) 9254 4339
Email: market.development@imowa.com.au

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):

Combined market fees (IMO, System Management and ERA) will have risen ~250% in 8 years from ~$12.1M in 2007/08 to a forecast ~$31M in 2015/16 (ERA Allowable Revenue Determinations March 2013 plus Regulator Fees).

The costs of operating the market (recovered via the Allowable Revenue provisions) which are determined as Market Fees, System Operation Fees, and Regulator Fees, are currently recovered from market participants on an "**energy**" (only) basis.

The WA WEM however has distinct a *Capacity* Market and *Energy* market, each with clearly delineated rules, processes and commodities. Each market has administration, processes, functions, compliance obligations and systems which can generally be delineated as pertaining to one or both of these markets:

At a high level we could consider the following components as directly "Capacity" related:

- There is a complex Capacity Certification process involving forecasting, reporting, technical testing and participant certification.
- There are annual capacity tests for all DSM and generation sites.
- Certified capacity credits exist as a commodity and are bilaterally tradable. Market rules and systems exist to support these functions.
- Capacity compliance functions and process: eg. RCOQ obligations, reporting of capacity components, making capacity available to the energy market (ie. in STEM and Balancing)
- Complicated capacity related settlements mechanisms
  - o Capacity refund mechanisms calculated and settled on an interval to interval basis, not unlike energy.
  - o Furthermore, the actual capacity refund factor itself is to be calculated on a dynamic basis (interval-to-interval) if soon to be proposed rule changes progress as expected.
- System Management has real time, and medium & long term margin and capacity planning

functions and systems.

- Significant and peripheral capacity related market rules evolve as often as any other part of the market rules and recently a capacity related working group was formed and administered over 12 months. The rule changes flowing from that group are still progressing.

- Large processes such as the annual Statement of Opportunity and the ERA's annual assessment of the functioning of the WEM are often predicated on Capacity issues requiring a significant investment of regulatory time and resources to complete.

- System security, often the guide to significant decisions (eg. The granting of outages) are related typically involve a test of current and forecast capacity margins.

- Capacity processes are more complex, incorporate greater uncertainty, and take longer to reach resolution than energy solutions (which are often simply "price x quantity" processes).

An additional underlying issue is that a participant may have Certified Reserve Capacity (CRC) yet may not in fact have any (or minimal) energy associated with that capacity. The result is that a participant may draw significant revenue from the WA WEM without paying associated costs. Instead, the total cost is levied to energy end-users, regardless of whether or not those users derive any utility from all of the capacity on the system. Capacity is a bilaterally tradeable commodity (perhaps forming part of the fixed price, or capital cost recovery, components of such a contract) and as such there is a means of cost recovery to the provider if there is a willing off taker for their product.

Capacity related costs for these three services are a material component of the total costs. Analysis of the IMO's market fees shows that approximately 27% of total costs are directly related to the Capacity Market. Brief conversations with the ERA and System Management to gauge their estimation of capacity related costs to perform their functions, have been answered with estimates in the range of 25% to 30% of total costs.

In summary, Bluewaters believes the fact that recovery of the aggregate cost of operating the two markets being focused only on energy production and consumption is inappropriate, inefficient and inequitable.

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

Bluewaters believes reform of the cost recovery mechanism is one of a range of efficiency improvements the MAC could consider as it aims to achieve Market Objective D ("… minimise the long-term cost of electricity supplied to customers from the South West interconnected system…").

The objective of this concept paper (and subsequent rule change proposal) is to more appropriately align the recovery of market costs with manner those costs are incurred. That alignment will inherently provide a more efficient outcome for end use customers.

If it is acknowledged (by the IMO, System Management and the ERA) that an average of overall costs of ~27.2% is attributable to a "capacity" component, this suggests that ~$8.4M per annum is not being recovered from the appropriate stream. The reasoning for 27.2% is explained later.

As market reform aims to achieve more efficient outcomes there is scope to correct a clear and material inequity (in the manner that the costs of operating the markets are currently levied) which should be reviewed and improved as soon as possible.

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

Bluewaters Power would like the MAC and IMO to consider the concept of a change in the method that the IMO collects market fees. This concept paper proposes that the Market Rules be amended to allow Market Fees, System Operation Fees, and Regulator Fees to be split, by a reasonable estimation of their relatedness to the Capacity and Energy markets, and recovered from market participants in a similar basis.

As such, this paper proposes that market costs should be recovered on an **energy and capacity** basis. Customer consumption (PMSQ) & IRCR for retailers, and from Capacity providers based on energy generated (MSQ) and certified reserve capacity credits (CRC).

To remove confusion about the intent of this concept paper the following points summarise the intended outcome of these proposed changes to the Market Rules.

1. The market rules continue to require the cost of administering the Market to be determined (and therefore applicable allowable revenue) for Market Costs, Operator Costs and Regulator Costs.
    a. Initially, for the 2013-2013AR period (when 1b below can be implemented) an agreed reasonable percentage of 27.2% of total costs to be recovered via the capacity allocation.

       It may be reasonable to recommend that the IMO, System Management and the ERA provide their own assessment of the percentage of cost attributable to "capacity" and a volume weighted percentage be agreed until the next AR period whereby an agreed process can be implemented thereafter.
    b. For the next AR period, in some manner, to be determined, the Market Rules should require each component cost (Market Costs, Operator Costs and Regulator Costs) to reasonably identify the capacity and energy portion as a percentage, or as an absolute total dollar value – which will then be inserted into the Determination of Market Fees per annum.
2. Effectively the Energy component (proposed here as 72.8% of the total cost of administering the market) is charged to participants in the same manner it is currently – on a 'per MWh' basis of generation and consumption.
3. The remaining costs – the Capacity component of administering the market, is split equally on a per MW basis across the pool of Certified Reserve Capacity and IRCR.

In addition to the current fee rates defined in the market rules additional "energy" fee rates for each should be incorporated into the rules.

Section 2.24 "Determination of Market Fees" of the market rules should be updated to cater for the proposal outlined above.

Section 9.13 "The Market Participant Fee Settlement Calculations for a Trading Month" of the market rules contains the formula's used to allocate costs to market participants. This section of the market rules should be updated to reflect the additional elements of capacity cost items multiplied by the participant's IRCR and certified reserve capacity

Appendix 2 restates MR 2.22 Determination of the IMO's budget. The appendix suggests that System Planning costs, divided by the sum of System Planning and Market Operations 27.2%. This percentage could reasonably be used as the proxy for determining the percentage of Market Admin costs which may be allocated to Capacity related issues.

If the ERA and System Management maintain that ~25% to 30% of their costs are capacity related the 27.2% could be applied across the board for the 2013-2016 AR period. Subsequent AR periods may require the ERA and IMO to provide statements of the percentage of costs for that AR period which are capacity related. Those costs can then be carried forward to the calculation of applicable fee rates.

Appendix 1: Summary of IMO and System Management Allowable Revenue Fees

Cost of IMO and System Management (f = forecast)

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13 (f)	2013/14 (f)	2014/15 (f)	2015/16 (f)
System Management	$3,688	$5,084	$4,766	$5,504	$6,688	$9,472	$12,559	$13,200	$13,647
ERA (*estimated*)						$1,500	$1,538	$1,576	$1,615
IMO	$8,432	$11,125	$11,429	$11,803	$13,048	$16,055	$15,825	$16,265	$16,686
Total	$12,120	$16,209	$16,195	$17,307	$19,736	$27,027	$29,922	$31,041	$31,948

Appendix 2: IMO Fees - Capacity & Energy Split Proposal

2.22. Determination of the IMO's budget

2.22.1. For the purposes of this clause 2.22, the services provided by the IMO are:

(a) market operation services, including the IMO's operation of the Reserve Capacity market, STEM and Balancing and the IMO's settlement and information release functions;

(b) system planning services, including the IMO's performance of the Long Term PASA function; and

(c) market administration services, including the IMO's performance of the Market Rule change process, Market Procedure change process, the operation of the Market Advisory Committee and other consultation, monitoring, enforcement, audit, registration related functions and other functions under these Market Rules.

Determination of IMO's Capacity Component

Based on rounded figures from the IMO's Allowable Revenue Determination for the Financial Year 2015/16, the split of costs between IMO functions is:

- System Planning: $3,000,000
- Market Operations: $8,000,000
- Market Admin: $5,500,000

Total Costs: $16,500,000

$$Capacity\ Component\ Amount =$$

$$\left(\left(\frac{Annual\ System\ Planning\ Services}{(Annual\ System\ Planning\ Services + Annual\ Market\ Operation\ Services\ )}\right) \times Annual\ Market\ Admin\ Services\right) + Annual\ System\ Planning\ Services$$

Therefore the Energy component of IMO Market Fees = Annual Allowable Revenue – Capacity Component Amount

This would result in a split of fees for Capacity and Energy components as follows:

Capacity **(27.2%):** $4.5 = \left(\left(\frac{3}{(3+8\ )}\right) \times 5.5\right) + 3$

Energy **(72.8%)**: $12 = 16.5 - 4.5$

NB: This split is relatively consistent with other years in the Allowable Revenue period.

INDEPENDENT MARKET OPERATOR

Agenda Item 7a: Overview of Recent and Upcoming IMO and System Management Procedure Change Proposals

Legend:

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

ID	Summary of Changes	Status	Next Step	Date
IMO Procedure Change Proposals				
PC_2012_11 **Notices and Communications**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project. • Reflect the IMO's updated contact details.	• PC_2012_11: Notices and Communications was published on 18 June 2013.	• Submissions closed on 16 July 2013. The IMO is currently preparing the Procedure Change Report.	TBA
PC_2013_02: **Participant Registration and Deregistration**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Revise the Market Procedure to provide more details of the relevant processes, including restructuring the Market Procedure to better present the process; • Reflect the new MPR system;	• The IMO published the Procedure Change Report for PC_2013_02: Participant Registration and Deregistration was published on 30 October 2013.		

ID	Summary of Changes	Status	Next Step	Date
	• Ensure consistency with the Amending Rules from the Rule Change Proposal: Change of Review Board Name (RC_2010_18)	• The IMO commenced the revised Market Procedure on 1 November 2013.		
PC_2013_03 **Facility Registration, Deregistration and Transfer**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Reflect the new MPR system; • Revise the Market Procedure to provide more details of the relevant processes including: o restructuring the Market Procedure to better present the process; o providing further details of the consultation processes with System Management; o clarifying that there should not be any restriction on the ability to provide notifications in a manner outlined in the Market Procedure for Notifications and Communications; and o reflect the new processes for digital certificates • Ensure consistency with the Amending Rules from the following Rule Change Proposals; o Curtailable Loads and Demand Side Programmes (RC_2010_29); and o Change of Review Board Name (RC_2010_18), Including the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10)	• The IMO published the Procedure Change Report for PC_2013_03: Facility Registration, Deregistration and Transfer was published on 30 October 2013. • The IMO commenced the revised Market Procedure on 1 November 2013.		
PC_2013_04 **Prudential**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project;	• The IMO rejected this Rule Change Proposal on 19 November 2012.	• Changes arising from submissions on RC_2012_23 have been	15/11/13

ID	Summary of Changes	Status	Next Step	Date
Requirements	• Move more of the prescriptive detail from the Market Rules to the Procedure to make the rules more principles-based; • Include some minor and typographical amendments to improve the integrity of the Market Procedure; and • Include amendments required as a result of the Pre Rule Change Proposals: o Prudential Requirements (RC_2012_23); o Acceptable Credit Criteria (RC_2010_36); and o Removal of Network Control Services Expression of Interest and Tender Process (RC_2010_11).	• Modified Rule Change Proposal and updated Market Procedure presented to the March 2013 MAC. • Procedure Change Proposal and updated Procedure was submitted to 20 September 2013 IMOPWG.	incorporated together with IMOPWG feedback and will be re-circulated to IMOPWG members for comment prior to being formally submitted into the process.	
PC_2013_05 Reserve Capacity Security	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Revise the Market Procedure to provide more details of the relevant processes; • Include some minor and typographical amendments to improve the integrity of the Market Procedure; and • Include amendments required as a result of the Pre Rule Change Proposal: Prudential Requirements (PRC_2012_23).	• Procedure has been updated following the discussion on Prudentials at the 20 September 2013 IMOPWG.	• Updated Market Procedure to be circulated to the IMOPWG together with PC_2013_04 for comment prior to being formally submitted into the process.	15/11/13
PC_2013_06 **Certification of Reserve Capacity**	The proposed updates are to: • Reflect the revised consideration of outages in the assessment of applications for Certified Reserve Capacity, including; o new outage rates scale in table form; and o addition of IMO discretions and report requests; • Reflect the IMO's new format; • Explain the IMO discretion to assign a level of Reserve Capacity less than full; • Refine the assessment of fuel and other restrictions by the IMO;	• Underway	• Updated Market Procedure presented at 20 September IMOPWG. Updated Procedure to be re-circulated to IMOPWG members.	15/11/13

ID	Summary of Changes	Status	Next Step	Date
	• Outline the proposed changes to the Availability Classes; and • Reflect the treatment of Facilities that share a Declared Sent Out Capacity.			
PC_2013_07 **Settlement**	The proposed updates are to: • Reflect the necessary changes arising from RC_2013_08: Market Participant Fees - Clarification of GST Treatment; • Reflect the IMO's new format; • Provide greater clarity to potential and existing Rule Participants on the settlement process by improving the information provided around: o STEM and Non-STEM settlement processes and timelines; o Adjustment processes and timelines; o Process for settlement of the market in case of default situations; o Invoicing and the application of GST and interest to settlement transactions; and o Disagreement and dispute processes and timelines; • Improve the structure of the Procedure; and • Define new terms.	• Underway.	• Updated Market Procedure and Procedure Change Proposal to be published.	15/11/13
PC_2013_09 **Reserve Capacity Performance Monitoring**	The proposed updates are to: • Reflect the additional performance monitoring steps proposed in RC_2013_09; • Reflect the IMO's new format; • Remove steps made redundant by deleted clauses; and • Describe the new performance reports that may be requested by the IMO, including; o performance improvement reports; and	• Underway.	• Updated Market Procedure presented at 20 September IMOPWG. Updated Procedure to be re-circulated to IMOPWG members.	15/11/13

ID	Summary of Changes	Status	Next Step	Date
	o the format of reports.			
TBC **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).	• As advised at the August 2012 working group meeting, the IMO is currently undertaking the five yearly review of the IMO's forecasting processes. Following the completion of the review the IMO may make further changes to the Market Procedure.	• Updated procedure to be presented back to the Working Group for discussion	TBA
TBC **Meter Data Submission**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Clarify that the Procedure is part of the Settlement Market Procedures; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by the IMO Procedures Working Group	TBA
TBC **Capacity Credit Allocation**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Clarify that the Procedure is part of the Settlement Market Procedures; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Intermittent Load**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures	• Underway.	• To be discussed by IMO Procedures	TBA

ID	Summary of Changes	Status	Next Step	Date
Refund	project; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start		Working Group	
TBC **Individual Reserve Capacity Requirements**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Treatment of Small Generators**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with amendments to the Market Rules which have occurred since Market Start	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Reserve Capacity Testing**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Reflect the new Temperature Dependence Curve • Ensure consistency with the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10)	• Underway.	• To be discussed by IMO Procedures Working Group	TBA
TBC **Information Confidentiality**	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Ensure consistency with the proposed Amending Rules under the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10) along with all other rule changes which have occurred since Market Start.	• Underway.	• To be discussed by IMO Procedures Working Group	TBA

ID	Summary of Changes	Status	Next Step	Date
System Management Procedure Change Proposals				
PPCL0025 **Commissioning and Testing**	The proposed updates are to: • Include amendments required as a result of RC_2012_12 and RC_2012_15; • Expand Appendix C to clarify Load Following and Spinning Reserve requirements around commissioning inline with the Ancillary Services Report; and • Include 'plus ramp range' in Load Following for Maximum Ramp Rate tests.	• PPCL0025: Commissioning and Testing was published on 28 June 2013. Submissions closed on 26 July 2013.	• System Management are currently preparing the Procedure Change Report.	TBA
PPCL0026 **Facility Outages**	The proposed updates are to: • Reflect the new outage transparency rules resulting from RC_2012_11.	• Draft amended PSOP was circulated to the System Management PSOP WG for comment. The IMO provided feedback on 31 July 2013.	• System Management are updating the Procedure to reflect feedback received prior to re-circulating to WG members.	TBA
PPCL0027 **Dispatch**	The proposed updates are to: • Reflect the updated commitment/de-commitment rules resulting from RC_2012_22.	• PPCL0027 was initially submitted to the IMO to be put into the formal process. The IMO provided feedback to System Management on 6 August 2013 and discussed at the PSOP WG on 14 August 2013. Subsequently the PSOP change was withdrawn to be updated based on IMO feedback and re-circulated to WG	• System Management are updating the Procedure to reflect feedback received prior to re-circulating to WG members.	TBA

ID	Summary of Changes	Status	Next Step	Date
		members.		

Agenda Item 8a: Working Group Overview

Working Group (WG)	Status	Date commenced	Date concluded	Latest meeting date	Next scheduled meeting date
System Management Procedures WG	Active	Jul 07	Ongoing	14/08/2013	TBA
IMO Procedures WG	Active	Dec 07	Ongoing	20/09/2013	TBA