Independent Market Operator

Market Advisory Committee

Agenda

Meeting No.	34
Location:	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Wednesday 15 December 2010
Time:	2.00 – 5.00pm

Item	Subject	Responsible	Time
1.	**WELCOME**	**Chair**	5 min
2.	**MEETING APOLOGIES / ATTENDANCE**	**Chair**	
3.	**MINUTES OF PREVIOUS MEETING**	**Chair**	5 min
4.	**ACTIONS ARISING**	**Chair**	
5.	**MARKET RULES**		
	a) Market Rule Change Overview	**IMO**	2 min
	b) PRC_2010_30: Limits to Early entry capacity payments	**Alinta**	15 min
	c) PRC_2010_33: System Restart Costs	**Verve**	15 min
	d) Calculation of capacity value for Intermittent Generators (RC_2010_25 & RC_2010_37)	**IMO and Griffin**	15 min
6.	**MARKET PROCEDURES**		
	a) Overview	**IMO**	5 min
	b) SRC Market Procedure	**IMO**	5 min
7.	**WORKING GROUPS**		

Item	Subject	Responsible	Time
	a) Overview and membership updates	**IMO**	2 min
	b) MRCPWG Update	**IMO**	10 min
	c) RDIWG Update (verbal update following 14 December 2010 meeting)	**IMO**	10 min
8.	**LOAD FOLLOWING ANCILLARY SERVICES**	**SM**	45 min
9.	**RESERVE CAPACITY MECHANISM (presentation)**	**IMO**	45 min
10.	**2010 YEAR IN REVIEW**	**IMO**	15 min
11.	**GENERAL BUSINESS**		
12.	**NEXT MEETING: 9 February 2010**		

Independent Market Operator

Market Advisory Committee

Minutes

Meeting No.	33
Location:	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Wednesday 10 November 2010
Time:	Commencing at 12:00 pm

Attendees	**Class**	**Comment**
Allan Dawson	Chair	
Troy Forward	Compulsory – IMO	(12:00-4.45pm)
Jacinda Papps	Compulsory - IMO	Proxy (4.45-5.15pm)
Stephen MacLean	Compulsory – Customer	
Phil Kelloway	Compulsory – System Management	Proxy
Andrew Everett	Compulsory – Generator	
Peter Mattner	Compulsory – Network Operator	
Corey Dykstra	Discretionary – Customer	
Steve Gould	Discretionary – Customer	(12:00-5:10pm)
Peter Huxtable	Discretionary – Contestable Customer Representative	
Andrew Sutherland	Discretionary – Generator	
Shane Cremin	Discretionary – Generator	
Chris Brown	Observer – ERA	
Michael Kerr	Small Use Consumer Representative	
Nerea Ugarte	Minister's appointee - Observer	
Apologies	**Class**	**Comment**
Ken Brown	Compulsory – System Management	
Also in attendance	**From**	**Comment**
Fiona Edmonds	IMO	Minutes
Jenny Laidlaw	IMO	Minutes
Toby Stevenson	LECG	Presenter via teleconference (12:30-1:05pm)
Jenny Riesz	ROAM Consulting	Presenter
Jacinda Papps	IMO	Presenter (12:00-4.45pm)
Ben Williams	IMO	Presenter
Greg Ruthven	IMO	Observer
Courtney Roberts	IMO	Observer
Shannon Turner	IMO	Observer
Pablo Campillos	DMT Energy	Observer
Michael Zammit	Energy Response	Observer
Alistair Craib	Colgar Windfarm	Observer via teleconference
Chin Koay	Verve Energy	Observer

Item	Subject	Action
1.	**WELCOME** The Chair opened the meeting at 12.00am and welcomed members to the 33rd meeting of the Market Advisory Committee (MAC). The Chair apologised for the large agenda but noted his appreciation of the time that both the IMO and Market Participants had dedicated to the streams of work under discussion over the last few months. The Chair specifically acknowledged the contribution of REGWG members over the past year. The Chair stated that most of the issues on the agenda for discussion had been presented previously in other forums and that his preference was for the MAC to not re-litigate previous decisions. The Chair acknowledged that while that papers presented today would have strong commercial impacts the MAC was required to work in the best interests of the market, as specified in the MAC Constitution. Members would be provided an opportunity to express their company's commercial positions through the Rule Change Process. The MAC needs to provide leadership for the market on these difficult strategic issues.	
2.	**MEETING APOLOGIES / ATTENDANCE** An apology was received from Ken Brown. The Chair noted that the IMO has just been advised that Mr Michael Kerr and Ms Nerea Ugarte had been appointed by the Minister as the representative for Small Use Consumers and as the Minister's appointee respectively. The following other attendees were noted: • Jenny Reisz (Presenter) • Toby Stevenson (Presenter) • Shannon Turner (Observer) • Pablo Campillos (Observer) • Chin Koay (Observer) • Phil Kelloway (proxy for Ken Brown) • Ben Williams (Presenter) • Jacinda Papps (Presenter) • Courtney Roberts (Observer) • Greg Ruthven (Observer) • Alistair Craib (Observer) - phone • Michael Zammit (Observer)	
3	**MINUTES OF PREVIOUS MEETING** The minutes of MAC Meeting No. 32, held on 13 October 2010, were circulated prior to the meeting. Ms Ugarte suggested the following amendment: *<u>Page 6: Section 5b: Removal of NCS Procurement from the Market Rules [PRC_2010_11]</u>*	

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	• " The ~~Electricity Industry Amendments Act~~ Energy Legislation Amendments Bill is currently…" The following amendments were suggested by Mr Peter Huxtable: *Page 8: Section 5c: Updates to Certification of Reserve Capacity [PRC_2010_14]* • "Mr Peter Huxtable questioned the IMO's view on the request from participants for details of new large loads to be included in the load forecasts, particularly with regard to commercial-in-confidence issues" *Page 16: Section 5h: Limits to Early Entry Capacity Payments [PRC_2010_30]* • "ambient argument" should read "ambit claim" Mr Phil Kelloway suggested the following additional amendments: *Page 11: Section 5e: Providing Price Related Standing Data to System Management [PRC_2010_12]* • "...at this stage System Management does not use any pricing information but the recent discussions ~~of~~ on NCS, Ancillary Services, and Balancing (RDIWG) have indicated that System Management's role may change ..." *Page 12: Section 5e: Providing Price Related Standing Data to System Management [PRC_2010_12]* • "Mr Kelloway noted that System Management would require adequate time ~~to investigate~~ for investigations of incidences of Consequential Outage (both full and partial) to take place." *Page 17: Section 5h: Limits to Early Entry Capacity Payments [PRC_2010_30]* • "Mr Kelloway however noted that System Management ~~have~~ had had ~~very~~ little experience with dispatching DSM due to the restrictions that have applied to past DSM options." Mr Pablo Campillos also suggested the following amendment: *Page 17: Section 5h: Limits to Early Entry Capacity Payments [PRC_2010_30]* • "~~Does not r~~Recognises that the early entry…." Mr Kelloway also suggested some typographical amendments which were adopted by the IMO. Subject to the agreed amendments, the MAC endorsed the minutes as a	

Item	Subject	Action
	true and accurate record of the meeting. *Action Point: The IMO to amend the minutes of Meeting No. 32 to reflect the points raised by the MAC and publish on the website as final.*	**IMO**
4	**ACTIONS ARISING** The actions arising were either complete or on the meeting agenda. The following exceptions were noted: **Item 62:** Mr Stephen MacLean questioned if there was a requirement for the letter to the Minister to be sent at the same time as the Rule Change Proposal: Curtailable Loads and Demand Side Programmes (RC_2010_29) being progressed through the formal Rule Change Process. Mr Troy Forward noted that this was not necessary, but made more sense. **Item 78:** Mr Kelloway noted that System Management had been preparing its proposal to implement a competitive Ancillary Services market in conjunction with a number of Market Participants. A presentation on the proposed solution will be made at both the next Rules Development Implementation Working Group (RDIWG) meeting and the December 2010 MAC meeting. A discussion paper will subsequently be prepared and distributed by System Management. Mr Forward noted that the RDIWG is considering adjusting significant aspects of the market, for example introducing greater competition around Balancing, and that any change to Ancillary Services would need to be considered together with the changes to Balancing. There would otherwise be a risk of divergent market structures being implemented. Mr Kelloway noted the importance of progressing the implementation of a competitive Ancillary Services market, noting a preference that this should not be held up if there is a delay in the RDIWG process. Mr Corey Dykstra requested that the MAC meeting for the December meeting be moved to 15 December (currently scheduled for 8 December). *Action Point: The IMO to canvass the views of MAC members on moving the date for the next MAC meeting to 15 December 2010.* **Item 124:** Mr Forward noted that the MAC was required to reconfirm its advice to extend RC_2010_24: Adjustment of Relevant Level for Intermittent Generators contingent on the outcomes of any Rule Change Proposal relating to Work Package 2. Mr Dykstra sought to clarify whether the process for RC_2010_24 would be to publish a Final Rule Change Report containing Amending Rules and that these would simply be over written prior to commencement of any Amending Rules resulting from Work Package 2 (RC_2010_25). Mr Forward agreed noting the commencement date would be 1 July 2011, which would allow for the new methodology to be taken into account during the next certification process. **Item 132:** Mrs Jacinda Papps noted that the IMO's settlements team had reviewed the concept of providing provisional invoices to Market Participants and considered it feasible. Mrs Papps noted that the IMO was seeking the views of the MAC on the importance of progressing further with this concept.	**IMO**

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	The MAC agreed that further consideration of the concept of providing provisional invoices was not currently a priority, however the MAC discussed Market Participant's providing their own estimates for the IMO to confirm when it undertakes its first settlement run. Mr Forward noted that this was an option but that the process could be complex and time consuming. The IMO agreed to adopt the process of reviewing Market Participants' estimates as an interim working model. *Action Point: The IMO to adjust its operational practice to include reviewing Market Participants' estimates of their first settlement invoices, where appropriate.*	**IMO**
5	**RATIONALISATION OF THE INFORMATION CONFIDENTIALITY STATUS CLASSES IN THE WEM** Mr Forward noted that at the November 2009 MAC meeting Pacific Hydro had presented on the concept of introducing greater availability of market data in the WEM. Following this presentation the IMO embarked on a significant review of information confidentiality. The IMO engaged Law and Economics Consulting Group (LECG) to review the confidentiality status classes in the Market Rules with a view to rationalisation. When undertaking its assessment LECG had regard to the guiding principles for the provision of information in the market. That is, the IMO is to maximise the number of parties that may view any information or documents, subject to the information not containing commercially sensitive or potentially defamatory information in relation to a particular Rule Participant (clause 10.2.3). The Chair noted that timely information helps to make markets more efficient and access to an appropriate level of information is important. The Chair stated that the current Market Rules are restrictive in nature, noting a recent example of an unintentional breach of the Market Rules by providing aggregate level information on payments for Ancillary Services to an external party. Mr Toby Stevenson from LECG presented via teleconference an overview of the outcomes of its assessment. A copy of the presentation is attached as Appendix 1. The following points were raised: • Mr Dykstra questioned how the recommended arrangements would overlay with the current arrangements. Mrs Papps noted that there would be a reclassification exercise undertaken by the IMO of each type of market related information or document produced. • Mr Andrew Everett questioned if LECG had considered the basis for the current confidentiality arrangements in the WEM. Mr Stevenson responded that the current arrangements were developed early in the market and were likely driven by a concern that the release of information could impact on Market Participants' commercial interests. Mr Stevenson clarified that LECG does not consider that the complexity of the current arrangements is warranted. • Dr Steve Gould questioned whether there would be any merit in	

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	including a third category of confidential information for information that is separately classified in the Market Rules (section 4.1 of LECG's report). Mr Stevenson agreed that this variant could be adopted, noting that it would require the IMO to undertake an exercise to determine what information should be included and further consider how this category would be maintained. Mr Shane Cremin questioned if sub-clauses 10.2.3 (c) and (d) would cover this, noting that how and when this information is made available is of greater importance. Mr Forward clarified with Mr Cremin that the immediate availability of information for use by Market Participants would be beneficial. • It was agreed that more information should be available for immediate use to assist in day ahead trading decisions and two and a half year ahead Reserve Capacity decisions. Mr Sutherland noted that currently there was a week's delay in the publication of STEM bids and offers, which impacts on the ability of Market Participants to use this information and undertake operational forecasts. Mr Stevenson noted that in the New Zealand market this information was originally made available a month after the event, causing issues for participants and resulting in a number of appeals. Following further consideration this information is now made available on the following day. Mr Stevenson noted that during this process, participants' views about whether the commercial risk of being compromised by the release of the information would be outweighed by the market benefits changed. The Chair noted that aggregating information may maintain greater confidentiality levels and avoid potential pitfalls. The Chair noted that concerns about STEM bids and offers becoming available earlier could be overcome by making available an anonymous bid and offer stack to provide an opportunity for Market Participants to use these for their operational forecasting. • Mr Cremin noted that Market Participants may make different operating decisions if they have greater visibility of operational information, for example what type of facilities will be on planned outages. Mr Kelloway noted that there is a cost associated with the provision of information which needs to be recognised. Mr Dykstra noted that as a general principle the MAC seemed to be agreeing with the proposal, but noted that the IMO would need to manage participants' expectations around what information should be made available and when. Mr Forward noted that accepting this as a recommendation would initiate the next step in the process towards greater transparency. • Mr Dykstra suggested that sub-clause 10.2.3 (g) should actually be 10.2.3 (a) as this is the most important aspect of the decision making process. • Mr Kelloway noted that there may be a danger in moving towards a more simplified process, noting that the rationale for the move was unclear. The Chair noted that at market start a number of unnecessarily complex processes were incorporated into the Market Rules to counter perceived risks many of which were not realised.	

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	• Mrs Papps noted that the IMO would prepare a Pre Rule Change Discussion Paper which would include full Amending Rules. Mrs Papps noted that the IMO intended to consult directly with Market Participants on the reclassification of information into the proposed confidentiality classes. • Mr Kelloway noted that System Management is also a governance participant. The Chair apologised for the oversight and agreed that the IMO would request LECG to clarify this in the report. *Action Point: The IMO to request LECG to update the Confidentiality Status Classes in the WEM report to reflect System Management's position as a governance participant in the WEM.* *Action Point: The IMO to prepare a Pre Rule Change Discussion Paper to implement the proposed changes to the confidentiality status classes which contains the full Amending Rules and present back to the MAC for further discussion.*	**IMO** **IMO**
6a	**WORKING GROUP OVERVIEW** The MAC noted the Working Group overview and agreed to the proposed change to the System Management Procedure Change and Development Working Group membership. *Action Point: The IMO to update the terms of reference for the System Management Procedure Change and Development Working Group to reflect the agreed change in membership.*	**IMO**
6b	**MRCPWG UPDATE** The MAC noted the Maximum Reserve Capacity Price (MRCP) Working Group update	
6c	**REGWG FINAL REPORT** Mr Forward noted that the REGWG's Terms of Reference required a final report for the MAC on the outcomes of its work. Mr Forward noted that the aim of the final report was to capture the context and history of the REGWG, noting that there is likely to be rigorous discussion around the Rule Change Proposals resulting from the work undertaken by the REGWG. Mr Dykstra noted that the report had not been endorsed by the REGWG and so suggested that the reference to the report being "from the REGWG" be removed and replaced with a reference to the report having been prepared by the IMO. The other REGWG members present at the MAC meeting agreed. Mr Dykstra also noted there are some references to the development of Pre Rule Change Discussion Papers in the report which should be removed as they are not related to the outcomes of the REGWG. The REGWG members present at the MAC meeting agreed that the REGWG Final Report provided a reasonable reflection of the outcomes of the REGWG's deliberations. Mr Huxtable noted that the acronyms contained in the report should be provided in full as currently the report could not be read as a stand alone document. The IMO agreed to review the report and update accordingly.	

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	Action Point: Members to provide the IMO with any specific comments on the REGWG Final Report by 3 December 2010.	**MAC**
	Action Point: The IMO to update the REGWG Final Report to: • *reflect comments received from MAC members;* • *remove references to Pre Rule Change Discussion Paper's being developed by the IMO; and* • *include an explanation of any acronyms used in the report; and.* • *note that the report had been prepared by the IMO.*	**IMO**
6d	**RDIWG UPDATE** Mr Forward noted that during the last RDIWG meeting there had been a shift towards the solution phase for the Balancing issues. The RDIWG will continue discussing the issues identified around the timing of the STEM and capacity refunds at the next meeting. The Chair noted that the suggested changes to the Scheduling Day timeline seem to be problematic. As a result, the RDIWG may need to reconsider this proposal. The Chair stated the RDIWG is making good progress at addressing the issues, noting that a workshop with all of industry will be held shortly. Mr MacLean noted that a broader review of the Reserve Capacity Mechanism (RCM) is required opposed to just reviewing refunds. Mr Forward noted that the IMO had presented a timeframe for progressing the Market Rules Evolution Plan 18 months ago which included a review of the RCM commencing mid 2011. The IMO's preference would be to maintain the agreed schedule and to undertake a more thorough consideration of the RCM after the RDIWG review had been completed. The Chair noted that this review would constitute a large piece of work and questioned if the MAC would like to incorporate this into the work being undertaken by the RDIWG or else form a separate Working Group to consider this further. Mr MacLean noted that if a full review of the RCM was not started until next year then another Capacity Year would pass before any amendments are implemented. Mr Dykstra noted that there is a lot of focus on generation and in particular encouraging greater efficiency. Mr Dykstra stated that a review of the RCM would impact directly on consumption. Mr Cremin stated the current timelines for reviewing the RCM were appropriate, noting that serious consideration of the treatment of capacity from different types of providers and the interaction with the market objectives will be required. The Chair noted that the IMO Board had requested the IMO to undertake an internal review of the RCM and agreed that the IMO would present details of its recent presentation to the Board to the MAC.	
	Action Point: The IMO to present its recent Board presentation on the RCM at the December MAC meeting.	**IMO**

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	Mr Dykstra noted that realistically if a review of the RCM commenced now, a quick solution would be unlikely. Mr MacLean noted that the end user is currently encountering a cost associated with excess capacity which needs to be addressed. Mr MacLean encouraged the IMO to re-prioritise the review of the RCM higher on its list, in preference to looking solely at capacity refunds. Mr Forward noted that if this review is brought forward, something else would need to drop off the current work plan. Mr Forward requested suggestions for projects that could be delayed to undertake such a review. MAC members did not identify any projects that could be delayed. Mr MacLean noted that customers are concerned with how capacity is currently priced as it is not open to competition and so the price is high and the volume excessive. Mr Dykstra agreed that it might be time to review the MRCP, noting that the MRCPWG had agreed that it was outside the scope of its review to consider the use of the MRCP in the market (refunds for example). The MAC needs to consider these issues with some urgency given the recent experience with supply/demand balance not being consistent with an efficient market outcome. Mr Forward noted that the IMO agreed and had raised this with its Board.	
7a	**MARKET RULE CHANGE OVERVIEW** The MAC noted the overview of the Market Rule Changes.	
7b	**PARTIAL COMMISSIONING FOR INTERMITTENT GENERATORS [PRC_2010_22]** Mr Forward noted that the Pre Rule Change Discussion Paper proposes to introduce the concept of partial commissioning of Intermittent Generators for the purposes of Capacity Cost Refunds. Mr Forward noted that this would ensure that the value of the capacity delivered by these facilities to the market is better reflected (promoting Market Objective (c)). Scheduled Generators can currently take a commercial position of entering the market and for purposes of Reserve Capacity log partial outages, thereby avoiding full capacity refunds. Mr Forward noted that the proposal does not include the provision of an expert's report, as agreed by the MAC for the purposes of the return of Reserve Capacity Security (RC_2010_12). The following points were raised during the discussion. • Mr MacLean questioned why the IMO had decided to use the second highest value of output for the Facility. Mr Ben Williams clarified that this would be consistent with the need to meet requirements for two Trading Intervals for the return of RCS. • Mr Dykstra noted that this proposal would open all Intermittent Generators up to capacity refunds even if they have developed everything they had indicated in their certification application. Mr Dykstra noted that inclusion of an ability to provide an expert report to the IMO would avoid this issue. Mr Dykstra noted that otherwise an additional cost would be effectively imposed on a Market Generator if it does not meet 100 percent of its Required Level. Mr Dykstra noted that the practical outworking of this would be that the majority of participants would provide the IMO with an expert report to reduce their risks, and that this raises the question of what the proposal would achieve in	

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	practice. • Mr Alistair Craib noted that the rationale behind the proposed rule change is that currently a generator needs to be fully commissioned to avoid Capacity Cost Refunds. As a result, if they did not manage to bring on all their turbines they would be unduly impacted by paying back to the market the full amount of their Capacity Credits. Mr Forward noted that a thermal plant that was not 100 percent commissioned (e.g. if one of its four mills not operating) might be able to achieve 70 percent of output whereas a Intermittent Generator would be penalised for the whole amount of its capacity not being available. The proposed amendments will create a similar type of regime where if commissioning had not been completely successful there would be a point in time where the Market Participant would be relieved from full exposure to capacity refunds. Mr Dykstra clarified that the commissioning provisions are different for a thermal plant under the Market Rules. • Mr Cremin questioned if an Intermittent Generator can state that it has completed commissioning and then register a partial outage. Mr Williams noted that this was not currently an option for an Intermittent Generator. Mr Cremin questioned if this would be an easier option. Mr Williams noted that he did not consider that this would be the case. • Mr Sutherland noted that the proposed amendments would improve the consistency with the treatment of Scheduled Generators. • Mr MacLean suggested that brackets be included around the 2 and the Max_2 in the equation for determining the amount of refund that would be required in these circumstances. Additionally, Mr MacLean suggested that the IMO clarify that the "level of output" would be achieved during a Trading Interval during the Trading Month. Mr Forward agreed. The MAC agreed for the IMO to progress the Rule Change Proposal, subject to the incorporation of the agreed amendments. *Action Point: The IMO to update the Rule Change Proposal: Partial Commissioning for Intermittent Generators (RC_2010_22) to:* • *clarify that the Max_2 variable is based on the "…second highest level of output achieved <u>during a Trading Interval</u> during the Trading Month…"* • *include brackets around the "2 × Max_2" in the formula; and* • *reflect the ability for a Market Participant to provide the IMO with an expert report attesting that the Facility has been built in accordance with its certification specifications.* *Action Point: The IMO to progress RC_2010_22 through the Rule Change Process, subject to the incorporation of the agreed amendments.*	**IMO** **IMO**
7c	**CALCULATION OF THE CAPACITY VALUE OF INTERMITTENT GENERATION (WORK PACKAGE 2) [PRC_2010_25]** Mr Forward noted that the Pre Rule Change Discussion Paper proposes to implement Proposal 1 from the REGWG's Work Package 2. Mr Forward noted that there were likely to be competing views on the IMO's proposal as there had been neither a compromise nor consensus regarding a potential solution at the REGWG. The Chair noted that the issues around the	

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	valuation of capacity from Intermittent Generators had been discussed at many levels, noting the large amount of work done by the REGWG. The following points were raised during the meeting: • Mr MacLean noted that the REGWG had not agreed for a Rule Change Proposal to be developed at this stage. Mr Dykstra noted that it was agreed that the IMO would present a recommendation to the MAC for discussion. Mr Cremin said that the recommendation to progress the proposed solution is not appropriate at this point in time. Dr Gould disagreed stating that he had anticipated that a Rule Change Proposal would be presented to the MAC. Mr Forward clarified that the minutes from the RDIWG reflected the agreement that IMO would present a solution to the MAC for consideration, noting that a Pre Rule Change Discussion Paper is not inconsistent with this. Mr Forward noted that the recommendation presented in the cover paper was intended to represent the fact that the IMO considered it would be unlikely that consensus would be achieved at the MAC. Mr Dykstra stated that the IMO should be more mindful to not imply that a decision had already been made. Mr Everett disagreed that this was an issue. • Mr Cremin questioned the imperative to push forward with a proposal given the polarised opinion on what capacity valuation methodology should be adopted. Mr Dykstra noted that further consideration of any movement from the status quo is required. • Mr Dykstra questioned what the deficiencies were in McLennan Magasanik Associates (MMA's) proposed approach. Mr Forward noted that there was a shortage of data and that System Management had a serious concern about system security under the outcomes of MMA's proposed methodology. Mr Kelloway noted that this had been discussed in detail at REGWG meetings. Dr Gould noted System Management's concern had been with Capacity Credits being allocated at greater than 20 percent of nameplate capacity as this would not represent the capacity that could be made available reliably. Mr MacLean thought that System Management had some concern about wind farms not performing. Mr Dykstra stated that the available data set had generated certain results and other than "gut feelings" about appropriate valuation levels there was no reason to not adopt MMA's approach. Mr Kelloway clarified that System Management had undertaken its own assessment which had informed its position on this. Mr Dykstra noted that the intent of the RCM is to ensure sufficient energy as well as sufficient peak capacity. Mr Cremin noted that if an Intermittent Generator was to be unavailable during peak periods the methodology presented by MMA would take this into account in assigning Capacity Credits to the facility. Mr Forward clarified that under MMA's proposed methodology the Facility's availability would be determined based on 750 Trading Intervals. • The Chair noted that the data set used does not include a one in ten year event and the lack of core data around these extreme events has had a powerful influence on the IMO's considerations. • Mr Dykstra noted that the analysis undertaken by ROAM Consulting (ROAM) around the capacity for Load Following services indicates that there is enough plant on the system to deal with a greater penetration	

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	of Intermittent Generators. Mr Kelloway noted that the mix of plant on the system has an impact on whether this is the case. Mr Kelloway noted that if the value of Intermittent Generators overstates their ability to deliver then System Management will not be able to ensure that the available supply of energy can meet peak demand. • Mr Dykstra noted that after MMA had delivered its original report significant discussions on the proposal had been held among the IMO, System Management and the Office of Energy (OoE), and yet MMA was not persuaded to move away from its proposed solution. Mr Forward noted that MMA had no experience in operating a power system. Mr Dykstra considered that this may encourage MMA to take a more conservative approach. • Mr Dykstra suggested that from a system security and reliability perspective System Management would prefer to have a situation of no Intermittent Generation on the system. Mr Kelloway responded that this would not be in the best interests of the market. • The Chair noted that it is difficult to ignore the system operator when it notes that there may be potential impacts on system security. The Chair noted that during the discussions at the REGWG System Management had moved towards the less conservative proposal. • Mr MacLean noted that the MMA's proposed methodology, which was based on system security and reliability criteria, was being rejected in favour of an arbitrary alternative approach. • Mr Cremin noted that at one of the first REGWG meetings chaired by the IMO, Ms Anne Hill had noted the OoE's position as being conservative on this issue. Mr Cremin noted that this position had no regard for the Market Objectives and appeared to be politically motivated. Mr Cremin noted that the proposal would need to meet the Market Objectives if it was progressed, and that the IMO would have to take into account any comments raised in submissions. Mr Cremin considered that to contradict MMA's recommendation would require strong justification. Ms Ugarte clarified that Ms Hill's view had related to the security of supply. Mr Cremin noted that previous statements from the OoE around encouraging renewable energy sources is at odds with the Minister's previous advice to the MAC that only commercial incentives should be taken into account. • Mr Cremin questioned why there was the need to change the current commercial mechanisms when it is in fact the reliability criteria that should be reviewed. Mr Forward questioned who should bear the costs of changes to the reliability criteria. Mr Cremin considered that end users should bear the costs of using an ineffective generation source. • Mr Dykstra noted the volatility of the results from Proposals 1 and 3 over time, noting that investors would be unlikely to enter the market with such volatile potential Capacity Credit allocations. Mr Dykstra stated that the 3 year averaging approach currently provides a much smoother option, as does MMA's proposed solution. • Mr Dykstra questioned whether there would be a different methodology applied for determining the capacity valuation for DSM during the 12 peak periods or for Scheduled Generators. Mr Dykstra noted that	

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	currently there is no certainty over DSM's availability during these times. Mr Cremin noted that these issues have been discussed by the REGWG previously. The proposal is likely to result in inconsistent treatment of Scheduled and Non-Scheduled Generators. • Mr MacLean noted that the proposed changes would more correctly allocate Capacity Credits to solar facilities. • Mr Cremin noted that an existing weakness in the rule change assessment process will be re-highlighted in this case as the IMO's assessment of the proposal will not take into account other potential methodologies that could be alternatively implemented. • Mr Everett noted that REGWG had been provided with an opportunity to put forward a recommendation to the MAC but had been unable to do so. Mr Dykstra noted that the commercial views of the REGWG had not made this possible. Mr Dykstra noted that the MAC is required to act in the best interests of the market and not according to the individual commercial interests of its members. Mr Dykstra considered that, irrespective of the resultant capacity valuations, moving away from progressing MMA's proposed approach would be inconsistent with the best interests of the market. • Mr MacLean questioned if a bias should be applied, noting that it is important to supply customers during the majority of the year. Mr Forward noted that generally the whole RCM is geared towards delivering energy for the peak especially when peak demand is the dominant factor in the reliability criterion. • The Chair noted that no matter the reason for the lights going out, there will be a large problem if the market had insufficient capacity to service load. Dr Gould noted that the impact of these situations is compounded during the Hot Season. • Mr Dykstra noted that the IMO's proposal would change the economics of developing an Intermittent Generator considerably. The Chair agreed, noting that the IMO had been conscious of signalling potential changes in the Reserve Capacity allocations to Intermittent Generators in the last three Statement of Opportunities Reports. • Mr Cremin noted that existing Intermittent Generators should not be exposed to regulatory risk due to the "gut feelings" of the system operator. Any decision to progress with a solution needs to account for the impacts on existing Intermittent Generators. The Chair noted that the system operator's opinion is of vital importance with regard to system security. • Mr Forward noted that the IMO is required to review the reliability criteria by the end of 2012. Dr Gould suggested that reviewing the reliability criteria and ensuring that the costs are correctly allocated to Market Customers would be a preferable outcome. • Dr Gould noted that Mr Greg Thorpe's previous comments that Capacity Credits are in effect a pre-payment for energy. The Capacity Credit factor is a representation of the amount of energy that will be available from a wind farm. MMA's concept of Load for Scheduled Generation effectively treats a wind farm as a negative load which	

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	ultimately drives down the need for energy from the Balancer, resulting in lower balancing prices. Mr Kelloway agreed with Dr Gould's synopsis. • Dr Gould considered that a significant regulatory risk would be introduced by the proposed amendments. • The Chair noted that the OoE had advised the IMO that there are a number of wind investors looking at entering the market despite this proposal being considered. • Mr Cremin noted that customers will be the parties that ultimately pay for the amendments. • Mr Craib noted that the proposed changes would impact on the viability of constructing a wind farm in the WEM. Mr Everett noted that Verve Energy was considering building a wind farm and that the proposed amendments have not resulted in an adjustment to their decision. • Mr Forward noted that the decision around the capacity valuation for Intermittent Generators is one of the hardest decisions the market has faced since market start. Mr Forward noted that he was unsure that the market would be in any better position in a year's time to reconsider this issue and so there was no reason to not progress a solution now. Dr Gould agreed, stating that it would be best to progress the IMO's solution through the Rule Change Process, flush out all the issues, appoint an expert to consider these issues further and then the IMO can make a final decision on the proposal. • Mr Cremin noted that the methodology for assigning Capacity Credits to Intermittent Generators needs to make some better allowances for solar as the current Market Rules are not appropriate for this technology. However, Mr Cremin noted that he was concerned that a non-optimal solution was being progressed. Mr Dykstra suggested that maybe the IMO should be considering a solution simply for solar facilities. Mr Forward noted that solar technologies are not the main issue needing attention as there is less penetration of these technologies and less potential penetration in the near future. • The Chair noted that the IMO has an obligation to move forward with proposing a solution to this issue and that the process forward would provide sufficient opportunities for Market Participants to provide their comments. The MAC agreed, although Mr Sutherland questioned how much progressing through the Rule Change Process would cost the market. • Mr Cremin agreed with the IMO that the data available is limited but considered that MMA's proposed methodology would ensure that if the relationship between peak periods and output has been incorrectly identified due to the data restrictions, this will be reflected in the Capacity Credit allocations to these facilities in time. Mr Dykstra noted his concern that progressing with the IMO's proposed solution would set a bad precedent as this would ignore the available evidence and would result in a solution being progressed based purely on the system operator's "gut feel". Mr Dykstra noted that if the IMO is not going to progress with MMA's proposal then Market Participants will need to clearly understand why the IMO's proposed solution is a better approach. Mr Kelloway agreed to provide details of System	

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	Management's modelling to assist the MAC in understanding its position. Mr Kelloway noted that System Management is taking no position on the further development of renewable energy options in the WEM. *Action Point: System Management to provide details of its modelling of the impacts of Intermittent Generation on the WEM and the associated capacity valuation methodology (Work Package 2) to MAC members.* • The Chair questioned whether MAC members would have a different position on the IMO's proposal if there was no existing wind generation on the system. Mr Dykstra considered that there would be nothing to gain from considering this hypothetical view. Mr Huxtable questioned what the impact of allowing for grandfathering would be. The Chair noted that he did not support the introduction of grandfathering provisions. • Mr Campillos questioned if System Management had considered the impacts of improving the reliability criteria. Mr Kelloway noted that it had not to date but that it would do so moving forward. • Mr Dykstra suggested that the IMO progress the Rule Change Proposal and simply note that it was discussed at the MAC. Mr Cremin noted that it is unlikely that different views will be raised and it will be a costly process. The IMO agreed to progress the proposal, noting that it is likely that a number of issues will be raised during the consultation process.	**SM**
7d	**ANCILLARY SERVICES PAYMENT EQUATIONS (WORK PACKAGE 3) [PRC_2010_27]** The Chair introduced Dr Jenny Riesz from ROAM, who had co-authored the report "Assessment of FCS and Technical Rules" for the REGWG's Work Package 3 and was attending the meeting to answer any questions from the MAC regarding the Pre Rule Change Discussion Paper. Mr Forward noted that the REGWG had discussed the ROAM final report for Work Package 3, and had requested that some further analysis be undertaken in relation to the allocation of Load Following and Spinning Reserve costs, prior to the submission of a Rule Change Proposal. The IMO had instructed ROAM to: • consider how the impact of Scheduled Generator deviations from dispatch targets can be reflected in the allocation of Load Following and Spinning Reserve costs; • consider the suggestions made by Verve Energy for the simplification and staged implementation of the proposed changes; and • investigate the use of a proportioning approach for the allocation of Load Following costs and prepare a comparison of this approach and the recommended difference-based approach. ROAM had subsequently prepared the Pre Rule Change Discussion Paper: Ancillary Services Payment Equations (PRC_2010_27) for consideration by the MAC. Mr Forward noted that Verve Energy had raised a concern with the IMO about whether its intentions had been fully reflected in the paper,	

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	and explained that Mr Chin Koay was attending the meeting to discuss the issues on Verve Energy's behalf. Mr Forward proposed to work through the issues and discussion points raised in the IMO's cover paper.	
	Issue 1: Clause 3.14.1 – Inclusion of unintended fluctuations of Scheduled Generators in Load Following costs (attachment 1 to the Rule Change Proposal)	
	Mr Forward noted that Pacific Hydro had suggested to the REGWG that Scheduled Generators might be allocated a proportion of Load Following costs to reflect the impact of their uninstructed fluctuations. There was some discussion about how Load Following costs were currently allocated to Loads and Intermittent Generators and how the cost allocation did not depend on the actual fluctuations of individual Loads or Facilities.	
	In response to a question from Mr Dykstra, Mr Forward advised that the IMO had been unable to obtain statistics on the magnitude of uninstructed fluctuations from Scheduled Generators prior to the meeting. Mr Forward noted that a significant amount of modelling would be required to derive this information, and suggested that the work may not be worth undertaking as the magnitude of the fluctuations is expected to be low, as advised by ROAM. There was some discussion around whether it would in fact be possible to identify and measure unwanted fluctuations. Mr Kelloway noted that some fluctuations (governor response) benefitted the market and should not be discouraged. Mr MacLean suggested that insufficient information was available to make any decision.	
	The Chair suggested that there appeared to be a general agreement not to pursue the matter further. The MAC accepted the IMO's advice that the magnitude of uninstructed Scheduled Generator fluctuations would be costly to determine and probably small. The MAC agreed that the issue should not be pursued any further at this time.	
	Issue 2: Clause 3.13.1, 9.7.1 – Capacity Cost for Spinning Reserve (attachment 2 to the Rule Change Proposal)	
	Mr Forward noted that since the publication of PRC_2010_27 it had been queried whether Market Participants were paying twice for Load Following capacity under the current Market Rules. Mr Koay confirmed that there was no double payment problem at present.	
	Mr Forward asked MAC members whether they considered it appropriate to include a Capacity Cost for Spinning Reserve in the Rule Change Proposal. Mr Dykstra questioned whether the issue had been raised by ROAM. Mr Forward replied that the suggestion had come from Verve Energy. Mr Koay expressed support for the idea, noting that it was consistent with the way in which Load Following was handled. Mr Koay had originally thought that the omission of a Capacity Cost for Spinning Reserve was an oversight, but comments in the old Market Rules indicate that the omission was deliberate. Mr Koay suggested that a Capacity Cost for Spinning Reserve be included for consistency unless a problem is identified.	
	Mr Dykstra questioned whether the change would represent a reallocation or a new cost for Market Participants. Dr Riesz and Mr Forward replied that the change would not involve any new costs but only the more appropriate allocation of existing costs. The Chair and Mr MacLean both considered that the proposed change was reasonable.	

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	Mr Dykstra requested an estimate of the quantum of the impact. The Chair suggested that the IMO could either circulate this information to MAC members or alternatively provide it at the next MAC meeting. Mr Forward suggested that MAC members had no disagreement with the concept but wished to see an estimate of the quantum impact. Mr Sutherland replied that he would want to see the estimate of the quantum impact before expressing support for the concept. Mr Cremin expressed his concerns about the limited options available to generators in this market to pass extra costs through to end users.	
	Action Point: The IMO to provide the MAC with an estimate of the financial impact on Market Participants of amending the Pre Rule Change Discussion Paper: Ancillary Services Payment Equations (PRC_2010_27) to include a Capacity Cost for Spinning Reserve and therefore allocate the capacity payment to Scheduled Generators providing the service	**IMO**
	Issue 3: Clause 3.14.1 – Full load, marginal generation payment for Load Following (attachment 3 to the Rule Change Proposal)	
	Mr Forward advised that ROAM had prepared some additional estimates of Load Following costs and their allocation between Intermittent Generators and loads, under various scenarios and allocation methodologies. A summary was distributed to MAC members and is attached as Appendix 2. Dr Riesz advised that ROAM had revised its estimates and that the values in Table 1 of the handout replaced the values presented in PRC_2010_27. Dr Riesz noted that the estimates assumed that the other proposed amendments to the Market Rules would be implemented.	
	The Chair asked Dr Riesz to explain the difference between the allocation methodology proposed by ROAM and the alternative methodology. Dr Riesz explained that under the "Full Load, Marginal Generation" methodology proposed by ROAM, loads pay the full proportion of their Load Following Requirement, while Intermittent Generators pay the additional increment required for their operation. Under the alternative "Proportional Load and Generation" methodology, the Load Following requirements of loads and Intermittent Generators are assessed separately, and the costs of Load Following are distributed in direct proportion to the individual requirements of each group.	
	Mr Cremin considered that both methodologies constituted a wealth transfer that shifted the costs of Load Following from Loads towards Intermittent Generators. Mr Cremin noted that Intermittent Generators can do little to reduce the variability of their output. The proposed changes would impose a large cost on a small number of generators, who would pass the cost through to a small number of retailers. Mr Cremin questioned whether the issue of causer pays versus socialisation of costs should be considered at a higher level.	
	The Chair replied that the socialisation of Load Following costs might not send appropriate investment signals to future investors in wind. Mr Huxtable questioned whether biomass would become more competitive with wind in response to these signals. There was some discussion about the subsidisation of renewable generation, the approach taken by the National Electricity Market (NEM) and the need for costs to be transparently allocated.	
	Mr Forward asked MAC members which of the two proposed cost allocation	

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	methodologies they preferred. Mr Dykstra expressed a preference for the status quo, estimating that the proposed changes could increase Alinta's operating costs of running its wind farm by one third. Mr Sutherland noted that while ERM Power did not have any Intermittent Generators, he considered that there was a fundamental problem with pushing costs upstream.	
	Mr MacLean queried whether the size of the estimated cost increases was a surprise to Alinta. Mr Dykstra considered that this was the first time that the magnitude of the changes had been obvious. Dr Riesz noted that the increase in Load Following costs to Intermittent Generators was due not only to the proposed allocation methodology changes but also to other changes that would increase the overall cost of Load Following, for example increasing gas prices and changes to how costs are distributed between Load Following and Spinning Reserve. Dr Riesz believed that the NEM applied a causer pays approach on an individual basis to Load Following costs.	
	Mr Dykstra expressed a preference for the Full Load, Marginal Generation methodology, considering that it was not unreasonable to give wind generation some benefit at the margin. The Chair queried whether this methodology had the general support of MAC members. Mr Cremin suggested that a cost increase to Intermittent Generators from $1 million to $17 million represented a large regulatory change. There was some discussion about the extent to which the off-take arrangements of Intermittent Generators would allow them to pass these cost increases through to their customers.	
	Mr Dykstra questioned to what extent the amendments in the Pre Rule Change Discussion Paper could be progressed separately. Dr Riesz responded that some of the proposed changes could be unbundled, including the proposed changes to the Load Following cost allocation methodology.	
	Mr Everett recommended that the Rule Change Proposal proceed, but noted that Verve Energy would be suggesting some further changes to the proposed Amending Rules. Mr Huxtable considered that there was a fundamental difficulty in attempting to apply "market efficiency" to an inefficient product that would not be viable without subsidy. Mr Forward noted that the policy advice received from the Minister to date suggested that a level playing field should apply in respect to renewable generation. Mr Dykstra suggested that this was different to the apparent direction at market start.	
	The Chair asked if there was general support from MAC members for the Full Load, Marginal Generation methodology. Mr Everett noted that Verve Energy did not support this methodology, believing that a true "causer pays" approach should be adopted. The Chair asked Dr Riesz to explain why ROAM had recommended the Full Load, Marginal Generation methodology. Dr Riesz noted that ROAM's recommendation was consistent with a recommendation made by the Econnect to the Office of Energy in 2005. The proposed methodology ensures that the cost allocation to loads for Load Following is unaffected by the extent of Intermittent Generation operating in the SWIS. Under the Proportional Load and Generation methodology, loads would receive a "windfall gain" at the expense of Intermittent Generators, as	

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	this methodology ignores the extent to which the fluctuations of Intermittent Generators cancel out fluctuations in load. The Full Load, Marginal Generation methodology ensures that Intermittent Generators only pay for the additional Load Following costs that they impose on the SWIS. The Chair queried why Verve Energy supported the Proportional Load and Generation methodology. Mr Koay presented an analogy involving a man who has built a house at the top of a hill. The man has been obliged to pay for the construction of a new road, as initially his is the only house and so he is the only user of the road. If another house is then built beside the first, the question is whether the owner of the second house should be obliged to contribute towards the cost of the road. Mr Koay suggested that the Full Load, Marginal Generator methodology was similar to allowing the second house owner to use the road free of charge. Mr Cremin considered that under either methodology new costs were assigned to generators that would eventually need to be passed through to end users. Mr Dykstra noted that marginal costs were not applied to each Intermittent Generator separately, but to Intermittent Generators collectively. The Chair considered that, subject to Verve Energy's concerns, MAC members appeared to be favouring the Full Load, Marginal Generation methodology. Mr Everett offered to circulate some comments explaining Verve Energy's concerns to MAC members for discussion. *Action Point: Verve Energy to circulate its comments on the Pre Rule Change Discussion Paper: Ancillary Services Payment Equations (PRC_2010_27) to MAC members.*	**Verve Energy**
7e	**CURTAILABLE LOADS AND DEMAND SIDE PROGRAMMES [PRC_2010_29]** Mr Forward noted that the aim of the Pre Rule Change Discussion Paper is to address the current operational issues around Curtailable Loads. Mr Forward summarised the background to the paper, noting that the MAC had discussed and reached agreement on a number of key issues relating to Curtailable Loads at its May 2010, June 2010 and August 2010 meetings. Mr Forward advised that the Pre Rule Change Discussion Paper had been developed to reflect the principles agreed by the MAC. Mr Forward sought feedback from MAC members about any issues they had with the implementation of the agreed principles in PRC_2010_29, but noted that he did not want to re-litigate issues on which the MAC had already reached an agreement. Mr Dykstra noted that Alinta had previously sent comments to the IMO about the calculation of Relevant Demand using load data for the previous year. Mr Dykstra gave the example of a load with a Relevant Demand of 100 MW offering 50 MW of capacity. If the peak demand of the load had reduced from 100 MW to 50 MW since the previous summer then the load would be able to meet its capacity requirements without having to reduce its consumption. Mr Dykstra sought Mr Kelloway's thoughts on how System Management can be sure that Demand Side Programmes (DSPs) will deliver their promised capacity. Mr Kelloway responded that System Management's experience of DSPs had been limited, but acknowledged a concern that a requested	

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	reduction might not be delivered. Mr Huxtable considered that DSPs had also provided some good results to the market. Mr Michael Zammit submitted that there was no generally agreed method of measuring Demand Side Management (DSM) response. Mr Zammit considered that it was important to have adequate testing in place and noted that Energy Response always over-contracted for DSM capacity in its DSPs. Mr Huxtable noted that on some occasions Loads can be operating well above their Relevant Demand and so would need to need to reduce their consumption more to meet the requirements. Mr Campillos noted that it was up to the DSM aggregator to ensure that requirements were met, but suggested that Mr Dykstra's example was unlikely. Mr Kelloway considered that he was still not convinced of DSM's ability to deliver reductions at all times of day or on all days of the year. Given the variability of loads, it was likely that the level of response would vary at different times of the year. Mr Kelloway suggested that if a large percentage of Reserve Capacity was provided by DSM then this could result in issues for System Management over the winter months. Mr Forward noted that the IMO was seeking feedback on the two discussion points raised in the cover paper. Mr Forward reiterated that at this stage the IMO was seeking an operational outcome that would allow DSM to operate under the Market Rules, rather than a more general exploration of DSM principles. The Chair asked MAC members whether the paper accurately represented the discussions on Curtailable Load and DSPs at MAC over the past year. MAC members agreed that this was the case, except for Mr Dykstra. Mr MacLean considered that since DSPs created costs for the IMO and System Management they should not be exempt from Market Fees. The Chair noted that at the May 2010 MAC meeting members had agreed not to change the Market Fee arrangements for DSM providers. The Chair proposed that the IMO log the question of Market Fees for DSM providers as an issue to be addressed at a later date. The MAC supported this.	
	Action Point: The IMO to record in its Market Rule Issues Log the concerns of MAC members around the exemption of Demand Side Management aggregators from Market Fees.	**IMO**
	Discussion Point 1: Mr Forward sought the views of MAC members on whether Curtailable Loads (now DSPs) should receive pay as bid Dispatch Instruction Payments (DIPs). Mr Forward proposed not to make any changes to the current arrangements, to prevent any delay to the progress of the Rule Change Proposal. Mr MacLean considered that DSPs should not receive these payments. The MAC agreed that while members had concerns about DIPs for DSPs and would like to consider the issue as part of a broader review, no further action was required in relation to this Rule Change Proposal.	
	Action Item: The IMO to record in its Market Rule Issues Log the concerns of MAC members around the appropriateness of DIPs for DSPs.	**IMO**
	Discussion Point 2: Mr Williams noted that currently when a generator is dispatched upwards for a test it is paid MCAP for the energy produced, but when a Curtailable Load is dispatched for test it receives no equivalent payment. The Chair did not consider this to be a significant issue, but noted	

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	that if this was to change then the matter could considered at a later date. The MAC agreed that DSPs should not be paid when they are dispatched for a test.	
	Mr Campillos raised his concerns about the proposed use of the same 12 Peak Trading Intervals for both the calculation of Individual Reserve Capacity Requirement (IRCR) values and the determination of the Relevant Demand used to measure DSP performance. Mr Campillos queried whether MAC members had fully considered the potential impact of this approach. Mr Campillos suggested that some of the most suitable loads for DSM may become unavailable as a result of the change, since by seeking to reduce their consumption in the 12 Peak Trading Intervals (to reduce their IRCR) they would lower their Relevant Demand levels, making participation is a DSP unattractive.	
	There was some discussion around the extent to which loads were seeking to reduce their IRCRs by adjusting their consumption during expected Peak Trading Intervals, and whether such activities were good or bad for the market. Mr Dykstra considered that the problem was product of the split between the retailer and the DSM provider. Mr Zammit and Mr Campillos disagreed with this opinion.	
	Mr MacLean considered that a customer that could reduce its IRCR would effectively be subsidised by other customers. Mr Campillos considered that the issue was that there needed to be an incentive for loads to reduce at times other than during the 12 Peak Trading Intervals. Mr MacLean suggested that there may be a better way to allocate IRCR apart from the current 12 Peak Trading Interval methodology.	
	The Chair expressed concern that a DSM provider could be selling the same product (Load reduction at Peak) to both consumers and the market.	
	In response to a request from the Chair, Mr Campillos agreed to articulate his concerns in writing for distribution to MAC members.	
	Action Point: DMT Energy to send the IMO a summary of its concerns around the use of the same twelve Peak Trading Intervals for both the calculation of IRCR and the determination of the Relevant Demand level used to measure Demand Side Programme performance.	**DMT Energy**
	Action Point: The IMO to distribute the summary provided by DMT Energy of its concerns regarding the calculation of Relevant Demand for a Demand Side Programme to MAC members.	**IMO**
	The MAC supported the progression of PRC_2010_29 into the rule change process.	
	Action Point: The IMO to formally submit PRC_2010_29: Curtailable Loads and Demand Side Programmes into the rule change process.	**IMO**
7f	**LIMITS TO EARLY ENTRY CAPACITY [PRC_2010_30]**	
	The Chair noted that MAC members had discussed the Pre Rule Change Discussion Paper at the October 2010 meeting. As a result of the MAC discussion the IMO engaged Marchment Hill Consulting (MHC) to undertake an assessment of PRC_2010_30 against the Wholesale Market Objectives. A summary of the advice provided by MHC was distributed to MAC members prior to the meeting.	

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	In summary, MHC found the most significant impact of the proposal was negative in terms of a Wholesale Market Objective (c). MHC found a minor positive impact (on balance) to Wholesale Market Objective (a) and a minor positive impact to Wholesale Market Objective (d).	
	Mrs Papps clarified that MHC had identified both positive and negative impacts to Wholesale Market Objective (a). Mr MacLean questioned whether the full report provided any further explanation of MHC's comment that the proposal "socialises commissioning risks". Mrs Papps advised that the IMO had now confirmed that the MHC report was not confidential and so could be distributed to MAC members. A copy of the full report had already been provided to Mr Dykstra.	
	Action Point: The IMO to distribute the advice provided by Marchment Hill Consulting on the Pre Rule Change Discussion Paper: Limits to early entry capacity payments (PRC_2010_30) to MAC members.	**IMO**
	Mr Dykstra noted that the report discussed commissioning but considered that much of the discussion applied only to generators. Mr Dykstra also questioned how Wholesale Market Objective (c) should be interpreted in this context, and suggested that further discussion should be held off until the December 2010 MAC meeting when members would have had the opportunity to review the full report. It was agreed that there would be value in the IMO meeting with Mr Dykstra prior to this meeting to discuss the MHC report in more detail.	
	Action Point: The IMO to meet with Alinta to discuss the advice provided by Marchment Hill Consulting on the Pre Rule Change Discussion Paper: Limits to early entry capacity payments (PRC_2010_30).	**IMO**
	Action Point: The IMO to present the Pre Rule Change Discussion Paper: Limits to early entry capacity payments (PRC_2010_30) again to the MAC at the December 2010 meeting for further discussion.	**IMO**
7g	**ACCEPTABLE CREDIT CRITERIA [RC_2010_36]**	
	Mr Williams noted that the IMO had received a great deal of feedback around issues relating to Acceptable Credit Criteria (ACC) requirements. The IMO has engaged an external consultant to undertake a review of these issues. The IMO expects that the results of this review will be available to the IMO by the end of November 2010.	
	Mrs Papps noted that Synergy had formally submitted its Rule Change Proposal into the rule change process. The scope of this Rule Change Proposal overlapped the scope of the IMO's review into ACC issues.	
	In response to a question from the Chair, Mr MacLean noted that RC_2010_36 sought to remove the requirement in the Market Rules for a participant to provide a solicitor signed ACC Form in relation to a Credit Support Provider on the IMO's List of Acceptable Credit Providers.	
	Mr MacLean questioned why the Queensland Treasury Corporation was on the IMO List but not the Western Australian Treasury. Mr Huxtable responded that the Western Australian Treasury was not permitted to provide this type of support and that the Queensland Treasury Corporation was probably a provider of Credit Support for a current Market Participant.	
	The Chair proposed that the IMO process the Rule Change Proposal but	

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	delay its progress until the results of the IMO review can be considered. In response to a query from Mr Huxtable, Mrs Papps clarified that the IMO would publish the relevant outcomes of its review in an addendum to the Rule Change Notice, so that participants could consider this information when preparing their first period submissions. The MAC supported this proposal. *Action Point: The IMO to extend the first submission period for the Rule Change Proposal: Acceptable Credit Criteria (RC_2010_36) as necessary to allow the IMO to complete its review of the issues raised by Market Participants around the Acceptable Credit Criteria requirements and present its findings in an addendum to the Rule Change Notice for further consideration by Rule Participants when preparing their submissions.*	**IMO**
8a	**MARKET PROCEDURE CHANGE OVERVIEW** The MAC noted the overview of recent and upcoming procedure changes.	
9	**MAC MEMBERSHIP REVIEW: 2011 PROCESS** The Chair noted that the IMO had provided members with additional information about the process and guidelines it used in its annual review of the composition of the MAC. Mrs Papps confirmed that there were an additional two positions available on the MAC, for a Market Customer and a Market Generator, as result of the Rule Change Proposal: MAC Membership Review (RC_2010_15). There was some discussion about the IMO's endeavours during the selection process to ensure an equal representation of Market Customers and Market Generators on the MAC. The MAC noted the IMO's update on the process for the 2011 review of MAC membership. Mr MacLean noted that it was a comprehensive process.	
10	**GENERAL BUSINESS** There was no general business raised.	
11	**NEXT MEETING** Meeting No. 34 to be confirmed, following a request from Mr Dykstra.	
CLOSED: The Chair declared the meeting closed at 5.15pm.		

Agenda item 4: 2010 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.

#	Action	Responsibility	Meeting arising	Status/Progress
62	The IMO to send a letter to the Office of Energy and the ERA on behalf of the MAC requesting the introduction of licensing obligations for DSM Providers.	IMO	May	Complete.
78	System Management to further develop the details of option 3 for the future procurement of Spinning Reserve and Load Following and then provide an update to the MAC.	SM	June	Complete. Paper on today's meeting agenda.
88	The Office of Energy to provide the IMO with a copy of its report on gas contingency service options for distribution to MAC members.	OoE	August	The IMO has requested this (2 September 2010 and 2 December 2010) and will circulate it once received.

#	Action	Responsibility	Meeting arising	Status/Progress
89	The IMO to distribute the report provided by the Office of Energy on gas contingency service options (action point 88) to MAC members.	IMO	August	See above.
111	The IMO to formally submit its updated Reserve Capacity Security Rule Change Proposal RC_2010_12.	IMO	September	Completed. First submissions close 20 January 2011.
119	The IMO, in March 2011, to review with System Management whether there is an issue with the registration and dispatch of a large number of small Demand Side Programmes, and report back to the MAC.	IMO	September	
121	The IMO to present to the MAC a worked example comparing the payments associated with the dispatch of a peaker against those associated with the dispatch of a Demand Side Programme.	IMO	September	
124	The MAC to reconfirm its advice to the IMO to extend RC_2010_24 at the November MAC meeting.	IMO	October	Completed. Discussed at November MAC meeting.
126	The OoE and Western Power to provide bi-monthly updates to the MAC on status of any regulatory changes relating to NCS procurement.	OoE and WP	October	To discuss at December meeting.
127	The MAC Chair to write to Western Power to request it to include a requirement for appropriate metering for settlement in any NCS contracts.	MAC Chair	October	Completed.
128	The IMO and System Management to discuss whether any additional amendments to the Market Rules are required to ensure that NCS is included in the Dispatch Merit Order.	IMO and SM	October	System Management and the IMO have met and agree that the current rules are silent on the priority of NCS dispatch and that further amendments are required to give priority to the dispatch of NCS over other dispatch. This will be contained in the Draft Rule Change Report for RC_2010_11: Removal of NCS EOI and Tender.
130	The IMO to consider whether further information on new large loads should be included in the Statement of Opportunities.	IMO	October	

#	Action	Responsibility	Meeting arising	Status/Progress
131	The IMO to progress the Rule Change Proposal: Certification of Reserve Capacity (RC_2010_14) into the formal rule change process, subject to the agreed amendments to the drafting.	IMO	October	Completed.
134	The IMO to update the drafting of RC_2010_23 to clarify that an authorised officer of the company would be required to affirm that a Consequential Outage had occurred and provide relevant details to the best of its knowledge of the events which resulted in the Consequential Outage.	IMO	October	Completed. Draft Rule Change Report published 18 November 2010.
135	The IMO to progress the simplistic solution to the Rule Change Proposal: Consequential Outage- Relief from Capacity Refunds and Unauthorised Deviation Penalties (RC_2010_23), subject to an annual review of Consequential Outages by System Management being included in the Amending Rules and details of the information requirements being provided in a Market Procedure.	IMO	October	Completed. Draft Rule Change Report published 18 November 2010.
136	The IMO to consider incorporating: • an ability to draw down of Reserve Capacity Security prior to the end of the Capacity Year and diverting this to a SRC fund; and • potential adjustments to the capacity price as a result of reducing a Market Participants Capacity Credits to zero, and update the Pre Rule Change Discussion Paper: Capacity Credit Reduction (PRC_2010_28) accordingly.	IMO	October	
137	The IMO to present an updated version of the Pre Rule Change Discussion Paper: Capacity Credit Reduction (PRC_2010_28) to the MAC for further discussion at the December 2010 MAC meeting.	IMO	October	
141	The IMO to prepare a Pre Rule Change Discussion Paper to propose that Capacity Cost Refunds are held in a consolidated fund to pay for SRC.	IMO	October	On the IMO issues and Rule Change log for prioritisation.
142	The IMO to amend the minutes of Meeting No. 32 to reflect the points raised by the MAC and publish on the website as final	IMO	November	Completed.

#	Action	Responsibility	Meeting arising	Status/Progress
143	The IMO to canvass the views of MAC members on moving the date for the next MAC meeting to 15 December 2010.	IMO	November	Completed.
145	The IMO to request LECG to update the Confidentiality Status Classes in the WEM report to reflect System Management's position as a governance participant in the WEM.	IMO	November	Underway.
146	The IMO to prepare a Pre Rule Change Discussion Paper to implement the proposed changes to the confidentiality status classes which contains the full Amending Rules and present back to the MAC for further discussion.	IMO	November	Underway.
147	The IMO to update the terms of reference for the System Management Procedure Change and Development Working Group to reflect the agreed change in membership.	IMO	November	Completed.
148	Members to provide the IMO with any specific comments on the REGWG Final Report by 8 December 2010.	IMO	November	Completed.
149	The IMO to update the REGWG Final Report to: • reflect comments received from MAC members; • remove references to Pre Rule Change Discussion Papers being developed by the IMO; • include an explanation of any acronyms used in the report; and • note that the report had been prepared by the IMO.	IMO	November	Underway.
150	The IMO to present its recent Board presentation on the RCM at the December MAC meeting.	IMO	November	Completed. Presentation on today's agenda.
151	The IMO to update the Rule Change Proposal: Partial Commissioning for	IMO	November	Completed. First submissions close 20 January 2011.

#	Action	Responsibility	Meeting arising	Status/Progress
	Intermittent Generators (RC_2010_22) to: • clarify that the Max_2 variable is based on the "…second highest level of output achieved during a Trading Interval during the Trading Month…" • include brackets around the "$2 \times Max_2$" in the formula; and • reflect the ability for a Market Participant to provide the IMO with an expert report attesting that the Facility has been built in accordance with its certification specifications.			
152	The IMO to progress RC_2010_22 through the Rule Change Process, subject to the incorporation of the agreed amendments.	IMO	November	Completed. First submissions close 20 January 2011.
153	System Management to provide details of its modelling of the impacts of Intermittent Generation on the WEM and the associated capacity valuation methodology (Work Package 2) to MAC members.	IMO	November	Complete.
154	The IMO to provide the MAC with an estimate of the financial impact on Market Participants of amending the Pre Rule Change Discussion Paper: Ancillary Services Payment Equations (PRC_2010_27) to include a Capacity Cost for Spinning Reserve and therefore allocate the capacity payment to Scheduled Generators providing the service.	IMO	November	Underway. ROAM is currently calculating this, a verbal update will be provided at the MAC meeting.
155	Verve Energy to circulate its comments on the Pre Rule Change Discussion Paper: Ancillary Services Payment Equations (PRC_2010_27) to MAC members.	Verve Energy	November	Completed.
156	The IMO to record in its Market Rule Issues Log the concerns of MAC members around the exemption of Demand Side Management aggregators from Market Fees.	IMO	November	Completed.
157	The IMO to record in its Market Rule Issues Log the concerns of MAC	IMO	November	Completed.

#	Action	Responsibility	Meeting arising	Status/Progress
	members around the appropriateness of Dispatch Instruction Payments for Demand Side Programmes.			
158	DMT Energy to send the IMO a summary of its concerns around the use of the same twelve Peak Trading Intervals for both the calculation of IRCR and the determination of the Relevant Demand level used to measure Demand Side Programme performance.	DMT Energy	November	Completed.
159	The IMO to distribute the summary provided by DMT Energy of its concerns regarding the calculation of Relevant Demand for a Demand Side Programme (action point 158) to MAC members.	IMO	November	Completed.
160	The IMO to formally submit PRC_2010_29: Curtailable Loads and Demand Side Programmes into the rule change process.	IMO	November	Completed.
161	The IMO to distribute the advice provided by Marchment Hill Consulting on the Pre Rule Change Discussion Paper: Limits to early entry capacity payments (PRC_2010_30) to MAC members.	IMO	November	Completed, included in today's meeting papers.
162	The IMO to meet with Alinta to discuss the advice provided by Marchment Hill Consulting on the Pre Rule Change Discussion Paper: Limits to early entry capacity payments (PRC_2010_30).	IMO	November	Completed.
163	The IMO to present the Pre Rule Change Discussion Paper: Limits to early entry capacity payments (PRC_2010_30) again to the MAC at the December 2010 meeting for further discussion.	IMO	November	Completed. On today's agenda.
164	The IMO to extend the first submission period for the Rule Change Proposal: Acceptable Credit Criteria (RC_2010_36) as necessary to allow the IMO to complete its review of the issues raised by Market Participants around the Acceptable Credit Criteria requirements and present its findings in an addendum to the Rule Change Notice for further consideration by	IMO	November	

#	Action	Responsibility	Meeting arising	Status/Progress
	Rule Participants when preparing their submissions.			

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)	8 December 2010
Fast track with Consultation Period open	2
Standard Rule Changes with 1st Submission Period Open	7
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)	5
Standard Rule Changes with 2nd Submission Period Open	2
Standard Rule Changes with 2nd Submission Period Closed (final report being prepared)	0
Rule Changes - Awaiting Minister's Approval and/or Commencement	3
Total Rule Changes Currently in Progress	19

Potential changes logged by the IMO- Not yet formally submitted	October	November
High Priority (to be formally submitted in the next 3/6 months)	0	0
Medium Priority (may be submitted in the next 6/12 months)	25	26 (+4/-3)
Low Priority (may be submitted in the next 12/18 months)	24	26 (+2/-0)
Potential Rule Changes (H, M and L)	49	52
Minor and typographical (submitted in three batches per year)	15	25
Total Potential Rule Changes	64	77

The changes in the rule change and issues log (from October to November) has arisen from:

Priority	Issue	Status
High	N/a	N/a
Medium	In: • Intermittent Generator Data: REGWG requested that aggregated intermittent generator data be made publically available	• On the Rule Change and Issue Log.
	• The Market Rules and the Loss Factor Market Procedure are currently inconsistent in their treatment of deriving loss factors for Non-Dispatchable loads under 1000kVa peak consumption.	• On the Rule Change and Issue Log.
	• Dispatch Instruction Payments (DIPs) for Demand Side Programmes (DSPs): The MAC raised concerns about the appropriateness of DIPs for DSPs. Some MAC members consider that DSPs should not receive a further payment when dispatched as they produce no additional energy and incur no additional cost that would require an energy payment that is not already covered by a capacity payment (from November 2010 MAC meeting).	• On the Rule Change and Issue Log.
	• Declared Market Projects: The IMO must seek budget approval from the Minister and ERA for Allowable Revenue over a 3 year period. The Market Evolution Project did not meet the 15% threshold because the project started too late in the Allowable Revenue period.	• On the Rule Change and Issue Log.
	Out: • Supplementary Reserve Capacity (SRC) funding.	• There were two issues on the Rule Change and Issue log regarding SRC funding. This has been rationalised to one issue. The IMO will look to progress the consolidated fund for SRC early in 2011.
	• Provision of Commissioning Information by System Management: The updates to Commissioning provisions rule change (RC_2009_08) included a provision for System Management to provide the IMO with upcoming commissioning test information for publication. This Rule Change Proposal corrects the timing provisions.	• Progressed as Fast Track RC_2010_34
	• System Restart Costs: The ERA has set the	• Progressed as PRC_2010_33,

Priority	Issue	Status
	System Restart total cost as zero for 2011/12 and 2012/13 in its recent Allowable Revenue review. Under the current settlement rules Verve Energy will be charged the total payment paid to other suppliers for System Restart service in addition to providing any further service required by System Management under clause 3.11.7A with no compensation.	on today's MAC meeting agenda.
Low	In: • Assessment of whether rule changes are needed to support NCS instructions to Non-Scheduled Generators to decrease output (from October 2010 MAC meeting). • Demand Side Management and Market Fees: The MAC raised concerns around the exemption of demand side management aggregators from market fees (from November 2010 MAC meeting).	• On the Rule Change and Issues Log. • On the Rule Change and Issues Log.

APPENDIX 1: FORMALLY SUBMITTED RULE CHANGES

Fast Track Rule Change with Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2010_34	22/11/2010	Provision of Commissioning Information by System Management	IMO	Submission period ends	13/12/2010
RC_2010_35	17/11/2010	Use of Forecasts in SRC Assessment	IMO	Submission period ends	09/12/2010

Standard Rule Change with First Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2010_12	17/11/2010	Required Level and Reserve Capacity Security	IMO	Submission period ends	20/01/2011
RC_2010_14	06/12/2010	Certification of Reserve Capacity	IMO	Submission period ends	25/01/2011
RC_2010_22	18/11/2010	Partial Commissioning of Intermittent Generators	IMO	Submission period ends	20/01/2011
RC_2010_25	29/11/2010	Calculation of capacity value for Intermittent Generators – Methodology 1 (IMO)	IMO	Submission period ends	04/02/2011
RC_2010_29	02/02/2010	Curtailable Loads and Demand Side Programmes	IMO	Submission period ends	01/02/2011
RC_2010_36	29/10/2010	Acceptable Credit Criteria	Synergy	Submission period ends	20/12/2010
RC_2010_37	30/11/2010	Calculation of capacity value for Intermittent Generators – Methodology 2 (Griffin Energy)	Griffin Energy	Submission period ends	04/02/2011

Standard Rule Change with First Submission Period Closed

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2010_08	15/04/2010	Removal of DDAP uplift when less than facility minimum generation	Griffin Energy	Publish Draft Rule Change Report	17/12/2010
RC_2010_11	15/10/2010	Removal of Network Control Services Expression of Interest and Tender Process from the Market Rules	IMO	Publish Draft Rule Change Report	29/11/2010
RC_2010_19	25/10/2010	Settlement Cycle Timeline	IMO	Publish Draft Rule Change Report	24/01/2011
RC_2010_20	08/10/2010	Market Fees	IMO	Publish Draft Rule Change Report	17/12/2010
RC_2010_21	15/10/2010	Providing Price Related Standing Data to System Management	IMO	Publish Draft Rule Change Report	24/12/2010

Standard Rule Change with Second Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2010_23	03/08/2010	Consequential Outage – Relief from capacity refund and unauthorised deviation penalties	Alinta	Submission period ends	11/11/2010
RC_2010_24	03/08/2010	Adjustment of Relevant Level for Intermittent Generation Capacity	Alinta	Submission period ends	20/01/2011

Standard Rule Change with Final Report Published

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2009_08	21/04/2009	Updates to Commissioning Provisions	IMO	Commencement	01/01/2011
RC_2009_37	14/05/2010	Equipment Tests	System Management	Commencement	01/02/2011
RC_2010_06	27/04/2010	Application of Spinning Reserve to Aggregated Facilities	Griffin Energy	Commencement	01/04/2011

Agenda Item 5b: Limits to early entry capacity payments (PRC_2010_30)

1. BACKGROUND

Currently the timeframe for new capacity to enter the Reserve Capacity Mechanism is a four-month window centralised around the start of a new Capacity Year on 1 October (the window for entry is between 1 August and 30 November). This timeframe allows new Facilities to enter the market and receive the benefit of Capacity Credits and any associated income stream from 1 August of Year 3 of the Reserve Capacity Cycle. The current window of entry applies for Reserve Capacity Cycles up to and including 2009.

In 2009, the IMO proposed to retain the four month window of entry but brought the window forward to start on 1 June, with all capacity to be fully available no later than 1 October each year[1]. This new timeframe allows new Facilities to enter the market and receive the benefit of Capacity Credits and any associated income stream from 1 June of Year 3 of the Reserve Capacity Cycle. This changed window of entry applies for Reserve Capacity Cycles from 2010 onwards.

Alinta has submitted a Pre-Rule Change Discussion Paper (attached as appendix 1) which seeks to preclude any newly accredited Facility's that are not Scheduled or Non-Scheduled Generators from being able to receive Capacity Credit payments prior to the close of the Reserve Capacity window in the year that the Reserve Capacity Obligation first applies.

The MAC discussed the Pre-Rule Change Discussion Paper at its 13 October 2010 meeting. The following issues were discussed:

- Alignment of the proposal with the 1 October Reserve Capacity Year or the close of the window of entry. The MAC agreed that it was more appropriate that the proposal align with the 1 October Reserve Capacity Year;
- The commissioning activities undertaken by DSM aggregators i.e. installation of pulse meters;
- The potential regulatory risk associated with implementation of the Rule Change Proposal for the 2009 and 2010 Reserve Capacity Cycles given that DSM aggregators have already contracted on the current Market Rules currently in effect; and
- The assessment of the proposal against the Wholesale Market Objectives.

As a result of the MAC discussion, the IMO engaged Marchment Hill Consulting to undertake as assessment of the Rule Change Proposal against the Wholesale Market Objectives. This assessment is attached as appendix 2 to this paper.

3. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Discuss** the assessment against the Wholesale Market Objectives.

[1] www.imowa.com.au/RC_2009_11

Agenda item 5b, appendix 1:

Wholesale Electricity Market
Pre Rule Change Proposal Form

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

Change requested by:

Name:	Corey Dykstra
Phone:	9486 3749
Fax:	9221 9128
Email:	corey.dykstra@alinta.net.au
Organisation:	Alinta Sales Pty Ltd
Address:	Level 9, 12-14 The Esplanade, PERTH WA 6000
Date submitted:	<date submitted to the IMO>
Urgency:	1 - High
Change Proposal title:	Limits to early entry capacity payments
Market Rule(s) affected:	4.1.26

Introduction

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

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

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

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

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

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

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

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

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

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

Details of the proposed Market Rule Change

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

Rule Change Proposal

The Rule Change Proposal is for any **newly** accredited Facility that is not a Scheduled or a Non-Scheduled Generator to be precluded from being able to receive capacity payments prior to the close of the reserve capacity window in the year that the Reserve Capacity Obligation first applies (i.e. 1 December 2011 and thereafter 1 October).

The effect of the proposed rule change would be to preclude **newly** accredited Curtailable Loads, Dispatchable Loads and Interruptible Loads from being able to receive capacity payments prior to 1 December 2011 or thereafter 1 October in the year that the Reserve Capacity Obligation first applies.

Background

Capacity from newly accredited Facilities may currently be made available to the market at any time during a four-month window (currently between 1 August and 30 November) centralised around 1 October. Market Participants are able to nominate any date within the window, and may revise their expected entry date as the project nears completion.

It is understood that the objective of allowing 'new' Facilities to enter the market and receive Capacity Credit payments from as early as 1 August was to encourage 'new' Scheduled or Non-Scheduled Generators to enter the market as early as possible, so that should there be any subsequent delays in commissioning and/or unplanned outages (i.e. Forced Outages) then these events would be less likely to affect the security and reliability of the power system over the summer period when demand reaches system peaks.

From 2012 onwards, the four-month window will shift, so that capacity payments may be received as early as 1 June in the year that the Reserve Capacity Obligation first applies.

The early entry of new capacity imposes a financial cost on the market as the capacity price is not adjusted to account for the additional capacity made available to the market. However, it appears that this additional cost has been judged as being appropriate in order to support the effective commissioning of new scheduled or non-scheduled generation, which then reduces the risk to power system security and reliability over the summer period when demand reaches system peaks.

Reason for the Rule Change Proposal

An outcome of the early entry provisions of the Market Rules is that capacity provided by any newly accredited Facility is able to receive capacity payments as early as 1 August (or 1 June from 2012) in the year that the Reserve Capacity Obligation first applies. Such newly accredited 'Facilities' include capacity from Curtailable Loads, Dispatchable Loads and Interruptible Loads.

- For capacity year 2011/12, which commences on 1 October 2011, if all of the estimated capacity provided by newly accredited Curtailable Loads sought to receive capacity payments from 1 August 2011, the estimated additional cost to the market would be around $2.5 million.
- For capacity year 2012/13, which commences on 1 October 2012, it is estimated that more than 400 MW of Curtailable Load has been accredited, which represents an increase of around 200 MW on the amount accredited for the 2011/12 capacity year. If all of the estimated capacity provided by these newly accredited Curtailable Loads sought to receive capacity payments from 1 June 2012, the estimated additional cost to the market would be around $8.5 million.

Alinta considers that the risk to power system security and reliability associated with capacity provided by newly accredited Facilities that are not Scheduled or Non-Scheduled Generators differs materially to that of newly accredited Scheduled or Non-Scheduled Generators.

This is principally because capacity provided by newly accredited Facilities that are not Scheduled or Non-Scheduled Generators (i.e. Curtailable Loads, Dispatchable Loads and Interruptible Loads) are typically existing loads, and so would not be expected to require an extended period to ensure they are 'commissioned'. Even if newly accredited Curtailable Loads, Dispatchable Loads and Interruptible Loads were not existing loads, it appears unlikely that capacity provided by such loads would represent a risk to the security and reliability of the power system over the summer period when demand reaches system peaks.

Consequently, Alinta considers that the additional cost to the market of **newly** accredited Facilities that are not Scheduled or Non-Scheduled Generators receiving capacity payments prior to 1 October in the year that the Reserve Capacity Obligation first applies cannot be justified based on the reduction in risk to power system security and reliability over the summer period when demand reaches system peaks.

2. Explain the reason for the degree of urgency:

It appears that for the 2009/10 capacity year, a significant proportion of the capacity from newly accredited Facilities that were not Scheduled or Non-Scheduled Generators sought to receive capacity payments from the earliest possible date, being 1 August 2010.

It appears reasonable to assume that for future capacity years, capacity from newly accredited Facilities that were not Scheduled or Non-Scheduled Generators will similarly seek to receive capacity payments from the earliest possible date, being 1 August 2011 and then from 1 June each year.

Given the unprecedented increase in capacity being made available to the market from newly accredited Facilities that are not Scheduled or Non-Scheduled Generators, the resulting cost to the market will be significant.

As noted above, it is considered that the additional cost imposed on the market due to **newly** accredited Facilities that are not Scheduled or Non-Scheduled Generators receiving capacity payments prior to 1 October in the year that the Reserve Capacity Obligation first applies cannot be justified based on the reduction in risk to power system security and reliability over the summer period when demand reaches system peaks.

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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 <u>underline</u> words added)

4.1.26. Reserve Capacity Obligations apply:

(a) in the case of the first Reserve Capacity Cycle:

i. from the Initial Time, for Facilities that were commissioned before Energy Market Commencement;

ii. from the Trading Day commencing on the scheduled date of commissioning, as specified in accordance with clause 4.10.1(c)(iii)(7), for Scheduled Generators and Non-Scheduled Generators commissioned between Energy Market Commencement and 30 November 2007, inclusive; and

iii. from the Trading Day commencing on 1 October 2007 for Interruptible Loads, Curtailable Loads or Dispatchable Loads commissioned after Energy Market Commencement; and

(b) for subsequent Reserve Capacity Cycles up to and including 2009:

i. from the Trading Day commencing on 1 October of Year 3, for Facilities that were commissioned as at the scheduled time of the Reserve Capacity Auction for the Reserve Capacity Cycle as specified in clause 4.1.18(a) or for Facilities which have provided Capacity Credits in one or both of the two previous Reserve Capacity Cycles; and

ii. from the Trading Day commencing on the scheduled date of commissioning, as specified in accordance with clause 4.10.1(c)(iii)(7), or as revised in accordance with clause 4.27.11A or clause 4.27.11D, for Scheduled and Non-Scheduled Generation Facilities commissioned between 1 August of Year 3 and 30 November of Year 3~~.~~; and

iii. from the Trading Day commencing on 1 December of Year 3, for Interruptible Loads, Curtailable Loads or Dispatchable Loads; and

(c) for subsequent Reserve Capacity Cycles from 2010 onwards:

i. from the Trading Day commencing on 1 October of Year 3, for Facilities that were commissioned as at the scheduled time of the Reserve Capacity Auction for the Reserve Capacity Cycle as specified in clause 4.1.18(a) or for Facilities which have provided Capacity Credits in one or both of the two previous Reserve Capacity Cycles; and

ii. from the Trading Day commencing on the scheduled date of commissioning, as specified in accordance with clause 4.10.1(c)(iii)(7), or as revised in accordance with clause 4.27.11A or clause 4.27.11D, for Scheduled and Non-Scheduled Generation Facilities commissioned between 1 June of Year 3 and 1 October of Year 3~~.~~; and

iii. from the Trading Day commencing on 1 October of Year 3, for Interruptible Loads, Curtailable Loads or Dispatchable Loads.

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

Market Rule 2.4.2 states that the IMO must not make Amending Rules unless it is satisfied that the Market Rules, as proposed to be amended or replaced, are consistent with 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.

Alinta considers that the Rule Change Proposal as proposed to be amended or replaced, are consistent with, and better achieve, the Wholesale Market Objectives. Specifically, Alinta considers that the Rule Change Proposal would:

- better achieve Market Objective (a) as it would reduce the cost to the market by not paying for new capacity where such payment does not provide commensurate market benefits;
- better achieve Market Objective (b) as it removes an incentive for the inefficient early entry of capacity from Facilities that are not Scheduled or Non-Scheduled Generators;
- better achieve Market Objective (c) by avoiding discrimination in that market against particular energy options and technologies, as the need to commission Scheduled and Non-Scheduled Generators makes it practically impossible for capacity from these Facilities to be made available to the market at the start of the reserve capacity window (i.e. 1 August 2011 or 1 June thereafter);
- better achieve Market Objective (d) by minimising the long-term cost of electricity supplied to customers from the South West interconnected system; and
- is not inconsistent with Market Objective (e).

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

Alinta has not been able to identify that there would be any costs associated with the Rule Change Proposal.

As outlined above, if all of the estimated capacity provided by newly accredited Curtailable Loads sought to receive capacity payments in 2011 and 2012, the estimated additional cost to the market would be around $11 million.

It appears reasonable to assume that for future capacity years, capacity from newly accredited Facilities that were not Scheduled or Non-Scheduled Generators will similarly seek to receive capacity payments from the earliest possible date, being 1 June each year.

Given the unprecedented increase in capacity being made available to the market from newly accredited Facilities that are not Scheduled or Non-Scheduled Generators, the resulting cost to the market will be significant.

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Tuesday, 2 November 2010

REPORT: RULE CHANGE PROPOSAL FOR LIMITS TO EARLY ENTRY CAPACITY PAYMENTS

Below is our assessment of the above Rule Change Proposal in relation to the Market Objectives.

Background

1. The IMO has in the last 18 months considered a number of concepts and rule change proposals intended to:
   - manage the risk that new capacity for which the market has paid is available in time for the peak demand period of the year.
   - make the provision of new capacity to the market a more attractive proposition for potential investors.
2. Two relevant rule changes have been passed:
   - RC_2009_10, which introduces the concept of Early Certified Reserve Capacity (ECRC). ECRC carries a guarantee that Capacity Credits will be awarded to the holder, thereby providing certainty to investors that a project that has obtained ECRC will in due course produce an income.
   - RC_2009_11, which alters the timing of the window in which new capacity can enter the market, including changing the earliest date from which a new project can receive Capacity Credits. The rationale for this rule change was to increase the incentive for new capacity providers to complete their projects early, thereby reducing the risk to the market that commissioning delays would render that capacity unavailable during the peak demand period of the year.

Current rule change proposal

3. Alinta Sales Pty Ltd. has put forward a further Rule Change Proposal that argues for excluding demand-side capacity providers (providers who are neither Scheduled nor Non-Scheduled Generators) from receiving capacity payments prior to the close of the reserve capacity window.
4. Alinta's argument for excluding demand-side options (referred to for convenience hereafter as DSM) suggests that:
   - Providing early payments to DSM provides less benefit to the market (in terms of incenting providers to complete their projects early) than doing so for non-DSM capacity providers, because the time taken and risks involved in commissioning DSM are less than for non-DSM providers.

- The cost to the market of providing early payments to DSM providers will be significant given the quantity of DSM expected to become available in the next few years.
- In summary, we would infer that Alinta are arguing that the current rules will provide for the inefficient over-provision of DSM, imposing costs on the market without delivering commensurate benefits.

5. Alinta also suggest that the proposed rule change will avoid discriminating against non-DSM providers, whose commissioning requirements "make it practically impossible for capacity from these Facilities to be made available to the market at the start of the Reserve Capacity Window".

Commissioning risks from capacity providers' perspective

6. MHC's view is that commissioning risks would generally be expected to lie with the constructor (who is best equipped to manage them) – in any case, not with the buyer of services from the facilities being constructed (in this case, the market).
7. From a capacity provider's perspective, the risks in relation to commissioning would mainly be:
    - 'Late' completion of commissioning (past the close of the Reserve Capacity Window), incurring an obligation to refund capacity payments
    - 'Early' completion of commissioning (prior to the opening of the Reserve Capacity Window) implying that construction and commissioning costs have been incurred earlier than necessary for no incremental revenue.
8. Capacity providers' preferences for the Reserve Capacity Window would therefore be expected to be:
    - As broad as possible, to increase their certainty of hitting the window
    - As early as possible, to limit their exposure to refund payments by reducing the multiplier.

Commissioning risks from the market's perspective

9. It would appear that the risk to the market of late commissioning could be much higher than the penalty borne by the late-commissioning provider, if the non-availability of capacity had the potential to threaten system security. The market is effectively left with a residual risk.
10. Therefore it appears that, qualitatively speaking, the rationale for providing additional incentives for early completion of commissioning (by bringing forward the closing of the Reserve Capacity Window) is sound since although the market will pay for reserve capacity from an earlier date (all else being equal) there is a benefit gained in the reduction in the risk to system security.
11. The 'early payment' mechanism will, in effect, pay for early commissioning at the capacity price, paid for the amount of time the facility is available prior to when it is 'really' needed. The value of early commissioning to the market is not, however, obviously related to the capacity price and the marginal value of early commissioning to the market, in terms of risk reduction, probably diminishes the more capacity is commissioned early.
12. Consequently, while limiting the amount of capacity (via the proposed Rules Change) that was incented to commission early would probably improve the efficiency of the market it is difficult to determine (based on qualitative arguments only) how large the reduction should be to maximise efficiency.

Relevant Market Objectives

13. MHC's view is that the Market Objectives of primary importance in relation to the rule change proposal are:

- Objective (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 proposed Rule Change would enhance long-run efficiency if it corrected a tendency for the market to provide too much DSM or to pay too much for it.
- Objective (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 Rule Change contemplates different treatment for capacity providers based on the technology by which they make capacity available. So as not to offend Objective (c) it would therefore need to be established that the technology options (i.e. DSM vs non-DSM) were not exact substitutes in economic terms.

14. MHC considers that other Market Objectives are of minor, if any, relevance to proposal:

- Objective (b): *to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors.* As written, this Objective offers no guidance on competition between generators and demand-side capacity providers.
- Objective (d): *to minimise the long-term cost of electricity supplied to customers from the South West interconnected system*. MHC considers this Objective to be of secondary importance because the order of costs at stake in consideration of the Rule Change Proposal are relatively small in the context of the total capital costs of the assets concerned. Nevertheless, it is acknowledged that early capacity payment does impose costs on the market.
- Objective (e): *to encourage the taking of measures to manage the amount of electricity used and when it is used.* MHC could see no clear impact of the proposal on the achievement of this Objective.

Efficiency objective

15. MHC's view is that the proposed Rule Change introduces two competing effects in terms of efficiency:

- the proposed Rule Change probably enhances the efficiency of the market to the extent that it reduces the quantity of capacity that is incented to be commissioned early, but
- the proposed Rule Change probably also detracts from the efficiency of the market to the extent that socialising commissioning risks removes the incentive for capacity providers to manage them effectively including, at the margin, selecting the most cost-effective options for capacity provision.

16. On balance, MHC considers that the first effect probably dominates, since the expected cost of commissioning risks is a small component of the cost of a new project. Hence we conclude that on balance the proposed Rules Change probably enhances the achievement of the Efficiency objective.
17. By the same reasoning, the proposed Rules Change would enhance the achievement of Objective d (cost minimisation), albeit to a minor extent as argued in Paragraph 14.
18. The 'early payment mechanism' as currently constructed can be interpreted as defining a quasi-product ("early-commissioned capacity", ECC hereafter) whose purpose is to mitigate residual commissioning risks currently borne by the market. How much of that product the market needs, and the value the market places on that product, have been defined only implicitly (as argued in Paragraphs 11 and 12 above). In these terms, the fundamental problem is that *no mechanism* can be expected to produce an optimum cost-benefit trade-off because no benefit information is available.

Non-discrimination objective

19. MHC's view is that the proposed Rule Change is contrary to Objective (c) because it provides for different treatment of different classes of ECC providers based only on asserted cost differences between those classes. We consider that there are two problems with this:

    - The actual costs of commissioning capacity early have not been examined with any level of rigour
    - Even accepting *prima facie* that DSM options cost less (in terms of cash costs borne by the developer and risk of late commissioning borne by the market), the absence of a robustly defined demand curve for ECC, reflecting its value to the market, means that it cannot be determined whether a competitive ECC market would clear at, above or below the marginal cost of DSM options.

20. Further, given that it is the uncertainty inherent in project commissioning timelines that gives rise to a demand for ECC in the first place, we would expect a rational ECC market to allocate ECC costs to new entrant capacity providers. If DSM is indeed less risky to commission, it would therefore pay less. Thus a mechanism that pays 'riskier' technologies to commission early is arguably perverse.

Conclusion and recommendations

Market Objective	Impact	Rationale for assessment
(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system	**Minor positive** (on balance)	Likely to reduce quantity of early-commissioned capacity (positive) BUT socialises commissioning risks (negative)
(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors.	**No impact**	
(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.	**Major negative**	The rules change is prima facie discriminatory with no evidence to suggest a market benefit from favouring one type of capacity provider over another.
(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system.	**Minor positive**	Reducing the quantity of early-commissioned capacity will reduce the total cost of capacity to the market
(e) to encourage the taking of measures to manage the amount of electricity used and when it is used	**No impact**	

21. MHC finds the most significant impact of the proposed Rule Change to be negative in terms of Objective (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.*

22. MHC notes however the likelihood that positive impacts in terms of Objectives (a) and (d) could be expected from the proposed Rule Change.

23. MHC sees no fundamental reason why the benefits available could not be achieved without the negative impacts associated with the current proposed Rule Change. If desired, the market could find a way to limit the amount of ECC procured without discriminating against a particular class of provider.

Please contact the undersigned in all matters relating to this advice.

Ben Connor

Managing Consultant – Western Australia

Marchment Hill Consulting

Agenda Item 5c: Amendments to Cost_LR (System Restart and Load Rejection) (PRC_2010_33)

1. BACKGROUND

The parameter Cost_LR covers Load Rejection Reserve and System Restart services. System Management is responsible for proposing a value for Cost_LR for the Economic Regulation Authority (ERA) to approve as part of the three-yearly Allowable Revenue reviews (clause 3.13.3B). For any year within a Review Period, System Management is able to provide the ERA with a revised value for approval for that Financial Year (clause 3.13.3C).

Under the current settlement rules any third party suppliers for System Restart will be paid as set out in their contracts. These payments will then be deducted from the total determined by the ERA in either the three yearly Allowable Revenue determination (clause 3.13.3B), or annual resets (clause 3.13.3C).

In the event that, for whatever reason, the ERA sets Cost_LR to be zero, this will currently give rise to a negative amount to be paid to Verve Energy. Effectively, that will mean that Verve Energy will be charged - actually paying the third party suppliers to supply the System Restart service. On top of making this payment Verve Energy will also be required to provide any further System Restart service in addition to the third party suppliers, as required by System Management under clause 3.11.7A, with no compensation.

Verve Energy has submitted a Pre Rule Change Discussion paper to amend the settlement rules around the provision of System Restart service. It should be noted, there is no change to the Load Rejection settlement rules.

3. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Discuss** whether Verve Energy's PRC_2010_33 should be formally submitted as Rule Change Proposal.

Agenda item 5c:

Wholesale Electricity Market
Pre Rule Change Discussion Paper

Change Proposal No: PRC_2010_33
Received date: TBA

Change requested by Electricity Generation Corporation

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Organisation:	Electricity Generation Corporation
Address:	15-17 William St Perth WA 6000
Date submitted:	TBA
Urgency:	Standard Rule Change Process
Change Proposal title:	Amendments to Cost_LR
Market Rule affected:	9.9.1, 9.9.3A (new) and 9.11.1

Introduction

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

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

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

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

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

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

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

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

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

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

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

Details of the proposed Market Rule Change

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

Background

Ancillary Services are used to guarantee the safe, secure and reliable production of electricity on the South West interconnected system (SWIS) by ensuring the system can adequately respond to real time changes in load and generation under a range of scenarios. Ancillary Services are used to control key technical characteristics of the power system such as frequency and voltage. In particular Ancillary Services:

- help maintain Power System Security (ability of SWIS to deliver energy within reliability standards);
- help maintain Power System Reliability (ability of the SWIS to withstand sudden disturbances including restoration in the case of blackout);
- facilitate orderly trading in electricity; and
- ensure that electricity supplies are of acceptable quality.

Ancillary Services are required to support the Wholesale Electricity market (WEM) but are not traded as part of the WEM. System Management is required to procure adequate quantities of these services, either from Electricity Generation Corporation (Verve Energy) resources (the default option) or on a contestable basis from independent providers (if they provide a lower cost option to Verve's facilities).

System Management will budget the cost of procuring Ancillary Services, with budgeted costs approved by the Economic Regulation Authority. However, System Management will not fund Ancillary Services. Rather, the IMO recovers the costs of the Ancillary Services from Market Participants through the WEM settlement systems, and will use the revenue received to fund Ancillary Services provided by Verve Energy and any contracted Ancillary Service providers.

In the current market design Verve Energy is the default Ancillary Service provider. System Management is however able to contract with other suppliers for any of the Ancillary Services. The settlement system is designed on this basis:

- The total cost of an Ancillary Service is:
  - Proposed by the IMO or System Management; and
  - Determined by the Economic Regulation Authority (ERA) (the ERA could approve the proposal or it could amend the total cost based on its own processes).
- Verve Energy compensation is then determined as the balance from the total after deducting the total payment to other suppliers of Ancillary Services.

In the case of System Restart the total is proposed by System Management once every three years for the ERA to determine, though there is a provision for System Management to propose a revised total amount for years 2 and 3 of the 3-year review period. These revised totals are also subject to determination by the ERA.

Issue

Under the current settlement rules any third party suppliers for System Restart will be paid as set out in their contracts. These payments will then be deducted from the total determined by the ERA, In the event that, for whatever reason, the ERA sets the System Restart cost to be zero, this will currently give rise to a negative amount to be paid to Verve Energy. Effectively, that will mean that Verve Energy will be charged - actually paying the third party suppliers to supply the System Restart service. On top of making this payment Verve Energy will also be required to provide any further System Restart service in addition to the third party suppliers, as required by System Management under clause 3.11.7A, with no compensation.

Proposal

This proposal is to amend the settlement equations to remove the anomaly of Verve Energy paying third party suppliers for System Restart when the benefit goes to the market as a whole.

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2. Explain the reason for the degree of urgency:

It is proposed that this Rule Change Proposal be progressed through the Standard Rule Change Process.

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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)

A new term ASP_Balance_Payment(i,m) has been introduced replacing the existing term ASP_Payment (i,m) in the definition for Electricity Generation Corporation AS Provider Payment(p,m). Note that ASP_Payment(i,m) continues to be used in the formula. The new term ASP_Balance_Payment(i,m) is determined in a new clause 9.9.3A

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

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

Where

the Electricity Generation Corporation AS Provider Payment(p,m) =
0 if Market Participant p is not the Electricity Generation Corporation and
(Availability_Cost_R(m) + Availability_Cost_LF(m) + Cost_LRD(m))
- Sum(i∈I, ASP_Balance_Payment(i,m)) otherwise.

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

ASP_Payment(i,m) is determined in accordance with clause 9.9.3;

ASP_Balance_Payment(i,m) is determined in accordance with clause 9.9.3A

. . .

A new clause 9.9.3A is added to define ASP_Balance_Payment(i,m) now used in clause 9.9.1. The new clause parallels the existing clause 9.9.3 except for subclause (c) for Load Rejection Reserve Service and System Restart. In this new subclause payment to Electricity Generation corporation is made non-negative.

9.9.3A. The value of ASP_Balance_Payment(i,m) for Ancillary Service Provider i in Trading Month m for determining the Ancillary Service settlement amount for the Electricity Generation Corporation is the sum of:

(a) the sum over all Ancillary Service Contracts for Spinning Reserve of ASP_SRPayment(i,m), the payment under that contract;

(b) the sum over all Ancillary Service Contracts for Load Following of ASP_LFPayment(i,m), the payment under that contract;

(c) for Ancillary Service Contracts for Load Rejection Reserve Service and System Restart:

Max(0, Cost_LR(m) – sum(i∈I, ASP_LRPayment(i,m)) – sum(i∈I, ASP_BSPayment(i,m))); and

(d) the sum over all Ancillary Service Contracts for Dispatch Support of ASP_DSPayment(i,m), the payment under that contract

Where

each of the terms ASP_SRPayment(i,m), ASP_LFPayment(i,m), ASP_LRPayment(i,m), ASP_BSPayment(i,m) and ASP_DSPayment(i,m) is determined in accordance with clause 9.9.4 and

Cost_LR(m) is the total Load Rejection Reserve Service and System Restart services payment costs for Trading Month m as specified by the IMO under clause 3.22.1(g)(i)

Having made the Load Rejection Reserve Service and System Restart payment to Electricity Generation Corporation non-negative, if the total amount determined by the Economic Regulation Authority is zero, the IMO will be short after paying the third party suppliers. The amendment to clause 9.11.1 is to recover this payment to third party suppliers from Market Customers through the Reconciliation Settlement Amount. Market Customers are not charged a second time in this process as with Cost_LR having a zero amount for Load Rejection Reserve Service and System Restart these services are not charged in clause 9.9.1.

9.11.1. The Reconciliation Settlement amount for Market Participant p for Trading Month m is:

$$RSA(p,m) = (-1) \times Consumption\_Share(p,m) \times Sum(q \in P, d \in D, t \in T, BSA(q,d,t) + NCC(q,m) + ASSA(q,m))$$

Where

ASSA(q,m) is the Ancillary Service settlement amount for Market Participant q for Trading Month m;

. . .

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

This rule change addresses a fundamental value that underwrites the market and thus the Market Objectives. It is proposed that it is inequitable for a Market Participant to be required to pay for services provided by third party Market Participants when the benefit is received by the market as a whole. In correcting this inequity the rule change should be seen as supporting the market and consistent with the Market Objectives.

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

Costs:
The IMO would require some changes to its settlement system.

Benefits:
The proposed changes will ensure Verve Energy is not required to pay for third party supplies of System Restart services for the benefit received by the market as a whole.

Agenda Item 5d: Calculation of capacity value for Intermittent Generation (RC_2010_25 and RC_2010_37)

1. BACKGROUND

The Renewable Energy Generation Working Group1 (REGWG), established under the auspices of the MAC, was tasked with the review and investigation of potential issues associated with high levels of penetration of intermittent renewable energy generation projects within the South West interconnected system (SWIS). A Work Program which broadly comprises four Work Packages was established to address these issues. Work Package 2 sought to address these issues through the development of a capacity valuation methodology that would accurately value the contribution of Intermittent Generators at times of peak demand. The REGWG did not reach consensus or compromise on the matter of valuing Capacity Credits for Intermittent Generation.

2. IMO RULE CHANGE PROPOSAL

The IMO has recommended the implementation of a proposal that assesses the average performance of the intermittent generation fleet over 12 peak Trading Intervals for each year, and then values the fleet at the 95 percent probability of exceedance of these averages from the preceding eight years. The fleet capacity value is then apportioned between the various Intermittent Generators according to their performance in the top 250 intervals during the last three years. The IMO Rule Change Proposal (RC_2010_25) is attached as appendix 1.

3. GRIFFIN ENERGY RULE CHANGE PROPOSAL

Griffin Energy has recommended the implementation of a methodology based on the average output of each Facility during the 750 Trading Intervals with the highest Load for Scheduled Generation output in each of the last three years. The Griffin Energy Rule Change Proposal (RC_2010_37) is attached as appendix 2.

4. SUMMARY OF METHODOLOGIES

A summary of these methodologies and the resultant expected capacity valuations is provided in the table below.

Proposal #	Expected capacity valuation (% of nameplate capacity)	
	Wind Farms	Solar
RC_2010_25	16 - 20 percent	40 - 50 percent
RC_2010_37	28 -34 percent	35- 45 percent

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

5. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Note** that there are two Rule Change Proposals currently in the Rule Change Process proposing alternative methodologies for calculating the capacity value for Intermittent Generation; and
- **Note** that the IMO has aligned the timeframes for these two proposals to allow stakeholders to consider and submit on both methodologies at the same time.

Independent Market Operator

Rule Change Notice

Title: Calculation of the Capacity Value of Intermittent Generation - Methodology 1 (IMO)

Ref: RC_2010_25

Standard Rule Change Process

Date: 6 December 2010

CONTENTS

DOCUMENT DETAILS

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1. THE RULE CHANGE PROPOSAL

1.1. *The Submission*

On 29 November 2010 the IMO submitted a Rule Change Proposal regarding amendments to clauses4.11.3A, 7.7.5A, 7.7.5B, 7.7.5C, 10.5.1 and new clause 4.11.3B and Appendix 9 of the Wholesale Electricity Market Rules (Market Rules).

This Rule Change Notice is published according to clause 2.5.7 of the Market Rules, which requires the Independent Market Operator (IMO) to publish a notice when it has developed a Rule Change Proposal.

1.1.1 *Submission details*

Name:	Troy Forward
Phone:	9254 4300
Fax:	9254 4399
Email:	Troy.forward@imowa.com.au
Organisation:	IMO
Address:	Level 3, Governor Stirling Tower, 197 St Georges Terrace
Date submitted:	29 November 2010
Urgency:	Standard Rule Change Process
Change Proposal title:	Calculation of the Capacity Value of Intermittent Generation – Methodology 1
Market Rule affected:	Clause 4.11.3A, 7.7.5A, 7.7.5B, 7.7.5C, 10.5.1 and new clause 4.11.3B and Appendix 9.

1.2. *Details of the Proposal*

Background

The IMO notes in its Rule Change Proposal that a key objective for the Wholesale Electricity Market (WEM) is to ensure that electricity and related services are provided reliably and economically. This is a significant challenge in Western Australia because the electricity system is isolated and supplies cannot be drawn from neighbouring systems during times of system peak demand.

The provision of capacity in Western Australia is achieved through the Reserve Capacity Mechanism (RCM). This is a set of processes through which the IMO determines the amount of generation and Demand Side Management capacity required to meet future peak system demand and reliability requirements.

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The current incentives for investment in the WEM, as provided by the RCM, distinguish broadly between Scheduled Generation and Intermittent Generation. They are as follows:

- Scheduled Generation – assigned Capacity Credits at a level equivalent to the level of electrical output produced on a sent-out basis at 41 degrees Celsius (in accordance with clause 4.11.1(a)); and

- Intermittent Generation – assigned Capacity Credits based on their average capacity factor over a three year period (in accordance with clause 4.11.2(b)[1]). This has historically equated to valuing wind farms at 38 to 42 percent of their nameplate capacity. Modelling suggests that a solar generation plant would be valued between 20 percent and 30 percent of its nameplate capacity with this method.

The IMO notes that for comparison, a wind farm investing in the National Electricity Market (NEM) is assumed to receive in the order of 5 percent of nameplate capacity for reliability planning purposes. It should be noted that the NEM does not have a capacity market and the lower valuation does not affect the income of the individual wind farms.

Given the expanded Mandatory Renewable Energy Target (MRET) scheme to achieve a national target of 20 percent of renewable generation in 2020, there is a possibility of greater momentum in renewable energy generation growth, particularly wind generation, in the South West interconnected system (SWIS). Greater renewable energy penetration in the SWIS would impact significantly on the composition of the available capacity.

Issues

The IMO notes that the intent of the RCM is to ensure that there is sufficient capacity at peak demand times. This intent is reflected in the valuation methodology for Scheduled Generators that focuses on peak demand times by assessing the sent out capacity likely to be available at an ambient temperature of 41°C. By contrast, the current methodology for Intermittent Generators, based on the three-year average output, does not focus on peak demand times and is thus not obviously aligned with the intent of the RCM. The capacity of an Intermittent Generator is subject to technology-specific constraints and risks such as weather conditions which impact on its ability to provide the required capacity during peak periods.

Given the momentum driving the growth in renewable energy providers on the SWIS, concerns have been raised regarding the current Capacity Credit valuation methodology for Intermittent Generators. Specifically:

- Doubts have been expressed as to whether the three-year average accurately represents the capacity that can be reliably delivered by wind generators. System Management, in particular, has expressed concern that excessively high valuations for wind farms could reduce the capacity available during a peak demand event and jeopardise the security of the power system.
- It has been widely acknowledged that the current valuation methodology is unsuitable for solar generation and undervalues this capacity. The current method includes overnight and winter periods that are outside peak demand times and during which solar output is low.

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[1] The IMO notes that there is no restriction on the ability of each type of technology to apply for certification in accordance with either of the Capacity Credit allocation methodologies. However, predominantly since market start Intermittent Generators have applied for certification in accordance with clause 4.11.2(b). Note that during the October 2010 MAC meeting, the MAC endorsed that the methodology for certification under clause 4.11.1(a) be limited to Scheduled Generators.

These concerns highlight the importance of ensuring that the investment signals provided by the RCM strike a balance between providing appropriate remuneration for Intermittent Generation and ensuring system security and reliability can be maintained.

Renewable Energy Generation Working Group

In light of the expected increase in Intermittent Generation capacity in the SWIS, the appropriateness of the current capacity valuation methodology for Intermittent Generation capacity has been reviewed by the Renewable Energy Generation Working Group (REGWG). The REGWG was convened by the Market Advisory Committee (MAC) at its meeting on 12 March 2008 to consider and assess system and market issues arising from increasing penetration of Intermittent Generation[2]. A work program which broadly comprised four Work Packages was established to address these issues.

Work Package 2 sought to address these issues through the development of a capacity valuation methodology that would accurately value the contribution of Intermittent Generators at times of peak demand.

A key concept that was considered and recommended was the use of Load for Scheduled Generation (LSG) when identifying the critical peak demand intervals. LSG is calculated using the load that remains after removing the level of intermittent generation in the market. The use of LSG can change the timing of critical system reliability conditions towards those times where the demand on Scheduled Generators is highest. This technique accounts for increasing penetration of Intermittent Generation and promotes diversity of technology types and location.

While failing to reach a consensus position on the matter of valuing Capacity Credits for Intermittent Generation, the REGWG supported the proposal that the IMO would nominate the valuation methodology that it felt best served the Market Objectives and would submit a Rule Change Proposal to the MAC.

Proposal

The IMO recommends the implementation of the following methodology:

1. Identify in each of the eight previous years the 12 Trading Intervals which experienced the highest LSG. For this purpose, the LSG is calculated for each Trading Interval by subtracting the output from Intermittent Generation facilities (measured output from existing facilities and modelled output where the facility had not yet entered service) from the total sent out generation during that Trading Interval.
2. For each of the eight years, determine the average output of the Intermittent Generation fleet during the 12 Trading Intervals with the highest LSG.
3. Determine the 95 percent PoE level of the eight annual averages. This is the fleet capacity value.

[2] Additional detail on the REGWG can be found on the IMO website: www.imowa.com.au/REGWG

4. Identify in each of the three previous years the 250 Trading Intervals which experienced the highest LSG.
5. Determine the average output of each individual Intermittent Generation facility for the 750 intervals determined in step 4. This is denoted below as the facility performance level.
6. Determine the sum of the facility performance levels determined in step 5. This is denoted below as the fleet performance level.
7. Apportion the fleet capacity value to each Intermittent Generation facility according to its performance over the 750 intervals.

   Relevant Level = (Facility Performance Level) / (Fleet Performance Level) × Fleet Capacity Value

The IMO notes that it has also considered the proposed amendments presented in the Draft Rule Change Report: Adjustment of the Relevant Level for Intermittent Generation (RC_2010_24). As agreed at the October 2010 MAC meeting the IMO has incorporated Alinta's proposed amendments to adjust for Trading Intervals where a Planned or Consequential Outage occurred or where output was curtailed following a request from System Management in the calculation of the highest 12 Trading Intervals for the Fleet each year. Additionally the IMO has adjusted for the incidence of Forced Outages in these intervals to avoid penalising all Non-Scheduled Generators due to Forced Outage at a single Facility.

The IMO notes that it has however excluded only periods where a Facility experiences a Consequential Outage from the determination of the 750 intervals for each individual Intermittent Generation facility. This is because instances of a Consequential Outage occurring are outside the control of a Facility. The IMO considers that it is reasonable to include all other instances of outages or curtailment following an instruction by System Management during the 750 Trading Intervals, as this will more appropriately reflect the availability of a facility during peak demand times. Network-related failures that result in a Dispatch Instruction being issued to a Facility should be reported as a Consequential Outage, and would be excluded accordingly.

The IMO considers that the proposed solution provides the following advantages:

- gives consideration to the reliability impacts of the capacity valuation methodology by valuing the intermittent generation fleet at the 95 percent PoE level;
- focuses on critical intervals of high system demand; and
- more fairly reflects the contribution of solar generation facilities to power system reliability at times of peak demand.

1.3. The Proposal and the Wholesale Market Objectives

The IMO contends in its proposal that the proposed amendments are consistent with the Wholesale Market Objectives and better address the Wholesale Market Objectives (a) and (c). In particular, the IMO considers that the proposed changes will apply a methodology to the calculation of Capacity Credits for Intermittent Generators that more appropriately reflects the contribution of a renewable generator at times of high system demand. This will:

- Promote greater system security and reliability by providing certainty to System Management that the capacity available in the market can meet peak demand requirements (Market Objective (a)); and
- Remove a current source of discrimination between Scheduled Generators and Intermittent Generators by determining the level of certification of Intermittent Generators during peak demand periods (Market Objective (c))

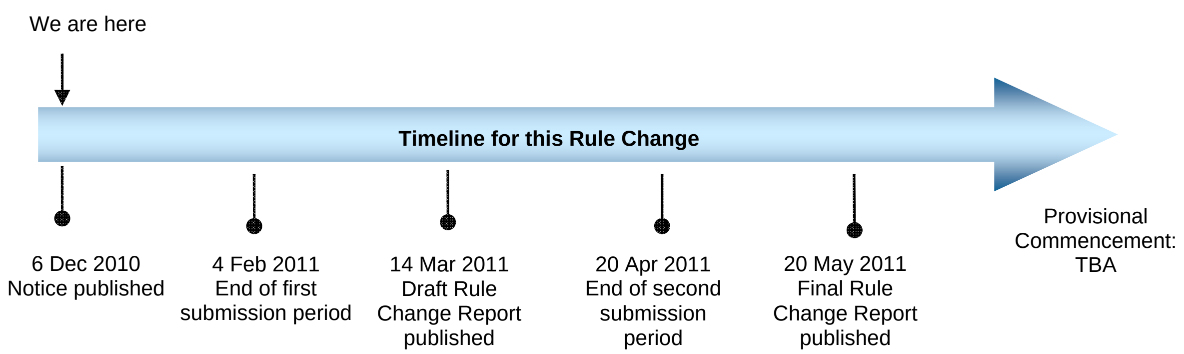
The IMO considers that the proposed changes are consistent with the other market objectives.

2. WHETHER THE PROPOSAL WILL BE PROGRESSED FURTHER

The IMO has decided to proceed with this proposal on the basis that Market Participants should be given an opportunity to provide submissions as part of the rule change process. Please note, Griffin Energy has submitted a Rule Change Proposal outlining an alternative methodology for the calculation of capacity value for Intermittent Generators (refer to RC_2010_37: Capacity Valuation for Intermittent Generators – Methodology 2). The IMO has aligned the Rule Change timelines for these two proposals so that interested stakeholders can comment on the two methodologies at the same time.

This Rule Change Proposal will be processed using the Standard Rule Change Process, described in section 2.7 of the Market Rules.

The projected timelines for processing this proposal are:



Please note that, as published in the extension notice on 6 December 2010:

- the time for the first submission period has been extended beyond the usual 30 Business Days to better align operational considerations over the Christmas period; and
- The time for publication of the Draft Rule Change Report has been extended beyond the usual 20 Business Days to take into account the other Rule Change Proposals already in the process.

All other dates have been adjusted accordingly.

3. CALL FOR SUBMISSIONS

The IMO is seeking submissions regarding this proposal. The submission period has now been extended to 40 Business Days from the publication date of this Rule Change Notice. Submissions must be delivered to the IMO by 5pm on **Friday, 4 February 2011**.

The IMO prefers to receive submissions by email to market.development@imowa.com.au using the submission form available on the IMO website: http://www.imowa.com.au/rule-changes.

Submissions may also be sent to the IMO by fax or post, addressed to:

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

Fax: (08) 9254 4399

4. PROPOSED AMENDING RULES

The IMO proposes the following amendments to the Market Rules (~~deleted text~~, added text):

The proposed amendment will specify that the IMO must determine the Relevant Level for a Facility in accordance with the methodology specified in Appendix 9.

4.11.3A. Where the IMO accepts a nomination to use the methodology prescribed in clause 4.11.2(b) to assign Certified Reserve Capacity, the IMO must determine the Relevant Level for that Facility using the methodology described in Appendix 9.

~~The Relevant Level in respect of a Facility at a point in time is determined by the IMO following these steps:~~

~~(a) take all the Trading Intervals that fell within the last three years up to, and including, the last Hot Season;~~

~~(b) determine the amount of electricity (in MWh) sent out by the Facility in accordance with metered data submissions received by the IMO in accordance with clause 8.4 during these Trading Intervals;~~

~~(c) If the Generator has not entered service, or if it entered service during the period referred to in step (a), estimate the amount of electricity (in MWh) that would have been sent out by the facility, had it been in service, for all Trading Intervals occurring during the period referred to in (a) which are prior to it entering service;~~

~~(d) set the Relevant Level as double the sum of the quantities determined in (b) and (c) divided by 52,560~~

The proposed new clause will require the IMO to conduct a five year review of the methodology for determining the Relevant Level for a Facility to ensure it is effective in its application.

4.11.3B At least once in every five year period, commencing from 1 October 2011, the IMO must conduct a review of the methodology for determining the Relevant Level for a Facility specified in clause 4.11.3A.

The proposed amendments are consistent with the amended requirement for all renewable energy generators to provide details of their fuel data for the Facility to System Management (i.e. wind data and number of turbines operating for a wind farm). The provision of wind farm data has previously been optional for Market Participants.

7.7.5A. For the purpose of determining the quantity described in clause 6.17.6(c)(i) for each Trading Interval the quantity is~~:~~

~~(a) where System Management has been provided with information in accordance with clause 7.7.5B,~~ System Management's estimate of the MWh reduction in output, by Trading Interval, of the Non-Scheduled Generator as a result of System Management's Dispatch Instruction~~; or~~

~~(b) in the case of a Non-Scheduled Generator included in a Resource Plan, for which System Management has not been provided with information in accordance with clause 7.7.5B, the greater of zero and the MWh difference between the Resource Plan MWh quantity of the Non-Scheduled Generator less the MWh output of the Non-Scheduled generator over the Trading Interval implied by its Dispatch Instruction~~.

7.7.5B. A ~~Market Participant~~ Non-Scheduled Generator ~~may~~ must provide System Management with the information specified in the Power System Operation Procedure to support System Management's ~~the~~ calculation of the quantity described in clause 7.7.5A~~(a)~~ and the IMO's estimation in Appendix 9 of the impact of Planned Outages, Consequential Outages and Forced Outages on the output, by Trading Interval, of a Facility assigned Certified Reserve Capacity in accordance with the methodology specified in clause 4.11.2(b).

7.7.5C. The Power System Operation Procedure must specify the data required to be provided by a Non-Scheduled Generator to System Management for each Facility during each Trading Interval, where this information must be ~~that actual wind data for the site of a wind farm and the number of turbines operating, if made available by a Market Participant to System Management, are~~ sufficient to allow:

a) System Management to determine, in accordance with clause 7.7.5A, what the output of ~~the~~ each Facility ~~a wind farm~~ would have been had no Dispatch Instruction or request to deviate from its Dispatch Plan or change its commitment or output been issued; and

b) the IMO to determine, in accordance with Appendix 9, what the output of the Facility would have been had a Planned Outage, Consequential Outage or Forced Outage not occurred.

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

…

(g) details of the instructions provided to:

i. Curtailable Loads that have Reserve Capacity Obligations; and

ii. providers of Supplementary Capacity;

on the Trading Day; ~~and~~

(h) the identity of the Facilities which were subject to either a Commissioning Test or a test of Reserve Capacity for each Trading Interval of the Trading Day~~.~~; and

(i) the data provided by a Market Participant in accordance with clause 7.7.5B.

The proposed amendment will allow the IMO to publish the relevant information required by Market Participants to determine their certification value. This information will be published as public information by 1 May of each year. Further details of the level of information to be published will be specified in the Market Procedure for Certification of Reserve Capacity. Note that the REGWG at its 12 August 2010 meeting agreed to progress a Rule Change Proposal to publish details of aggregate Intermittent Generator data.

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

(a) the following Market Rule and Market Procedure information and documents:

…

(f) the following Reserve Capacity information (if applicable):

i. Requests for Expressions of Interest described in clause 4.2.3 for the previous five Reserve Capacity Cycles;

…

ix. The following annually calculated and monthly adjusted ratios:

1. NTDL_Ratio as calculated in accordance with Appendix 5, STEP 8;

2. TDL_Ratio as calculated in accordance with Appendix 5, STEP 8; and

3. Total_Ratio as calculated in accordance with Appendix 5, STEP 10~~.~~; and

x. Fleet-Assessment Load for Scheduled Generation, Facility-Assessment Load for Scheduled Generation and the relevant Trading Intervals as determined under Appendix 9.

Glossary

Facility-Assessment Load for Scheduled Generation: The total sent out generation of all Facilities minus the sent out generation (measured or estimated) of Facilities which applied to be assigned Certified Reserve Capacity in accordance with clause 4.11.2(b) adjusted for the impact of Consequential Outages on those Facilities.

Fleet-Assessment Load for Scheduled Generation: The total sent out generation of all Facilities minus the sent out generation (measured or estimated) of Facilities which applied to be assigned Certified Reserve Capacity in accordance with clause 4.11.2(b) adjusted for the impact on the output of those Facilities due to Consequential Outages, Planned Outages, Forced Outages, Dispatch Instructions and deviations from Dispatch Plans due to instructions from System Management.

The proposed new Appendix 9 will specify the methodology followed by the IMO in determining each Facility's Relevant Level. Alternatively, this could be presented in a Market Procedure.

Appendix 9: Relevant Level Determination

This Appendix presents the methodology for determining the Relevant Level for a Facility which has applied for certification of Reserve Capacity in accordance with the methodology prescribed in clause 4.11.2(b).

The IMO must perform the following steps in determining the Relevant Level for Facility in accordance with clause 4.11.3A:

Determining the Fleet Capacity Value

Step 1: Take all the Trading Intervals that occurred with the eight year period ending on the Trading Day ending on 1 April of Year 1 of the relevant Reserve Capacity Cycle.

Step 2: Determine the amount of electricity (in MWh) sent out by all Facilities applying for Certified Reserve Capacity under clause 4.11.2(b) using the Meter Data Submissions received by the IMO in accordance with clause 8.4 during the Trading Intervals identified in step 1.

Step 3: Identify any Trading Intervals in step 1 where a Facility, as identified in step 2, either:

a) was owned, controlled or operated by a Market Participant other than the Electricity Generation Corporation and was issued a Dispatch Instruction from System Management as notified under clause 7.13.1(c); or

b) was owned, controlled or operated by the Electricity Generation Corporation and was issued an instruction from System Management to deviate from its Dispatch Plan or change its commitment or output as notified under clause 7.13.1(cC); or

c) was affected by a Forced Outage, Planned Outage or Consequential Outage as notified under clause 7.13.1A; or

Step 4: If, as identified in step 3 (a), a Facility's output was reduced in order to comply with a Dispatch Instruction from System Management, issued in accordance with clause 7.7, use:

a) the estimated decrease (in MWh) in the output of each Facility, by Trading Interval, as a result of System Management Dispatch Instructions, provided by System Management in accordance with clause 7.13.1(eB); and

b) the amount of electricity (in MWh) sent out for the Facility in accordance with the Metered Data Submissions received by the IMO in accordance with clause 8.4 for all the Trading Intervals that were identified under step 3 (a)(ii.),

to estimate the amount of electricity (in MWh) that would have been sent out by the Facility, had it not complied with the Dispatch Instruction for all the Trading Intervals identified under step 3(a)(ii.). Use these estimated values to replace the amount of electricity identified in step 2 for the relevant Trading Intervals.

Step 5: If, as identified in step 3 (b), a Facility's output was reduced in order to comply with an instruction from System Management under clause 7.6A.3(a) to deviate from its Dispatch Plan or change its commitment or output, use:

a) the estimated decrease (in MWh) in the output of that Facility, by Trading Interval, as a result of an instruction from System Management in accordance with clause 7.6A.3(a), provided by System Management in accordance with clause 7.13.1(eD); and

b) the amount of electricity (in MWh) sent out for that Facility in accordance with the Meter Data Submissions received by the IMO in accordance with clause 8.4 for all the Trading Intervals that were identified under step 3 (b)(ii.),

to estimate the amount of electricity (in MWh) that would have been sent out by that Facility had it not complied with System Management's instruction for all the relevant Trading Intervals that were excluded under step 3 (b)(ii). Use these estimated values to replace of the amount of electricity identified in step 2 for all the relevant Trading Intervals identified in step 3.

Step 6: If, as identified in step 3 (c), a Facility's output was reduced due to a Forced Outage, Planned Outage or Consequential Outage, as notified under clause 7.13.1A, use:

a) the schedule of Planned Outages, Consequential Outages and Forced Outages provided by System Management in accordance with clause 7.3.4 and 7.13.1A;

b) the amount of electricity sent out for that Facility in accordance with the Meter Data Submissions received by the IMO in accordance with clause 8.4 for all the Trading Intervals that were identified under step 3 (a) (i) and step (b) (i); and

c) the data provided by System Management in accordance with clause 7.13.1(i),

to estimate the amount of electricity (in MWh) that would have been sent out by that Facility had it not experienced a Forced Outage, Planned Outage or Consequential Outage . Use these estimated values to replace of the amount of electricity identified in step 2 for all the relevant Trading Intervals identified in step 3.

Step 7: If a Facility has not yet entered service, or if it entered service during the period referred to in step 1, use the estimates included in the expert report provided in accordance with clause 4.10.3 for the period that Facility was not in service, unless the IMO reasonably believes the report to be inaccurate.

Step 8: Determine, for each Trading Interval during the period described in step 1, the Fleet-Assessment Load for Scheduled Generation by subtracting the sent out generation contribution of all Facilities which applied to be certified under clause 4.11.2(b), as identified in step 2 and updated under steps 4, 5, 6 and 7 as applicable ("Fleet Interval Performance Level"), from the total sent out generation of all Facilities for each Trading Interval.

Step 9: Determine for each year during the period identified in step 1, the 12 Trading Intervals with the highest Fleet-Assessment Load for Scheduled Generation as identified under step 8.

Step 10: Determine for each year during the period identified in step 1, the mean of the Fleet Interval Performance Level ("Fleet Annual Mean Performance Level") during the 12 Trading Intervals identified under step 9.

Step 11 Determine using a t-distribution the mean ("Fleet Mean") and standard deviation ("Fleet SD") of the Fleet Annual Mean Performance Levels for the period identified in step 1.

Step 12: Determine the **Fleet Capacity Value (MW)** by calculating the 5 percent Probability of Exceedance level in accordance with the following formula:

Fleet Capacity Value = 2 x (Fleet Mean – (1.895 x Fleet SD))

Step 13: If the value for the Fleet Capacity Value determined under step 12 is equal to or less than zero then set the Fleet Capacity Value equal to zero.

Determining the Facility Performance Level

Step 14: Take all the Trading Intervals that occurred within the last three year period ending on the Trading Day ending on 1 April of Year 1 of the relevant Reserve Capacity Cycle.

Step 15: Determine the amount of electricity (in MWh) sent out by the Facility using the Meter Data Submissions received by the IMO in accordance with clause 8.4 during the Trading Intervals identified in step 14.

Step 16: Identify any Trading Intervals in step 15 where the Facility was affected by a Consequential Outage as notified under clause 7.13.1A.

Step 17 If, as identified in step 16, the Facility's output was reduced due a Consequential Outage, use

a) the schedule of Consequential Outages a provided by System Management in accordance with clause 7.3.4 and 7.13.1A;

b) the amount of electricity sent out for the Facility in accordance with the Meter Data Submissions received by the IMO in accordance with clause 8.4 for all the Trading Intervals that were identified under step 16; and

c) the data provided by System Management in accordance with clause 7.13.1(i),

to estimate the amount of electricity (in MWh) that would have been sent out by the Facility had it not experienced a Consequential Outage for all the relevant Trading Intervals identified in step 16.

Step 18: If the Facility has not yet entered service, or if it entered service during the period referred to in step 15, use the estimates included in the expert report provided in accordance with clause 4.10.3 for the period that the Facility was not in service, unless the IMO reasonably believes the report to be inaccurate.

Step 19: Determine for each Trading Interval during the period described in step 14 the Facility-Assessment Load for Scheduled Generation by subtracting the sent out generation contribution of all Facilities which applied to be certified under clause 4.11.2(b), as identified in step 15 and updated under steps 17 and 18 as applicable, from the total sent out generation of all Facilities for each Trading Interval.

Step 20: Determine for each year during the period identified in step 14, the 250 Trading Intervals with the highest Facility-Assessment Load for Scheduled Generation as identified under step 19.

Step 21: Determine the **Facility Performance Level** for each Facility that applied to be certified under clause 4.11.2(b). The Facility Performance Level for Facility f is the mean of that Facility's sent out generation during the 750 Trading Intervals identified under step 15 and updated under steps 17 and 18, as applicable.

Determining the Relevant Level for a Facility

Step 22: Determine the Relevant Level for each Facility f (in MW) in accordance with the following formula:

Relevant Level(f) = Facility Performance Level(f) / Sum(f∈F, Facility Performance Level(f)) × Fleet Capacity

Where

F is the set of all Facilities which applied to be certified under clause 4.11.2(b), where "f" is a member of that set.

Step 21. Publish the Fleet-Assessment Load for Scheduled Generation. Facility-Assessment Load for Scheduled Generation and relevant Trading Intervals identified in steps 1, 9 and 14 on the Market Web Site by 1 May of the relevant year.

5. ABOUT RULE CHANGE PROPOSALS

Clause 2.5.1 of the Market Rules provides that any person (including the IMO may make a Rule Change Proposal by completing a Rule Change Proposal Form and submit this to the IMO.

The IMO will assess the proposal and, within 5 Business Days of receiving the proposal form, will notify the proponent whether the proposal will be progressed further.

In order for the proposal to be progressed the change proposal must explain how it will enable the Market Rules to better contribute to the achievement of the Wholesale Market Objectives. The market objectives 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.

A Rule Change Proposal can be processed using a Standard Rule Change Process or a Fast Track Rule Change Process. The standard process involves a combined 10 weeks public submission period, while the fast track process involves the IMO consulting with Rule Participants who either advise the IMO that they wish to be consulted or the IMO considers have an interest in the change.

Independent Market Operator

Rule Change Notice

Title: Calculation of the Capacity Value of Intermittent Generation - Methodology 2 (Griffin Energy)

Ref: RC_2010_37

Standard Rule Change Process

Date: 6 December 2010

CONTENTS

DOCUMENT DETAILS

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1. THE RULE CHANGE PROPOSAL

1.1. The Submission

On 30 November 2010 Griffin Energy submitted a Rule Change Proposal regarding amendments to clauses 4.11.3A, 7.7.5B, 7.7.5C, 7.7.5E, 7.13.1, 10.5.1 and the Glossary of the Wholesale Electricity Market Rules (Market Rules).

This Rule Change Notice is published according to clause 2.5.7 of the Market Rules, which requires the Independent Market Operator (IMO) to publish a notice when it has developed a Rule Change Proposal.

1.1.1 Submission details

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Date submitted:	30/11/2010
Urgency:	Standard Rule Change Process
Change Proposal title:	Calculation of the Capacity Value of Intermittent Generation – Methodology 2
Market Rule affected:	Clauses 4.11.3A, 7.7.5B, 7.7.5C, 7.7.5E, 7.13.1,10.5.1 and the Glossary.

1.2. Details of the Proposal

Griffin Energy notes in its Rule Change Proposal that a key outcome for the Wholesale Electricity Market (WEM) is to ensure that electricity and related services are provided reliably and economically.

The Long Term Projected Assessment of System Adequacy (PASA) is a process through which the Independent Market Operator (IMO) determines the amount of capacity required to meet future peak system demand and reliability requirements.

The Reserve Capacity Mechanism (RCM) provides incentives for investment in capacity in the WEM, and distinguishes broadly between Scheduled Generation and Intermittent Generation.

- Scheduled Generation – assigned Capacity Credits at a level equivalent to the level of electrical output produced on a sent-out basis at 41 degrees Celsius (in accordance with clause 4.11.1(a)); and

- Intermittent Generation – assigned Capacity Credits based on their average capacity factor over a three year period (in accordance with clause 4.11.2(b)1).[1] This has historically equated to valuing wind farms at 38 to 42 percent of their nameplate capacity. Modelling suggests that a solar generation plant would be valued between 20 percent and 30 percent of its nameplate capacity with this method.

The expanded Mandatory Renewable Energy Target (MRET) scheme has a national target for renewable generation to comprise 20 percent of all generation by 2020. As a result, it is expected that capacity (and energy) from renewable energy generation, particularly wind generation, will grow in the South West Interconnected System (SWIS).

Issues

Griffin Energy notes that in the Planning Criteria used by the IMO in undertaking the Long Term PASA, there should be sufficient available capacity in each Capacity Year during the planning horizon to:

1. meet forecast peak demand, plus a reserve margin; and

2. limit expected energy shortfalls to 0.002 per cent of annual energy consumption.

The methodology for assigning Capacity Credits to Scheduled Generators focuses on meeting forecast peak demand by assessing the sent out capacity likely to be available at an ambient temperature of 41°C.

Griffin Energy however contends that the current methodology for assigning Capacity Credits to Intermittent Generators, which is based on the three-year average output, does not necessarily relate to the output of Intermittent Generators in peak demand periods. Rather, it is orientated towards the contribution that Intermittent Generators make to limiting expected annual energy shortfalls.

Given the expected increase in Intermittent Generation on the SWIS, Griffin Energy notes that the following concerns have been raised about the current methodology used to assign Capacity Credits to Intermittent Generators.

- System Management has suggested that the current methodology overstates the energy that wind farms can be expected to make available during periods of peak demand, and that as a result the methodology has the potential to jeopardise the security of the power system.
- The current methodology is unsuitable for solar generation because it includes overnight and winter periods during which solar output would be expected to be low. As these periods are generally outside periods of peak demand, the current methodology may undervalue the energy that solar can be expected to make available during periods of peak demand.

[1] While there is no restriction on the ability of each type of technology to apply for certification in accordance with either of the Capacity Credit allocation methodologies, since market start Intermittent Generators have predominantly applied for certification in accordance with clause 4.11.2(b).

Renewable Energy Generation Working Group

The Renewable Energy Generation Working Group (REGWG) was convened by the Market Advisory Committee (MAC) at its meeting on 12 March 2008 to consider and assess system and market issues arising from increasing penetration of Intermittent Generation.

A work program which broadly comprised four Work Packages was established to address these issues. Work Package 2 sought to develop a methodology that would accurately value the contribution of intermittent generators during periods of peak demand. McLennan Magasanik Associates (MMA) was appointed to undertake Work Package 2.

A key concept that was considered and recommended was the use of Load for Scheduled Generation (LSG) when identifying the critical peak demand intervals. LSG is calculated using the load that remains after removing the level of intermittent generation in the market.

The use of LSG can change the timing of critical system reliability conditions towards those times where the demand on Scheduled Generators is highest. This technique accounts for increasing penetration of Intermittent Generation and promotes diversity of technology types and location. LSG has been incorporated into each of the valuation methodologies explained below.

MMA, through its analysis, recommended a methodology based upon the average output of each facility in 750 peak intervals for selected high demand years, which are scaled to future load forecasts. This methodology delivers valuations of between 35 percent and 40 percent of nameplate capacity for the existing wind farms, and between 50 percent and 60 percent for the modelled solar generation facilities. A more simple and transparent variant of this methodology, using 750 Trading intervals from the last three years, was also considered and was known as Proposal 2B. Proposal 2B is expected to deliver valuations of between 30 percent and 35 percent of nameplate capacity for the existing wind farms, and between 35 percent and 50 percent for the modelled solar generation facilities.

System Management expressed concern that this methodology relied on simulated data, and that, being based on an average performance level, did not represent the capacity that could reliably be delivered by Intermittent Generators.

Consequently, System Management proposed an alternative methodology that assessed the value of the fleet at the 90 percent probability of exceedance (PoE) level of the top 1 percent of Trading Intervals during the last three years (175 Trading Intervals per year). It then proportioned this fleet capacity value between the various Intermittent Generators according to their performance in the top 250 intervals during the last three years. The methodology proposed by System Management would deliver valuations of between 6 percent and 17 percent of nameplate capacity for the existing individual wind farms, and between 10 percent and 30 percent for the modelled solar generation facilities.

The Office of Energy proposed a further alternative methodology that would assess the average performance of the intermittent generation fleet over 12 peak Trading Intervals for each year, and then value the fleet at the 95 percent PoE level of these averages from the preceding eight years. The fleet capacity value would then be apportioned between the various Intermittent

Generators according to their performance in the top 250 Trading Intervals during the last three years. The Office of Energy's methodology is estimated to deliver valuations of between 16 percent and 20 percent of nameplate capacity for existing wind farms and between 40 percent and 50 percent for the solar generation facilities modelled.

Throughout the REGWG process, System Management maintained that valuations higher than around 20 per cent[2] of nameplate capacity could compromise the reliability of the power system.
System Management's views were countered by various REGWG members, including Market Participants with existing Intermittent Generation facilities (Alinta, Griffin Energy), proponents of new Intermittent Generation facilities (Pacific Hydro, Mid West Energy) and Synergy. These members supported Proposal 2A (or its variant 2B), suggesting that this proposal, developed and recommended by an expert consultant, has the strongest scientific basis and strongest link to system reliability. They also indicated that any reduction in the capacity valuation for Intermittent Generators would harm investment in the renewable energy sector in the SWIS and increase the perceived regulatory risk of investing in the WEM.

The IMO suggested Proposal 1 at the 2 September 2010 REGWG meeting, which was supported by LGP on the basis that it is a compromise between the other proposals. System Management indicated that it could accept Proposal 1 provided that the valuation did not exceed 20 percent of nameplate capacity. This was not supported by the other parties advocating Proposal 2A or 2B.

While failing to reach a consensus position on the matter of valuing Capacity Credits for Intermittent Generation, the REGWG supported the proposal that the IMO would recommend a way forward to the MAC[3]. The IMO has indicated to the MAC that it proposes to submit a rule change proposal based on Proposal 1 – the Office of Energy 'compromise' methodology.

Griffin Energy notes that itself - along with a number of other stakeholders with considerable interests in maintaining a viable investment environment in the SWIS, as well as ensuring long term system reliability - consider that the compromise methodology of Proposal 1 will create unnecessary distortions in the market. Importantly, Griffin Energy considers that:

1. The MMA Proposals 2A and 2B provide an explicit mechanism that will self regulate the contribution of intermittent generation to system peak periods in the SWIS. If an intermittent facility fails to produce energy during the periods when most required (i.e. when scheduled generation is at peak output under the LSG concept – likely during summer peak demand periods), then the quantity of capacity credits allocated to the facility will be reduced and other generation facilities (or DSM) will be required to meet the IMO demand forecast.

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[2] It is unclear if this represented a blanket capacity credit cap for all intermittent generation, or would be applied to each intermittent facility (wind, wave or solar), irrespective of the underlying renewable resource.
[3] While minuted as such, it was not my recollection that the REGWG agreed that the IMO would develop a rule change proposal for submission to the MAC, rather that it would provide a recommendation on what to do next.

2. The issue of system reliability, in the face of an expected increase in intermittent generation in the SWIS, it better managed through re-setting the system reserve margin and/or the expected energy shortfall limits. This will have the same effect of decreasing the quantity of capacity credits to intermittent facilities in that a greater capital stock of generation (or DSM) will be required to meet the same IMO demand forecast, but without distorting the market for, or disincentivising investment in intermittent generation in the SWIS[4].

Proposal

Griffin Energy proposes to change the current methodology for allocating capacity credits for intermittent generators in the Market Rules to that based on Proposal 2B, developed by MMA for the REGWG. While not as technically proficient as Proposal 2A (MMA's preferred methodology), Griffin Energy considers it delivers the following benefits:

- balances consideration of both the reliability <u>and</u> unserved energy impacts of the capacity valuation methodology with respect to the IMO Planning Criterion by only awarding capacity credits to intermittent generation facilities based on their output during periods of highest demand on scheduled generation (using the top 750 LSG intervals in a year);
- uses recent historical data averaged out over three years to smooth any annual variation;
- is the simplest and most transparent methodology;
- is the most consistent with the current methodology; and
- more fairly reflects the contribution of solar generation facilities to power system reliability at times of peak demand.

Griffin Energy specifically proposes the following methodology:

1. Identify the top 750 Trading intervals associated with the highest Load for Scheduled Generation output in each of the three previous years.

2. For each of the 2,250 intervals identified in Step 1, determine the metered output of the intermittent generation facility (or the estimated output if the facility is experiencing a Planned or Consequential Outage or where its output was curtailed following a request from System management).

[4] It should be noted that there will be little likelihood of too much intermittent generation being built in the SWIS to meet a greater reserve margin. In our market, all intermittent generation technologies require offtake agreements for the energy they produce. As there will only ever be a finite requirement for new energy to meet load growth, there will also be a finite quantity of intermittent generation capable of being financed. The remainder of reserve capacity requirement will likely be met by scheduled peaking generation or DSM.

3. Double the value determined in Step 2 and divide this number by 2,250. The result is the Relevant Level for that facility (or is the quantity of capacity credit allocated to that facility).

Griffin Energy notes that its proposal includes the proposed amendments presented in the Draft Rule Change Report: Adjustment of the Relevant Level for Intermittent Generation (RC_2010_24). Griffin Energy notes that Alinta's proposed amendments under RC_2010_24 adjust for Trading Intervals where a Planned or Consequential Outage occurred or where output was curtailed following a request from System Management.

1.3. The Proposal and the Wholesale Market Objectives

Griffin Energy considers the proposed amendments to the Market Rules will have the following affect on the market objectives:

Objective	Impact
a)	The proposed changes will promote greater reliability as the quantity of Capacity Credits received by an Intermittent Generator is closely aligned with the peak summer demand periods, when system reliability is most at risk. The changes will also promote economic efficiency by rewarding intermittent generation facilities a suitable quantity of Capacity Credits relative to other generation facilities, ensuring investment in generation technologies is optimised in the WEM.
b)	The proposed changes will promote competition among new entrant generators (including those with advanced intermittent projects under development) as it is relatively consistent with the current Capacity Credit allocation methodology and does not distort the market for new generation investment.
c)	The proposed changes lessen the discrimination between Scheduled Generation and Intermittent Generation in that Intermittent Generation is now also awarded Capacity Credits based on output during higher (summer) demand periods. The proposed changes also lessen the discrimination between Intermittent Generation technologies by ensuring all technologies have their capacity allocation assessed by their contribution during peak (summer) demand periods.
d)	The proposed changes will *prima facie* increase the long term cost of electricity in the WEM as any expected reduction in Capacity Credits from Intermittent Generation facilities (compared with the current allocation methodology) will mean that further generation facilities (or DSM) will need to be constructed (or contracted) to meet the same IMO forecast demand, hence raising the cost to end users. The proposed changes however may also assist in reducing the cost of electricity in that, assuming renewable energy facilities are to be constructed to meet federal MRET targets, intermittent facilities that are incentivised to produce energy during high demand periods will likely offset expensive peaking scheduled generation, bringing down wholesale energy prices in the STEM and balancing markets during the summer period.

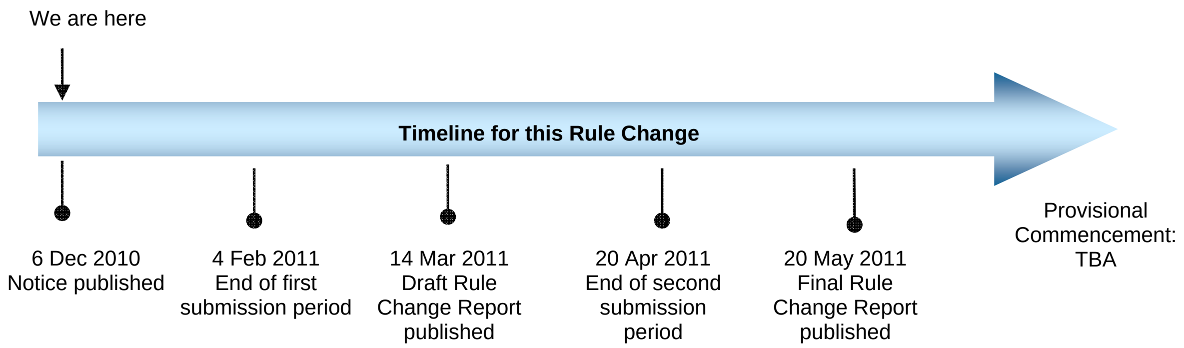
e)	The proposed changes may lead to benefits in that energy storage options will be incentivised and implemented more quickly as storage technologies become economically viable.

2. WHETHER THE PROPOSAL WILL BE PROGRESSED FURTHER

The IMO has decided to proceed with this proposal on the basis that Market Participants should be given an opportunity to provide submissions as part of the rule change process. Please note, the IMO has submitted a Rule Change Proposal outlining an alternative methodology for the calculation of capacity value for Intermittent Generators (refer to RC_2010_25: Capacity Valuation for Intermittent Generators – Methodology 1). The IMO has aligned the Rule Change timelines for these two proposals so that interested stakeholders can comment on the two methodologies at the same time.

This Rule Change Proposal will be processed using the Standard Rule Change Process, described in section 2.7 of the Market Rules.

The projected timelines for processing this proposal are:



Please note that, as published in the extension notice on 6 December 2010:

- the time for the first submission period has been extended beyond the usual 30 Business Days to better align operational considerations over the Christmas period; and
- The time for publication of the Draft Rule Change Report has been extended beyond the usual 20 Business Days to take into account the other Rule Change Proposals already in the process.

All other dates have been adjusted accordingly.

3. CALL FOR SUBMISSIONS

The IMO is seeking submissions regarding this proposal. The submission period has now been extended to 40 Business Days from the publication date of this Rule Change Notice. Submissions must be delivered to the IMO by 5pm on **Friday, 4 February 2011**.

The IMO prefers to receive submissions by email to market.development@imowa.com.au using the submission form available on the IMO website: http://www.imowa.com.au/rule-changes.

Submissions may also be sent to the IMO by fax or post, addressed to:

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

Fax: (08) 9254 4399

4. PROPOSED AMENDING RULES

Griffin Energy proposes the following amendments to the Market Rules (~~deleted text~~, added text):

4.11.3A. The Relevant Level in respect of a Facility at a point in time is determined by the IMO following these steps:

(a) take ~~all~~ the top 750 Facility-Assessment Load for Scheduled Generation Trading Intervals that fell within each of the last three years up to, and including, the last Hot Season, excluding any Trading Intervals where the Facility either:

i. was owned, controlled or operated by a Market Participant other than the Electricity Generation Corporation and:

1. was affected by a Planned Outage or Consequential Outage as notified under clause 7.13.1A; or

2. was issued a Dispatch Instruction from System Management as notified under clause 7.13.1(c); or

ii. was owned, controlled or operated by the Electricity Generation Corporation and:

1. was affected by a Planned Outage or Consequential Outage as notified under clause 7.13.1A; or

2. was issued an instruction from System Management to deviate from its Dispatch Plan or change its commitment or output as notified under clause 7.13.1(cC);

(b) determine the amount of electricity (in MWh) sent out by the Facility in accordance with ~~meter data submissions~~ Meter Data Submissions received by the IMO in accordance with clause 8.4 during these Trading Intervals;

(c) ~~I~~if the ~~Generator~~ Facility has not entered service, or if it entered service during the period referred to in step (a), estimate in accordance with the Reserve Capacity Procedure the amount of electricity (in MWh) that would have been sent out by the ~~f~~Facility, had it been in service, for ~~all~~ the top 750 Facility-Assessment Load for Scheduled Generation Trading Intervals occurring during the period referred to in step (a) which are prior to it entering service;

(cA) if, during the period described in step (a), the Facility's output was reduced in order to comply with a Dispatch Instruction from System Management, issued in accordance with clause 7.7, use:

i. the estimated decrease (in MWh) in the output of each Facility, by Trading Interval, as a result of System Management Dispatch Instructions, provided by System Management in accordance with clause 7.13.1(eB); and

ii. the amount of electricity (in MWh) sent out for the Facility in accordance with the Metered Data Submissions received by the IMO in accordance with clause 8.4 for all the Trading Intervals that were excluded under step (a)(ii.), to estimate the amount of electricity (in MWh) that would have been sent out by the Facility, had it not complied with the Dispatch Instruction for all the Trading Intervals that were excluded under step (a)(ii.).

(cB) if, during the period described in step (a), the Facility's output was reduced in order to comply with an instruction from System Management under clause 7.6A.3(a) to deviate from its Dispatch Plan or change its commitment or output, use:

i. the estimated decrease (in MWh) in the output of each Facility, by Trading Interval, as a result of an instruction from System Management in accordance with clause 7.6A.3(a), where this information has been either:

a. provided by System Management in accordance with clause 7.13.1(eD) for the relevant Trading Intervals that were excluded under step (a), where actual data for the site of the Facility has been provided to System Management under clause 7.7.5B; or

b. determined by the IMO in accordance with the Reserve Capacity Procedure for all the relevant Trading Intervals that were excluded under step (a), where actual data for the site of the Facility has not been made available to System Management under clause 7.7.5B; and

ii. the amount of electricity (in MWh) sent out for the Facility in accordance with the Meter Data Submissions received by the IMO in accordance with clause 8.4 for all the Trading Intervals that were excluded under step (a)(iii.), to estimate the amount of electricity (in MWh) that would have been sent out by the Facility had it not complied with System Management's instruction for all the relevant Trading Intervals that were excluded under step (a)(iii.); and

(d) set the Relevant Level as double the sum of the quantities determined in steps (b), ~~and~~ (c), (cA) and (cB) divided by the sum of the Trading Intervals identified in steps (a), (cA) and (cB) ~~52,560~~.

7.7.5B. A ~~Market Participant~~ Non-Scheduled Generator ~~may~~ must provide System Management with the information specified in the Power System Operation Procedure to support System Management's ~~the~~ calculation of the quantity described in clause 7.7.5A~~(a)~~ and 7.7.5E.

7.7.5C The Power System Operation Procedure must specify the data required to be provided by a Non-Scheduled Generator to System Management for each Facility during each Trading Interval, where this information must be ~~that actual wind data for the site of a wind farm and the number of turbines operating, if made available by a Market Participant to System Management, are~~ sufficient to allow System Management to determine, in accordance with clause 7.7.5A, what the output of ~~the~~ each Facility ~~a wind farm~~ would have been had no Dispatch Instruction or request to deviate from its Dispatch Plan or change its commitment or output been issued.

7.7.5E. Where the Electricity Generation Corporation has made actual wind data available in accordance with clause 7.7.5B and the Power System Operation Procedure, System Management must estimate the decrease, in MWh, in the output of each Electricity Generation Corporation Facility as a result of a instruction from System Management to deviate from its Dispatch Plan or change its commitment or output in accordance with clause 7.6A.3(a).

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

…

(c) a schedule of all of the Dispatch Instructions other than instructions with respect to Registered Facilities to which clauses 3.21A.14 or 4.25.10 apply, that System Management issued for each Trading Interval in the Trading Day by Market Participant and Facility, including the information specified in clause 7.7.3, or as agreed between the IMO and System Management;

(cA) a schedule of the MWh output of each generating system monitored by System Management's SCADA system for each Trading Interval of the Trading Day;

(cB) the maximum daily ambient temperature at the site of each generating system monitored by System Management's SCADA system for the Trading Day;

(cC) a schedule of all instructions provided to the Electricity Generation Corporation's Non-Scheduled Generators to deviate from its Dispatch Plan or change its commitment of output in accordance with clause 7.6A.3 for each Trading Interval of the Trading Day;

…

(eB) the estimated decrease, in MWh, in the output of each Non-Scheduled Generator, by Trading Interval, as a result of System Management Dispatch Instructions, as determined in accordance with clause 7.7.5A, where this is to be used in settlement as the quantity described in clause 6.17.6(c)(i)~~.~~;

(eC) the required decrease, in MWh, in the consumption of each Curtailable Load, by Trading Interval, as a result of System Management Dispatch Instructions, where this is to be used in settlement as the quantity described in clause 6.17.6(d)(i)~~.~~;

(eD) the estimated decrease, in MWh, in the output of each Electricity Generation Corporation Non-Scheduled Generator as a result of a instruction from System Management to deviate from its Dispatch Plan or change its commitment or output in accordance with clause 7.6A.3(a), as determined in accordance with clause 7.7.5E, where this is to be used in the calculation of the Relevant Level described in clause 4.11.3A;

…

(g) details of the instructions provided to:

i. Curtailable Loads that have Reserve Capacity Obligations; and

ii. providers of Supplementary Capacity;

on the Trading Day; ~~and~~

(h) the identity of the Facilities which were subject to either a Commissioning Test or a test of Reserve Capacity for each Trading Interval of the Trading Day.; and

(i) the data provided by a Market Participant in accordance with clause 7.7.5B.

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

(a) the following Market Rule and Market Procedure information and documents:

…

(f) the following Reserve Capacity information (if applicable):

i. Requests for Expressions of Interest described in clause 4.2.3 for the previous five Reserve Capacity Cycles;

…

ix. The following annually calculated and monthly adjusted ratios:

1. NTDL_Ratio as calculated in accordance with Appendix 5, STEP 8;

2. TDL_Ratio as calculated in accordance with Appendix 5, STEP 8; and

3. Total_Ratio as calculated in accordance with Appendix 5, STEP 10.; and

x. Facility-Assessment Load for Scheduled Generation.

Glossary

Facility-Assessment Load for Scheduled Generation: The total sent out generation of all Facilities minus the sent out generation (measured or estimated) of Facilities which applied to be assigned Certified Reserve Capacity in accordance with clause 4.11.2(b) adjusted for the impact of Consequential Outages on those Facilities.

5. ABOUT RULE CHANGE PROPOSALS

Clause 2.5.1 of the Market Rules provides that any person (including the IMO may make a Rule Change Proposal by completing a Rule Change Proposal Form and submit this to the IMO.

The IMO will assess the proposal and, within 5 Business Days of receiving the proposal form, will notify the proponent whether the proposal will be progressed further.

In order for the proposal to be progressed the change proposal must explain how it will enable the Market Rules to better contribute to the achievement of the Wholesale Market Objectives. The market objectives 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.

A Rule Change Proposal can be processed using a Standard Rule Change Process or a Fast Track Rule Change Process. The standard process involves a combined 10 weeks public submission period, while the fast track process involves the IMO consulting with Rule Participants who either advise the IMO that they wish to be consulted or the IMO considers have an interest in the change.

imo Independent Market Operator

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

Legend:

Shaded	Shaded rows indicate procedure changes that have been completed since the last MAC meeting.
Unshaded	Unshaded rows are procedure changes still being progressed.

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
IMO Procedure Change Proposals					
PC_2010_03	Monitoring Protocol	The proposed updates are to: • Allow the IMO to disclose the identity of System Management as a participant that notifies us of alleged breaches; and • Update to conform to recently adopted style changes.	• Submission period.	• Submission period ends.	16 December 2010
PC_2010_05	Reserve Capacity Performance Monitoring	The proposed updates are to: • Include the changes to the Amending Rules arising from RC_2010_11, RC_2009_19 and RC_2010_02; • Update to conform to recently adopted style changes.	• Submission period.	• Submission period ends.	13 December 2010
PC_2010_06	Certification of Reserve Capacity	The proposed updates are to: • ensure that an appropriate amount of CRC for each Facility is set, and allow the IMO to determine the	• Due to commence	• Commencement	15 December 2010

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
		viability of a new project and its prospects of proceeding through to completion before the start of the relevant Capacity Year • specify the steps for applying for and approving Early Certified Reserve Capacity. This will ensure consistency with the Rule Change Proposal: Early Certified Reserve Capacity (RC_2009_10); and • improve the integrity of the Market Procedure by including a number of minor and typographical amendments.			
PC_2010_07	Market Procedure for Web Site Changes	The proposed updates are to: • Updated to the new IMO procedures format; • expand the associated market documents to include the confidentiality status document (step 1.4.2); and • note the process where System Management has not been delegated the authority to directly post information or documents on the Market Web Site (step 2.1.1).	• Submission period.	• Submission period ends.	13 December 2010
PC_2010_08	Supplementary Reserve Capacity (SRC)	The proposed new Market Procedure describes the process that the IMO and System Management will follow in: • acquiring Eligible Services, • entering into SRC Contracts; • determining the maximum contract value per hour of availability for any contract; and • Details the information that is required to be exchanged. This Market Procedure needs to be published (as required by the Market Rules) and will be revised following any rule changes (if applicable).	• Submission period.	• Submission period ends.	20 December 2010

System Management Procedure Change Proposals					
PPCL0016	Monitoring and Reporting Protocol	The proposed updates are to provide further details around how System management will determine and review the annual Tolerance Range and any Facility Tolerance Ranges to apply for the purposes of clause 7.10.1 and 3.21 of the Market Rules. The proposed updates will ensure consistency with the requirements of RC_2009_22 and in particular the new clause 2.13.6K.	Discussed at Working Group Meeting (28 October 2010)	• System Management to submit into the Procedure Change Process.	TBD
TBD	Dispatch	The proposed updates are to allow for discretion to be exercised in requesting daily dispatch profiles from Market participants with facilities smaller than 30 MW.	Discussed at Working Group Meeting (28 October 2010)	• System Management to submit into the Procedure Change Process.	TBD
TBD	Facility Outages	The proposed update is to amend the procedure to reflect the commenced RC_2010_05 'Confidentiality of Accepted Outages by System Management'.	Discussed at Working Group Meeting (28 October 2010)	• System Management to submit into the Procedure Change Process.	TBD
TBD	Commissioning and Testing	The proposed update is to amend the procedure to reflect the commenced RC_2010_37 'Equipment Tests'.	Discussed at Working Group Meeting (28 October 2010)	• System Management to submit into the Procedure Change Process.	TBD

Agenda Item 6b: Supplementary Reserve Capacity Market Procedure (PC_2010_08)

1. BACKGROUND

The Wholesale Electricity Market Rules require the IMO to document the procedures it follows it:

- acquiring Eligible Services for supplementary reserve capacity (SRC);
- entering into Supplementary Capacity Contracts; and
- determining the maximum contract value per hour of availability for any Supplementary Capacity Contract.

The proposed new SRC Market Procedure (attached as appendix 1 to this paper) has been discussed by the IMO Market Procedures Working Group at the 13 August 2009, 22 April 2010 and 26 October 2010 meetings[1].

The IMO considers that, as this is a new Market Procedure, the MAC should have the opportunity to discuss while it is out for consultation, which closes 20 December 2010.

2. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Note** the new SRC Market Procedure.

[1] Minutes from the meetings are available on the IMO's website: http://www.imowa.com.au/IMO-Procedures-Working-Group

MARKET PROCEDURE: Supplementary Reserve Capacity

VERSION 1

Independent Market Operator

ELECTRICITY INDUSTRY ACT 2004

ELECTRICITY INDUSTRY
(WHOLESALE ELECTRICITY MARKET)
REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

COMMENCEMENT:

This Market Procedure took effect from 8:00am (WST) on the
Xx Xxx 2010.

VERSION HISTORY

VERSION	EFFECTIVE DATE	NOTES
1	Xx Xxx 2010	New Market Procedure for Supplementary Reserve Capacity resulting from PC_2010_08

CONTENTS

1 PROCEDURE OVERVIEW

1.1 Relationship with the Market Rules

1.1.1 This Supplementary Reserve Capacity (SRC) Market Procedure (Procedure) should be read in conjunction with section 4.24 and clause 4.25.4F of the Wholesale Electricity Market (WEM) Rules (Market Rules).

1.1.2 Reference to particular Market Rules within the Procedure in bold and square brackets **[MR XX]** are current as of 1 October 2010. These references are included for convenience only, and are not part of this Procedure.

1.2 Purpose

1.2.1 This Procedure describes the steps the IMO and System Management must follow in:

a) acquiring Eligible Services;

b) entering into Supplementary Capacity Contracts; and

c) determining the maximum contract value per hour of availability for any Supplementary Capacity Contract.

1.3 Application

1.3.1 This Procedure applies to the IMO and System Management.

1.4 Associated Market Procedures

1.4.1 The following IMO Market Procedures are associated with this Procedure:

a) Reserve Capacity Testing;

b) Undertaking the LT PASA and conducting a review of the Planning Criterion;

c) Settlements; and

d) Operational Financial Contingency.

1.5 Interpretation

1.5.1 In this Procedure the conventions specified in clauses 1.3- 1.5 of the Market Rules apply.

1.6 General Notes

1.6.1 SRC may only be provided by "Eligible Services" identified in clause 4.24.3 of the Market Rules **[MR 4.24.3]**.

1.6.2 A Curtailable Load that has had its Capacity Credits reduced in response to a request from the relevant Market Participant, in accordance with clause 4.25.4C of the Market Rules, is not an Eligible Service **[MR4.25.4F]**.

1.6.3 Market Participants may not offer SRC from a Registered Facility that has had its Capacity Credits reduced due to a failed Reserve Capacity test, in accordance with clause 4.25.4, for any part of the current Capacity Year.

1.6.4 The term of any Supplementary Capacity Contract is not to exceed 12 weeks **[MR 4.24.13 (h)].**

1.6.5 Payment for SRC is determined based on:

a) the availability price which is provided to a generation facility[1] for entering into the contract and making the agreed capacity available; and

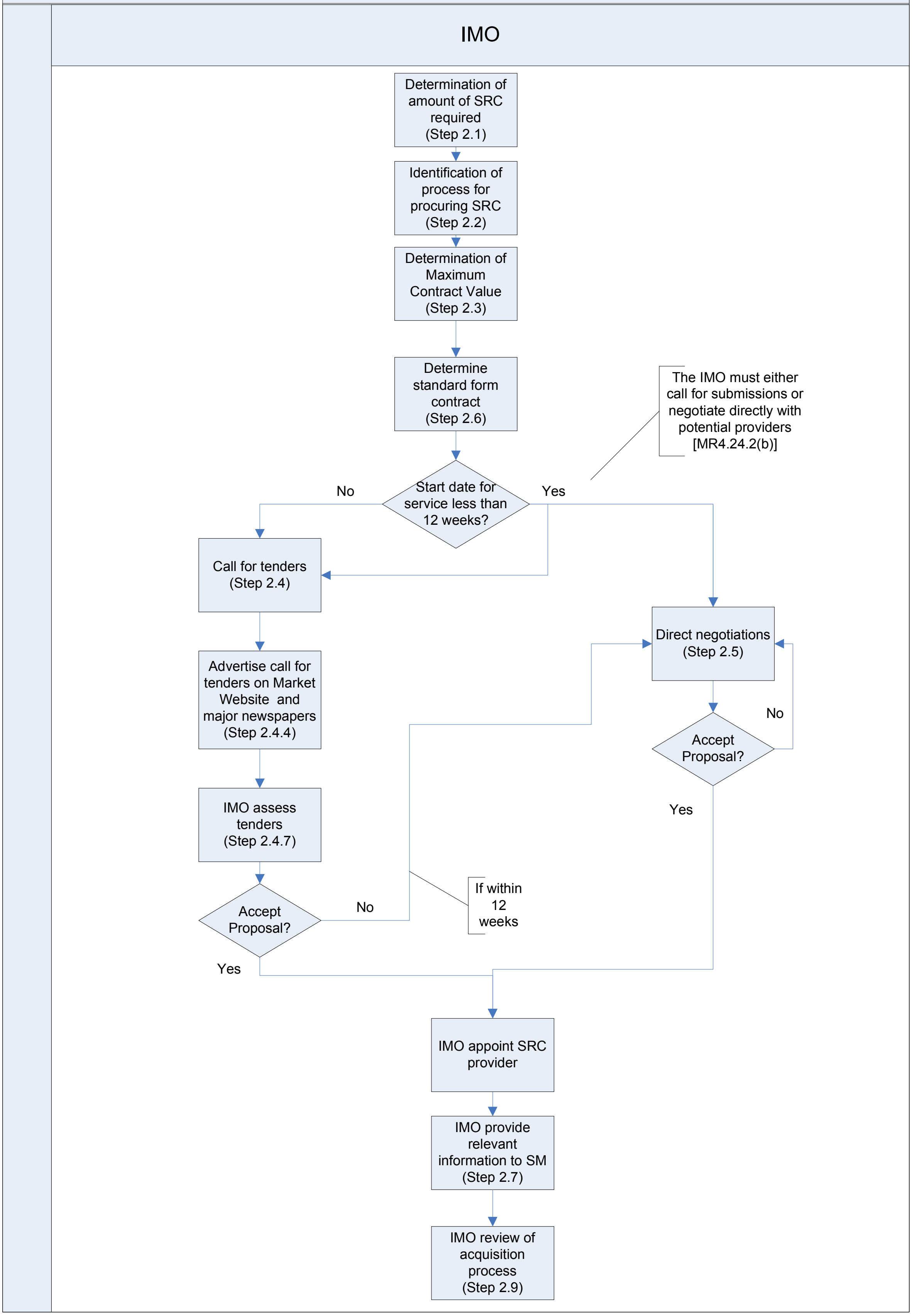
b) the activation price which applies only when the service is called upon.

2 PROCEDURE STEPS

This section outlines the procedure steps associated with the acquisition of, and entering into Supplementary Capacity Contracts for, SRC services. The diagram on the next page gives an overview of the process. Details of the associated sections of this Procedure are also indicated.

[1] No availability price will apply for load reduction facilities (see step 2.3.2 of this Market Procedure).

Acquisition of SRC



2.1 Determination of the amount of SRC Required

2.1.1 In determining the amount of SRC that is required and the associated timeframes, the IMO will:

a) identify the actual level of Certified Reserve Capacity that will be available by reference to the level of Certified Reserve Capacity less any predicted plant outages, as published in the Medium Term Projected Assessment of System Adequacy;

b) identify the level of Certified Reserve Capacity required to satisfy the SWIS reliability requirements, as set out in clauses 4.5.9(a) and 4.5.9(b) of the Market Rules;

c) determine the amount of SRC required by calculating the amount by which the quantity identified in step 2.1.1 b) exceeds the quantity identified in step 2.1.1 a) **[MR4.24.1(b)]**;

d) determine the expected start and end dates for which the amount of SRC calculated in step 2.1.1 c) will be required **[MR4.24.1 (a)]**;

e) determine the number of hours over the contract period during which SRC is expected to be required; and

f) determine the time of day when the SRC is expected to be required.

2.1.2 To assist in determining the amount of SRC, and associated timeframes, required:

a) the IMO must consult with System Management; and

b) the IMO may consult with Market Participants.

2.2 Determination of the process to be used to secure SRC

2.2.1 If the expected start date of the shortfall is at least 12 weeks from the date the IMO becomes aware of the shortfall, then it must call for tenders from potential suppliers of SRC in an invitation to tender **[MR4.24.2(a)].**

2.2.2 If the expected start date of the shortfall is less than 12 weeks from the date the IMO becomes aware of the shortfall, then the IMO must either:

a) call for tenders from potential suppliers of SRC in an invitation to tender; or

b) negotiate directly with potential suppliers of SRC **[MR4.24.2(b)]**.

2.2.3 If the IMO decides to call for tenders it must follow the process set out in Section 2.4 of this procedure.

2.2.4 If the IMO decides to negotiate directly with potential suppliers it must follow the process set out in section 2.5 of this Procedure.

2.3 Determination of the Maximum Contract Value

2.3.1 The following steps will be undertaken to determine the Maximum Contract Value for generation facilities.

a) The notional availability price in dollars per megawatt ($/MW) is calculated in accordance with the following formula:

$P_{av}(P_{RC}, d) = P_{RC} * d / x$

Where:

P_{RC} is the Reserve Capacity Price for the Capacity Year for which the SRC is being procured in dollars per megawatt ($/MW);

d is the term of the SRC contract in days, which is capped at 84 days (12 weeks) **[MR4.24.12(h)(i)]**; and

x is 121 days, which is the length of the Hot Season.

b) The notional activation price is calculated as double the Alternative Maximum STEM Price in dollars per megawatt hour ($/MWh).

c) The Maximum Contract Value in dollars per megawatt per hour ($/MW/hr) is calculated in accordance with the following formula:

$MCV(P_{av}, P_{ac}, d) = (P_{av} + (P_{ac} * t)) / t$

Where:

P_{av} is the notional availability price determined in step 2.3.1(a), in dollars per megawatt ($/MW);

P_{ac} is the notional activation price determined in step 2.3.1(b), in dollars per megawatt hour ($/MWh); and

t is the number of hours during which the capacity is expected to be required as determined in step 2.1.1(e).

d) In order to ensure sufficient incentive for a provider of an Eligible Service to activate that service, the IMO may stipulate that the availability price must not exceed a given percentage of the contract value. The IMO may set the Maximum Availability Percentage at any value up to:

$MAP(P_{av}, CV, t) = P_{av} / (CV * t) * 100$

Where:

P_{av} is the notional availability price determined in step 2.3.1(a), in dollars per megawatt ($/MW);

CV is the Contract Value proposed by the provider of an Eligible Service as determined in step 2.4.6, in dollars per megawatt per hour ($/MW/hr); and

t is the number of hours during which the capacity is expected to be required as determined in step 2.1.1(e).

2.3.2 The Maximum Contract Value for load reduction facilities will be based on the value of lost load. This will be determined by the IMO, having regard to the value of the "market price cap" as specified in clause 3.9.4(b) of the National Electricity Rules[2]. No availability price will apply for load reduction facilities.

2.4 Acquisition of SRC via a Tender Process

2.4.1 These process steps are to be followed if the IMO seeks to acquire SRC via a tender process.

2.4.2 The IMO must not call for tenders for SRC earlier than six calendar months prior to the calendar month in which the shortfall period is expected to start **[MR4.24.5]**.

2.4.3 The IMO must prescribe the tender form to be used by those applying to provide Eligible Services. This form must require the specification of:

a) the name and contact details of the applicant;

b) the nature of the Eligible Service to be provided;

c) the amount of the Eligible Service available;

[2] A copy of the National Electricity Rules is available on the following webpage: http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html

d) the maximum number of hours over the term of the Supplementary Capacity Contract that the Eligible Service will be available;

e) the maximum number of hours on each day during the term of the Supplementary Capacity Contract that the Eligible Service will be available;

f) the time of each day during the term of the Supplementary Capacity Contract that the Eligible Service will be available;

g) any information required to complete the relevant standard form Supplementary Capacity Contract for the Eligible Service and the applicant, together with full details of any amendments to the standard form Supplementary Capacity Contract required by the applicant;

h) the mechanism for activating the Eligible Service;

i) the mechanisms available for measuring the Eligible Service provided; and

j) the values of:

  i. the availability price for the Eligible Service expressed in dollars; and

  ii. the activation price for the Eligible Service, expressed in dollars per hour of activation, where this price must reflect direct or opportunity costs incurred,

  where:

  iii. the Contract Value, determined in step 2.4.6, must not exceed the Maximum Contract Value per hour of availability specified in the advertisement for the call for tenders under clause 4.24.6(g) **[MR4.24.7]**; and

  iv. the availability price divided by the Contract Value, determined in step 2.4.6, multiplied by 100 may not exceed the Maximum Availability Percentage determined in step 2.3.1(d); and

k) the timelines associated with the tendering process.

2.4.4 No earlier than 30 Business Days and no later than 10 Business Days prior to the proposed closing date for submission of tenders, the IMO must advertise the call for tenders on the Market Web Site and in major local and national newspapers **[MR4.24.6]**.

2.4.5 The advertisement must include:

a) the date and time at which any person wishing to tender to supply Eligible Services must have completed and lodged with the IMO the form specified in step 2.4.3 above.

b) contact details for the IMO;

c) the amount of capacity required;

d) the number of hours over which the capacity is expected to be used;

e) the time of the day where the capacity is expected to be required;

f) the expected term of any Supplementary Capacity Contracts entered into as a result of the call for tenders;

g) the Maximum Contract Value per hour of availability for any Supplementary Capacity Contract that the IMO will accept;

h) the Maximum Availability Percentage, where applicable;

i) the location of copies of the standard form Supplementary Capacity Contracts on the Market Web Site; and

j) the location on the Market Web Site of the tender form to be used in applying to provide Eligible Services **[MR4.24.6].**

2.4.6. The Contract Value for an Eligible Service is calculated as the availability price multiplied by the lesser of:

a) the number of hours specified in the advertisement for the call for tenders under clause 4.24.6(d); and

b) the number of hours specified for the Eligible Service in accordance with step 2.4.3(d);

plus the activation price.

2.4.7 The IMO will assess all tenders following its internal procurement policy and advise tenderer's of its outcome (in accordance with the timelines specified in the tender documentation).

2.4.8 The IMO is not under any obligation to accept any tender, or enter into a Supplementary Capacity Contract in respect of any tender, made in response to a call for tenders **[MR4.24.9]**.

2.5 Acquisition of SRC by Negotiation

2.5.1 These process steps are to be followed if the IMO seeks to acquire SRC via negotiation.

2.5.2 If the IMO negotiates directly with a potential supplier of Eligible Services then it must provide the following information to the potential supplier:

a) the amount of capacity required;

b) the relevant standard form Supplementary Capacity Contract; and

c) details of the information to be provided by the potential supplier, including:

i. the amount of the Eligible Service available;

ii. the mechanism for activating the Eligible Service;

iii. the mechanisms available for measuring the Eligible Service provided;

iv. the availability price for the Eligible Service expressed in dollars; and

v. the activation price for the Eligible Service, expressed in dollars per hour of activation, where this price must reflect direct or opportunity costs incurred. **[MR4.24.10]**

2.5.3 The IMO may accept or reject any proposals for the acquisition of SRC obtained by way of direct negotiation.

2.6 Standard Form Supplementary Capacity Contract

2.6.1 The IMO must develop and maintain a standard form Supplementary Capacity Contract which accords with the requirements in clause 4.24.13 of the Market Rules **[MR4.24.12]**.

2.6.2 The standard form Supplementary Capacity Contract will require the supplier of an Eligible Service to reduce net consumption, or to increase generation, on instruction from System Management and must specify:

a) that there are no force majeure conditions;

b) the settlement process to be followed, including timing of payments;

c) contract variation conditions;

d) any conditions required to ensure that if a different person takes over the facility used to provide the Eligible Service, that the person taking over will be bound by the contract obligations (for example, by requiring the execution of a deed of assumption or novation);

e) the financial consequences of failing to supply the Eligible Service in accordance with the contract, based on the arrangements which apply under clause 4.26 where a Market Participant holding Capacity Credits for a Facility fails to comply with its Reserve Capacity Obligations;

f) a condition allowing the IMO to disclose the information required by Market clause 4.24.16 and preventing the disclosure set out in clause 4.24.17;

g) the technical standards and verification arrangements which facilities used to provide Eligible Services must comply with; and

h) blank schedules specifying:

    i. the term of the Supplementary Capacity Contract, where this term is not to exceed 12 weeks;

    ii. the sources of the net consumption reduction or generation increase;

    iii. the amount of net consumption reduction or generation increase required;

    iv. the notification time to be given for activation;

    v. the method of notification of activation;

    vi. the minimum duration of any activation;

    vii. the maximum duration of any single activation;

    viii. any limits on the number of times System Management can request activation;

    ix. the basis to be used for measuring the response;

    x. the availability price;

    xi. the activation price;

    xii. technical matters relating to the facility (including testing); and

xiii. the fact that activation instructions will be given by System Management **[MR4.24.13].**

2.6.3 This standard form Supplementary Capacity Contract will be available on the Market Web Site in the event that the IMO decides to acquire SRC via a tender process.

2.6.4 Despite the existence of the standard form Supplementary Capacity Contract, the IMO may enter into Supplementary Capacity Contracts in any form it considers appropriate **[MR4.24.14].**

2.7 Information to be provided to System Management

2.7.1 The IMO must provide the following Supplementary Capacity Contract information to System Management, so as to allow System Management to dispatch the contracted Eligible Services:

a) the identity of each contracted Eligible Service, listed in order of increasing activation price;

b) the information required to contact the party which will activate the Eligible Service;

c) the process to be followed in activating that Eligible Service, including required advance notification times; and

d) the limitations on the availability of the Eligible Service **[MR4.24.16]**.

2.7.2 The IMO must not provide the following Supplementary Capacity Contract information to System Management for any Eligible Service:

a) the activation price for that Eligible Service; or

b) the availability price for that Eligible Service **[MR4.24.17]**.

2.8 Settlement Process

2.8.1 Settlement of SRC Contracts will be through the non-STEM settlement system.

2.8.2 The IMO must recover the full cost it incurs in respect of Supplementary Capacity Contracts in accordance with clause 4.28 and Chapter 9 of the Market Rules **[MR4.24.15]**.

2.9 Process following each call for SRC or acquisition of Eligible Services

2.9.1 Following each call for tenders for supplementary capacity or otherwise acquiring Eligible Services, the IMO must review the SRC provisions in section 4.24 of the Market Rules.

2.9.2 This review must:

a) have regard to the Wholesale Market Objectives; and

b) undertake a public consultation process in respect of the outcome of the review **[MR 4.24.19]**.

2.9.3 Following the review the IMO may propose amendments to the Market Rules and this Procedure (if applicable).

Agenda Item 7a: Working Group Overview

1. WORKING GROUP OVERVIEW

Working Group (WG)	Status	Date commenced	Date concluded	Latest meeting date	Next scheduled meeting date
Reserve Capacity 2007 WG	Closed	Feb 07	May 07	-	-
NTDL WG	Closed	Oct 07	Nov 07	-	-
Energy Limits WG	Closed	Dec 07	Jan 08	-	-
DSM WG	Closed	Jan 08	May 08	-	-
SRC WG	Closed	Jun 08	Sept 08	-	-
Reserve Capacity 2008/09 WG	Closed	Dec 08	Jan 09	-	-
Renewable Energy Generation WG	Closed	Mar 08	Nov 10	11/11/2010	-
System Management Procedures WG	Active	Jul 07	Ongoing	28/10/2010	TBA
IMO Procedures WG	Active	Dec 07	Ongoing	26/10/2010	02/02/2011
Maximum Reserve Capacity Price WG	Active	May 10	Ongoing	15/09/2010	TBA
Rules Development Implementation WG	Active	Aug 10	Ongoing	23/11/2010	14/12/2010

Agenda Item 7b: MRCPWG Update

1. OVERVIEW OF PROGRESS TO DATE

The Maximum Reserve Capacity Price Working Group (MRCPWG) last met on 15 September 2010. The IMO will be scheduling the next Working Group early in 2011 after being unable to arrange a suitable meeting time in December.

At the next meeting, the Working Group will consider the two Consultant draft reports covering the methodologies for determining the Weighted Average Cost of Capital (WACC) and Deep Connection Costs.

The MRCPWG has previously completed reviewing the cost components, though noting those which require the further advice of the Consultants. The following elements have been agreed by the MRCPWG to date:

- The appropriate power station type is an Open Cycle Gas Turbine with low NOx burners and inlet cooling, operating on distillate with 2% capacity factor;
- The appropriate quantity of capacity is 160 MW, provided as a single 160 MW facility;
- The summer de-rating factor (SDF) should be specified by the Consultant who develops the power station costs, according to available turbine and inlet cooling technology, and taking into account humidity conditions, replacing the value of 1.18 currently indicated in the Market Procedure;
- Western Power is the appropriate party to determine transmission connection costs;
- The IMO should continue to determine the WACC with the ERA reviewing this in its approval of the MRCP in accordance with clause 2.26.1 of the Market Rules;
- The Fixed Fuel Cost should include an allowance to maintain sufficient fuel levels for 14 hours of operation at all times, not 12 hours as currently indicated in the Market Procedure;
- The current methodology for determining Fixed Operation and Maintenance Costs is appropriate;
- Landgate is the appropriate party to provide a valuation on Land costs;
- The current list of land locations is appropriate, although there should be greater flexibility to add to the list where appropriate;
- Uplift factors for construction costs in the current list of locations should be specified by the Consultant;
- Land, Transmission and Construction Costs should be optimised to determine the cheapest location;
- A Market Participant may not be required to purchase any required buffer zone if the facility was located in an industrial precinct, so the land size should be standardised to 3 ha with the stipulation that the buffer zone must exist where required; and

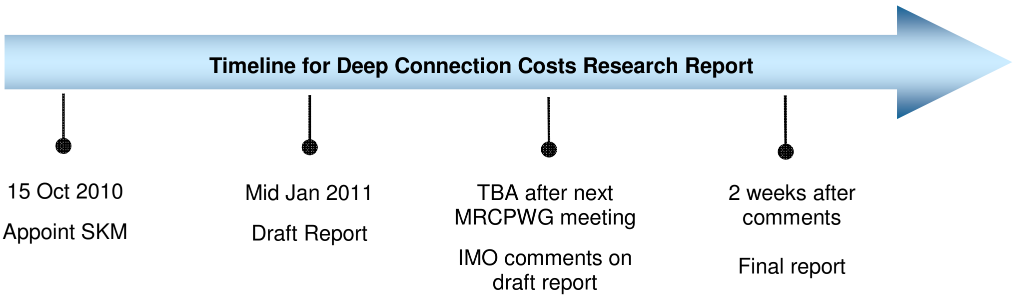
The IMO Board in interested in the work of the MRCPWG and has requested a copy of its Terms of Reference.

2. APPOINTMENT OF CONSULTANTS

2.1 Calculation methodology to be applied in determining Deep Connection Costs

The IMO has appointed SKM to prepare a review report, in the context of the Western Australian Wholesale Electricity Market (WEM), on an appropriate calculation methodology for Western Power to follow when estimating deep connection costs associated with connecting a power station to the South West interconnected system (SWIS).

A timeline detailing the remaining project steps is outlined below, this timeline has changed since it was last presented to the MAC:

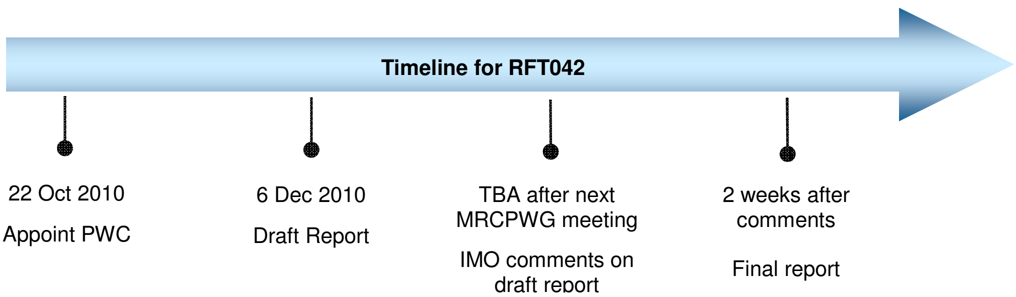


SKM has developed an alternative methodology and has requested additional information from Western Power to assess and validate the methodology.

2.2 Calculation methodology to be applied in determining Weighted Average Cost of Capital

The IMO has appointed PricewaterhouseCoopers (PWC) to provide a review report, in the context of the WEM, to the IMO on the calculation and application of an appropriate WACC for the determination of the MRCP.

A timeline detailing the remaining project steps is outlined below, this timeline has changed since it was last presented to the MAC:



3. RECOMMENDATIONS

It is recommended that the MAC **notes** this update.

Agenda item 8:

Wholesale Electricity Market

Concept Paper Proposal Form

Concept Proposal No: *CP_2010_02*
Received date: *6 December 2010*

Concept requested by

Name:	Phil Kelloway
Phone:	(08) 9427 5761
Fax:	
Email:	Phil.kelloway@westernpower.com.au
Organisation:	System Management
Address:	
Date submitted:	*6 December 2010*
Urgency:	*3-high*
Concept proposal title:	Ancillary Services Market Proposal
Market Rule(s) affected:	TBD

Introduction

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

The objectives of the market are:

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

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

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

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

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

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

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

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

General Information about Concept Paper Proposals

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

1. Log the proposal and notify the proposer that it has been received;

2. Assess the concept and consult with the Market Advisory Committee (MAC) for prioritisation against other Rule Participant issues registered; and

3. Work cooperatively with the proposer to develop the full concept paper including:

   - assessment against the Market Objectives; and
   - undertaking a detailed cost benefit analysis related to the identified options.

Details of the proposed Concept Paper

1. INTRODUCTION AND OBJECTIVES

Since commencement of the WEM in 2006, factors that are likely to contribute to significant and sustained increases in the requirement for Load Following Ancillary Services ('LFAS') have become increasingly apparent. System Management's view is that addressing this will require a coordinated and effective market based approach to the procurement of LFAS. Broadening the pool of potential providers is necessary to ensure that System Management ('SM') continues to have access to the service in the quantities that will become necessary in the short to medium term.

This paper represents SM's view on how this could be achieved in a way that is simple and which encourages participants to enter the market for LFAS provision. It draws together information presented to a range of potential participants as well as the Independent Market

Operator ('IMO') and the Economic Regulation Authority ('ERA') in a series of discussions initiated by SM between September and November 2010. For interested parties who were not involved in those discussions, SM is available to provide this more detailed presentation on request

The concept involves an additional market 'submissions window' run after the closure of the Resource Plan window and extending the current WEM scheduling day. On the trade day, successful bidders would be dispatched automatically via Automatic Generator Control ('AGC') and settled as part of the normal non-STEM settlement process.

Although, the LFAS market could be implemented with minimal or no impact on existing WEM Balancing and Reserve Capacity market processes, the final design will need to account for other market evolution processes such as the proposed move to a competitive balancing regime.

Given the simplicity of the approach discussed here this would not be a difficult issue and to ensure that all interdependent issues are given appropriate consideration in the various design processes, SM believes that it would be preferable to progress both work streams in parallel.

2. BACKGROUND

A range of stakeholders have identified the development of a more open and competitive procurement framework for Ancillary Services as a priority for the market evolution process.

In the MREP ballot carried out by the Independent Market Operator (the 'IMO') in 2009, the IMO and SM rated the issue second and third respectively amongst 16 options. Participants also identified market based AS procurement as a significant issue requiring attention, although it was generally rated slightly lower by them.

Although the Economic Regulation Authority's (the 'ERA') was not a respondent to the MREP ballot, in its 2008 Wholesale Electricity Market report to the Minister, the ERA noted that it "*strongly supports further moves towards competitive procurement of Ancillary Services.*"

Responding to these views, SM conducted an Expressions of Interest process between December 2009 and 26 February 2010 in which it requested proposals to supply a discrete tranche of LFAS. No expressions were received in that process because the structure of the EOI included explicit limitations on overall remuneration. It also used the MCAP price, which is not calculated until after the event, in settlement calculations.

The imposition of a ceiling on possible returns, and the risk inherent in MCAP, both of which are mandated within the existing Market Rules, were not viewed by the market as being conducive to a commercially attractive return for their involvement.

Recognizing that significant market rule changes would be required to successfully implement competitive LFAS procurement, System Management presented an options paper *'Future procurement of Spinning Reserve and Load Following*,' to the MAC on 16 June 2010. The paper proposed three options to improve the current Load Following Ancillary Services procurement framework. MAC members agreed that option 3, which involved the establishment of a day-ahead Ancillary Services trading market was preferred.

This concept paper is the next step in that process.

2.1 Current Regulatory Framework

Section 41(e) of the *Electricity Corporations Act (2005)* confers an obligation upon System Management to provide Ancillary Services.

The process by which SM implements this obligation derives from the *Wholesale Electricity Market Amending Rules (September 2006)* (**Market Rules**). Specifically, MR 2.2.2(a) obliges System Management to procure adequate Ancillary Services where the Electricity Generation Corporation cannot meet the Ancillary Service Requirements;

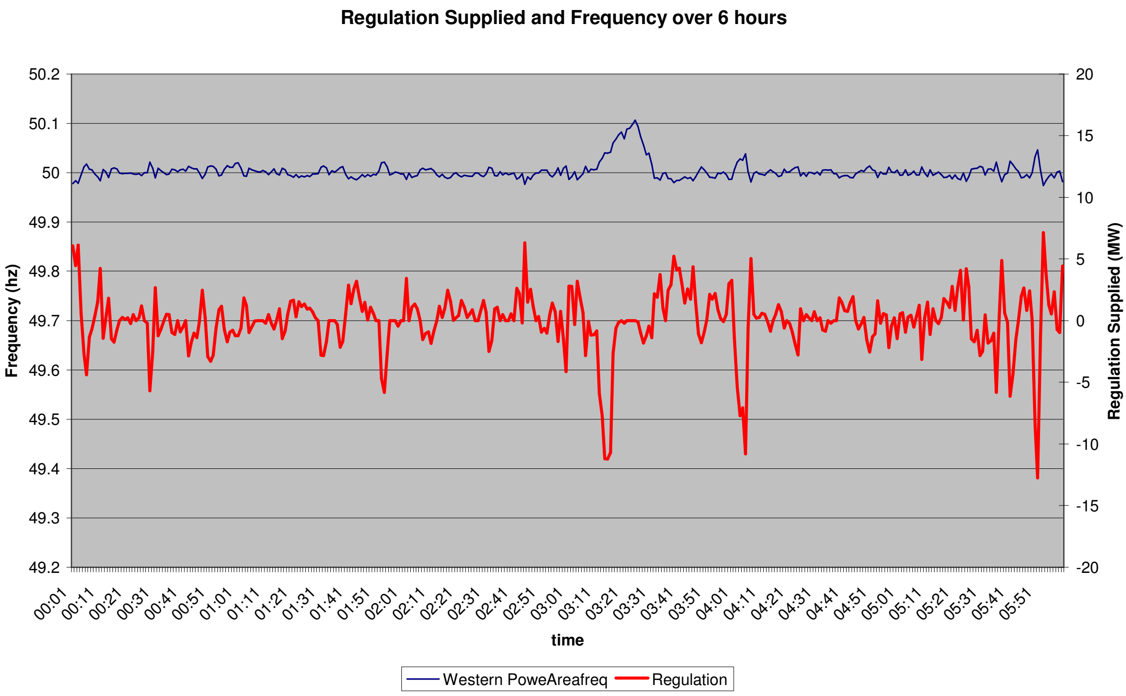
MR 3.11.8, which allows System Management to enter into an LFAS contract with a Rule Participant other than Verve Energy, provides a framework for System Management to procure LFAS where it does not consider it can meet its requirements with Verve Energy or the contract provides a less expensive alternative.

2.2 Definition of Load Following Ancillary Service

A Load Following Ancillary Service is a service to match total system generation to total system load in real time (net of intermittent generation), on a minute-by-minute basis, in order to maintain SWIS frequency standards.

Being a provider of this service entails handing over control of the load setpoint of a facility to SM who vary a scheduled generator's output around its resource plan in response to the need to manage system frequency. Real time control is through Automatic Generator Control ('AGC') systems. AGC does not replace normal governor response of the generator as required by the Technical Rules, but rather complements its action with a slower outer control loop.

The following diagram is an example of the output profile that would be expected of participants who have won the right to supply LFAS to System Management.

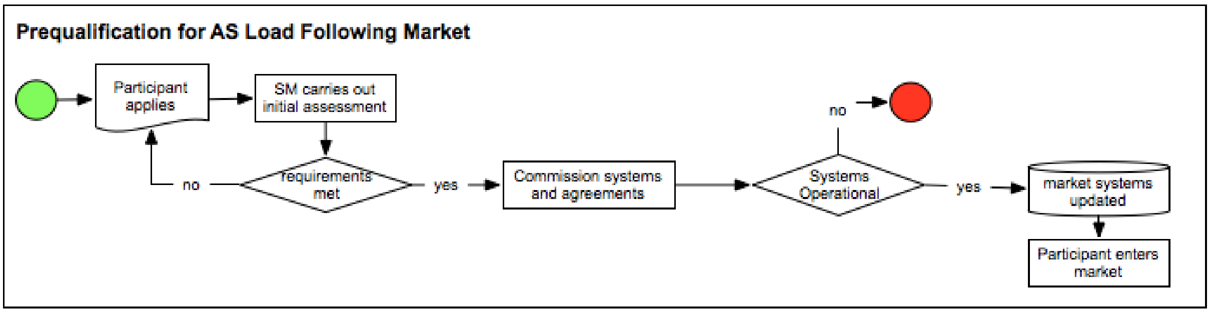


3. COMPONENTS OF A SIMPLE LFAS MARKET

The following discussion assumes no changes to the existing market rules. To the extent that changes to balancing or reserve capacity mechanisms also move into the detailed design stage, the broad design brief that is set out below would need to be reviewed for consistency with the new arrangements.

Because of the simplicity of this market this would not be a difficult process and the best integration between all of the changes is likely to be achieved if the various design processes were progressed in parallel.

3.1 LFAS Prequalification



This process relates to the registration of participants leading to their acceptance as potential LFAS providers. In relation to the LFAS market, this process is called 'Prequalification' to differentiate it from the existing registration processes that are currently administered by the IMO under the market rules.

Prequalification should be considered separately from existing market registration processes because SM will be required to take a significantly more active role in assessing the technical capability of facilities to provide the service. Entry to the market will also need to be co-ordinated by SM.

To enter the LFAS market a Participant must demonstrate its facility's capability to provide the service to a level that is acceptable to System Management:

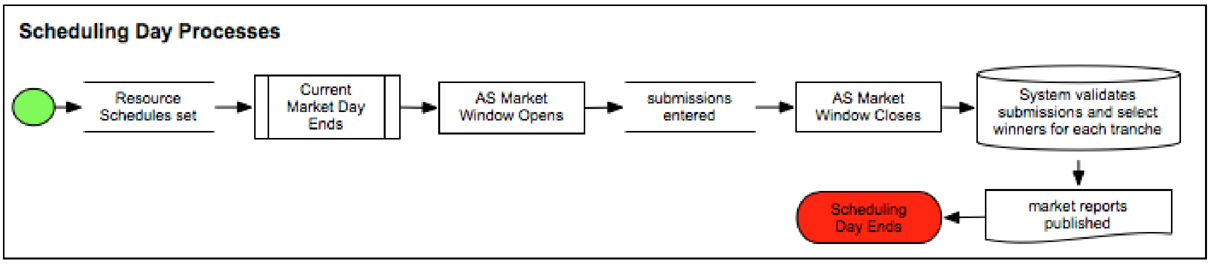
- an Automatic Generation Control ('AGC') system must be installed at the facility;
- The facility's AGC system must be compatible with System Management's AGC system; and
- The facility must be capable to ramp at a rate of 1MW per minute continuously (offers from facilities operating within breakpoints will not be accepted).

The process of applying to enter the LFAS market should include:

- Application by a registered market participant for the admission of a specific facility to the LFAS market;
- A Prequalification process, in which SM coordinates an initial technical assessment to determine whether the generating unit is capable of supplying the LFAS to the required standard;

- An AGC commissioning and testing period in which a facilities interface with SM's AGC systems is commissioned, configured and tested;
- An Agreements period in which the candidate Market Participant reviews and signs a standard set of legal documents which might ensure that it:
  - agrees to ensure its continuous compliance with technical requirements for participation in the LFAS market;
  - is willing to hand operational control to SOCC during those periods where it is successful in winning the right to provide LFAS to SM; and
  - will not engage in behaviour that is intended to reduce the level of competition in the LFAS market either through exercise of market power or collusion with other participants in the market.
- A final approval process in which SM certifies that the new candidate facility has met all requirements for entry to the LFAS market.

3.2 LFAS Scheduling Day processes



SM's believes that the LFAS market would operate most efficiently if the IT systems required to operate the market were integrated with the IMO's existing market systems. This would mean that primary responsibility for the day-to-day operation of the LFAS market would reside with the IMO's Operations Branch.

<u>However, SM has not confirmed that the IMO is in agreement with this approach and so further discussion on organisational responsibility for scheduling day processes is required.</u>

The IMO's market systems validate submissions as they are entered and reject those that do not conform to a predefined set of rules. This ensures that participants whose initial submission is rejected are given the opportunity to make a further conforming submission.

Detailed discussion of submission validation is beyond the scope of this paper. However, there are several aspects of the LFAS design which relate to SOCC operational requirements and systems. Because selection of alternate LFAS providers will be a manual process, it is necessary to limit the granularity at which the LFAS market operates in order to manage the additional complexity that is imposed on Controllers.

Scheduling day processes for the LFAS market should include:

- An extension of the current day to include an additional submissions window for the entry of LFAS offers;

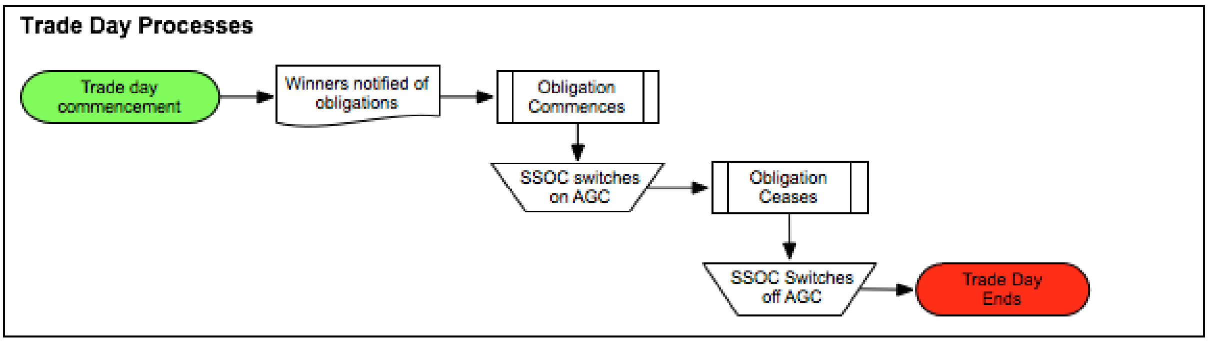
- The timing of this window should be after the closure of the Resource Plan window, this ensures that facility schedules and sync/ desync times are known;
- Offers should only be accepted in relation to facilities which are 'Prequalified' and whose resource schedule indicates that they have sufficient spare capacity to provide the service;
- Offers must relate to a symmetrical quantity block of -/+10MW for a particular facility, and extend over at least 12 trading intervals in a contiguous block (note that a facility with sufficient capacity may be selected to provide both tranches of LFAS);
- At the conclusion of the scheduling day, the IMO should send to the SM details relating to the operation of the LFAS market. Specifically, SM requires knowledge of the facility or facilities that have been selected and the period through which those facilities will be providing the service to SM; and
- If no offers are submitted for a particular period of service, Verve Energy will provide this service in its capacity of the 'provider of last resort' and will be remunerated at MCAP.

Other Considerations

- The WEM's current price caps may not be relevant to the LFAS market. Assuming that there is potential for competition within the market and that information regarding the winning offers is published to the market before the commencement of the next scheduling day, consideration should be given to removing or relaxing price constraints.
- SM believes that the LFAS market should be settled at a single clearing price, rather than a pay as bid price as this allows the provider to offer at its cost rather than trying to discover the shadow price

3.3 LFAS Trade Day processes

Organisational responsibility for Trade Day processes will reside with System Management.



- Full operational control of the load set point of the relevant facility must be passed to System Management in sufficient time for the commencement of LFAS obligations;
- SOCC operators will manually switch to and from the successful participants based on information provided to SM by the IMO at the conclusion of the scheduling day; and

- System Management should be required to remotely dispatch a facility within the base points and upper and lower limits sent by the Market Participant.

3.4 Settlement

Organisational responsibility for conducting settlement processes is likely to reside with the IMO, supported by SM through provision of data.

The Settlement processes should include the following:

- Pro-rating of payments based on the extent to which participants comply with their obligations to the market. For example, in the case where a facility only achieves -8MW to +8MW it should only receive 80% of the payment;
- Implementation of a tolerance (sensitive to the extent of compliance) should allow for any energy impacts of participation in the market at MCAP; and
- Information required to settle the LFAS market should be incorporated within existing process for the provision by SM of data, on a monthly basis to the IMO including:
  - Quantity of conforming Load Following Ancillary Services provided by each participant by Trading Interval; and
  - Dispatch volumes advising Trading Intervals when Load Following Ancillary Services were dispatched and the levels dispatched.
- For Verve Energy, additional information will be required to cover and services provided by Verve under its “Last Resort” obligations eg when no other participants are selected, or when a participant is unable to meet its obligations. This should be settled at MCAP.

Other Considerations

- Implementation of the approach which pro-rates payments may be challenging and would benefit from further discussion at the detailed design stage;

3.5 LFAS Market Administration

Responsibility for the various administrative processes necessary for the operation of the new LFAS market is likely to be shared between the IMO and SM. The responsible organisation would be determined based on whether the process in question was technical or commercial in nature.

Administrative processes that would be necessary for the operation of the LFAS market should include:

- An Audit process to monitor and incentivise ongoing compliance of facilities with the LFAS market technical requirements;
- Power to suspend a participant from the market for a period in response to specified instances of non-compliance such as failure to hand over control;

- Power to revoke a facilities 'Prequalified' status (and therefore its ability to participate in the market) which would only be invoked as a punitive response to repeated serious breaches of the rule requirements which impact negatively on SOCC;
- Directions regarding the publication of market data to promote transparency, competition and to aid participants in making a decision to enter the market; and
- The ability to expand the overall quantity of LFAS exposed to the new market either by releasing new tranches or increasing the capacity of existing tranches.

4. ISSUES RAISED IN CONSULTATION

The following issues are some of those which have been raised in SM's discussion to date.

- That consideration should be given to accepting single sided offers ie that a participant could submit a conforming offer only to provide the 'downside' of the service (SM's view is that this would not be practical given current SSOC systems and the requirement for Controllers to manually manage the selection of providers);
- The entire 60MW requirement should be exposed to the market at its inception (SM's view is that it would be prudent to release additional blocks in a staged manner after consideration of the interest in doing so and of the impact on SSOC);
- Assessment of the implications of the design proposal on cost allocation should be carried out;
- An alternative approach to the reverse auction proposed here would be to not pre-specify the block size and then to select the cheapest set of offers to meet the total requirement (SM's view is that such an approach would need to limit the number of potential suppliers);
- Alternative pricing strategies should not be discounted at this stage (SM agrees but points out the benefit of simplicity and certainty in terms of reducing barriers to entry of the new market);
- More stringent commercial penalties for non-compliance may be more effective than that which is proposed in the paper; and

All issues should be reopened and discussed within the detailed design process should the MAC decide to proceed with the development of an LFAS market based on the concepts outlined in this paper.

5. RECOMMENDATIONS

The Market Advisory Committee is requested to consider the information provided within this paper and to make a decision in relation to the suitability and priority for further development of the concepts provided here.

Agenda Item 9: Strategic Review of Reserve Capacity Mechanism

1. BACKGROUND

At the 10 November 2010 MAC meeting, the MAC requested that the IMO present details of its recent report to the IMO Board on the Reserve Capacity Mechanism. This presentation reviews the performance of the Reserve Capacity Mechanism in particular:

- the quantity and types of capacity procured;
- pricing of capacity;
- the IMO's forecasting performance;
- the performance of the system from a capacity perspective; and
- explores the key issues in the Reserve Capacity Mechanism.

The IMO Board has commissioned a review of the RCM Market Rules and pricing mechanism to identify potential changes to reduce the oversupply of capacity and the cost to the market of this oversupply.

A draft scope of work will be provided to the IMO Board on the 16 December 2010. The IMO expects appointment of a consultant in the first half of 2011.

This presentation is attached as appendix 1 to this paper.

2. RECOMMENDATION

It is recommended that the MAC:

- **Note** the presentation on the performance of the Reserve Capacity Mechanism.

Strategic Review of Reserve Capacity Mechanism for IMO Board

15/12/2010

imowa.com.au

Introduction

- The IMO Board was provided with a strategic report which reviewed the performance of the Reserve Capacity Mechanism. In particular the report:
  - *Analysed the quantity and types of capacity procured;*
  - *Explored the pricing of capacity;*
  - *Analysed the IMO's forecasting performance;*
  - *Looked at the performance of the system from a capacity perspective; and*
  - *Explored key issues in the Reserve Capacity Mechanism.*

Pages 2 Capacity Analysis imowa.com.au

Overview

- The IMO has procured excess capacity in each year. Consequently, the Reserve Capacity Auction has not been required.
- The number of participants providing capacity has grown by more than 150% since market start.
- The number of certified facilities has doubled since market start (52 to 105).
- The diversity of main fuel types (coal and gas) has remained steady with an increase in liquid fuelled plant and DSM in the last two Reserve Capacity cycles.
- Base load capacity grew strongly in 2005 to 2007, building an excess of this capacity but has now stabilised.
- Peaking capacity has grown in 2009 and 2010 Reserve Capacity Cycles but has been used sparingly.
- The Maximum Reserve Capacity Price has increased by 95% over the last four years.
- Facility Outages have reduced since market start.
- The Varanus Island gas explosion in 2008 did not lead to load shedding. However a similar event during summer on a hot day could result in load shedding.

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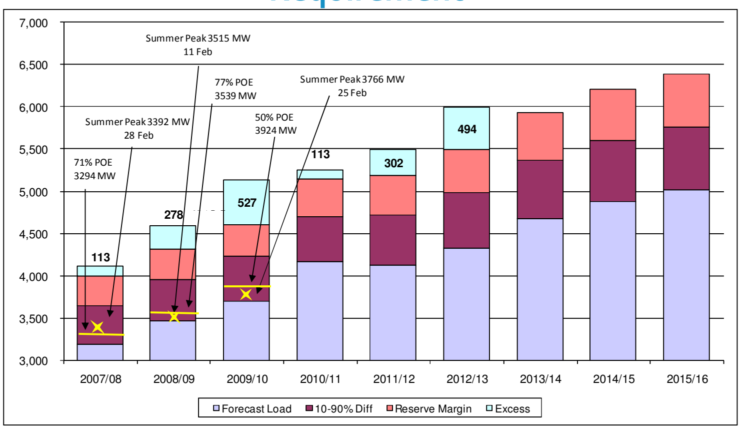
Procured Capacity Compared with Reserve Capacity Requirement



- Level of Capacity had grown by 9.2% per annum since 2005
- Peak demand growth has grown by 5.8% per annum since 2005/06

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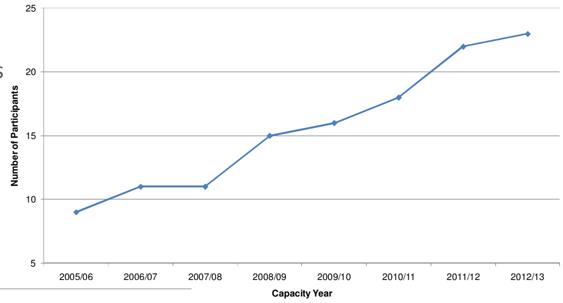
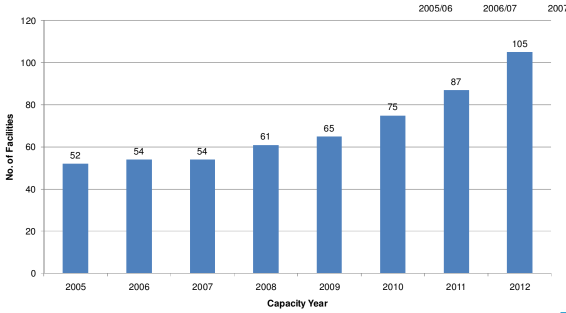
Number of Market Participants and Facilities

- Number of Capacity providers and certified facilities has grown considerably.
- Increasing levels of competition.





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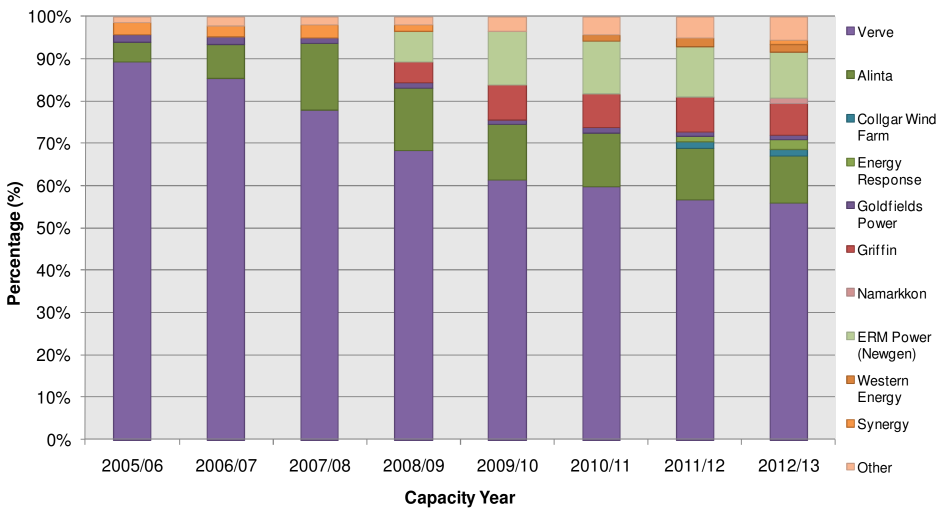
Capacity Credits by Market Participant



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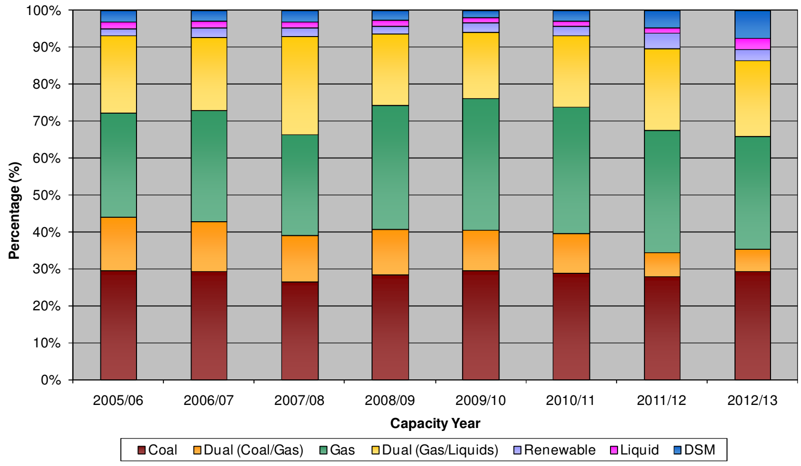
Capacity Credits by Fuel Type



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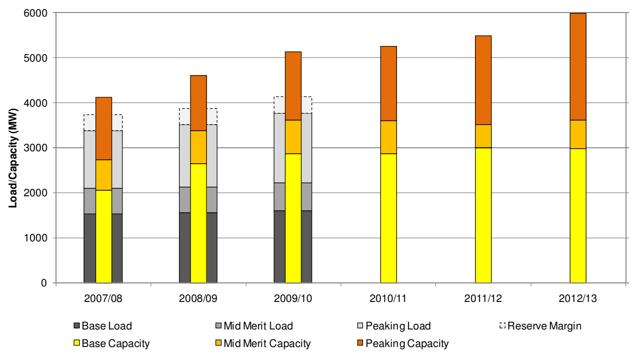
Load Characteristics and Generation Mix in the SWIS



Classification of load (amount of time supplied):
- Base Load- more than 75%
- Mid- Merit- between 25-75%
- Peak Load- less than 25%

- Substantial oversupply of **base load** generation built up in early years of the market
- **Mid merit** generation has largely been unchanged
- **Peaking** Capacity has been less than the peaking load for 2008/09 and 2009/10. With an introduction of large amounts of **DSM** and **peaking** plant will result in double the amount of peaking capacity from 2008/09 to 2012/13.

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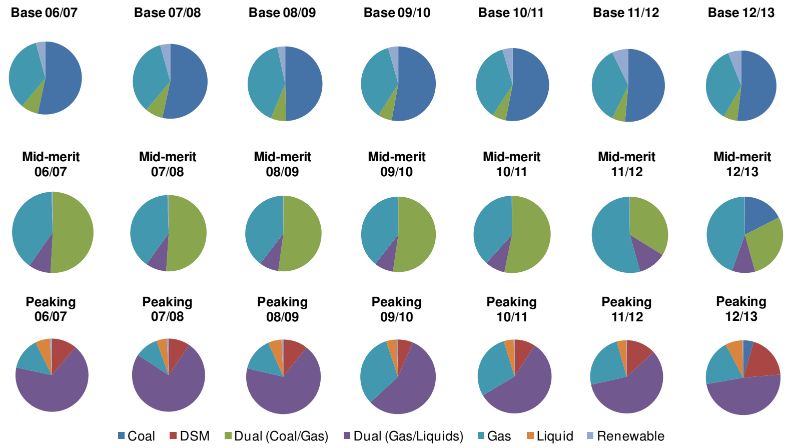
Changes in Fuel Composition



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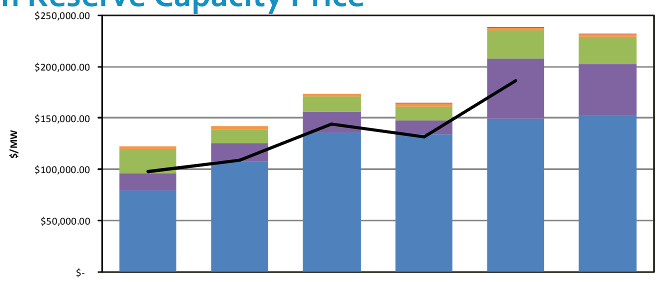
Maximum Reserve Capacity Price



Capacity Year	08/09	09/10	10/11	11/12	12/13	13/14
Power Station Cost	$ 79,110.00	$ 107,404.00	$ 135,701.00	$ 134,091.00	$ 149,306.00	$ 152,465.00
Transmission Costs	$ 16,558.00	$ 18,017.00	$ 20,672.00	$ 13,151.00	$ 58,493.00	$ 49,880.00
Fixed O& M	$ 23,900.00	$ 13,363.36	$ 14,392.09	$ 13,431.00	$ 27,335.00	$ 26,649.00
Fuel Costs	$ 2,907.00	$ 3,456.00	$ 2,631.00	$ 3,151.00	$ 2,615.00	$ 2,713.00
Land Costs	$ -	$ -	$ -	$ 293.00	$ 769.00	$ 785.00
MRCP (nearest $100)	$ 122,500.00	$ 142,200.00	$ 173,400.00	$ 164,100.00	$ 238,500.00	$ 232,500.00
Excess Capacity	6.43%	11.44%	2.19%	5.83%	8.99%	NA
Reserve Capacity Price (per year)	$ 97,836.80	$ 108,458.57	$ 144,235.38	$ 131,804.58	$ 186,001.04	NA

- The early growth in MRCP was largely driven by increases in construction and labour costs.
- The substantial price rise for 2012/13 was attributable to a significant increase in transmission costs and the inclusion of Use of System charges in the transmission fixed O&M costs.

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Forecasting Accuracy

Year	Peak Demand (MW)	PoE of peak day	Temperature- adjusted forecast (MW)	Year of Forecast	Difference (MW)	Forecast Accuracy
2007/08	3392	71 %	3294	2005	-98	-2.9%
2008/09	3515	77%	3539	2006	+24	0.7%
2009/10	3766	50%	3924	2007	+158	4.2%

- Generally significant economic changes have occurred after the time when forecasts were prepared.
- The strong economic boom from 2006-2008 was not well understood in 2005, explaining the lower forecast in 2007/08.
- The GFC was not predicted in 2007, explaining the higher forecast in 2009/10 summer.

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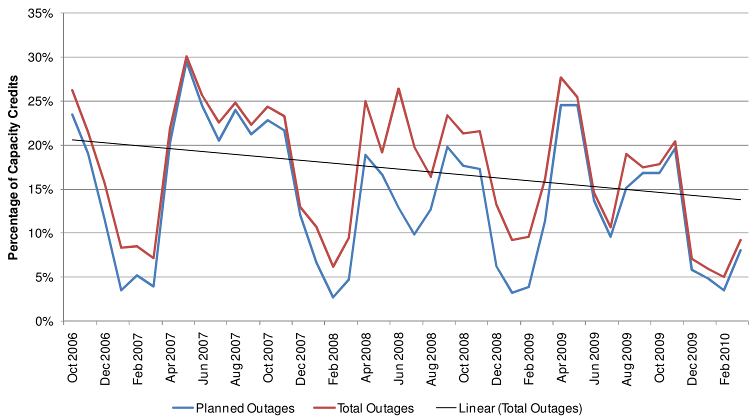
Facility Outages



- Downward trend on Facility outage rates, which is good for system reliability

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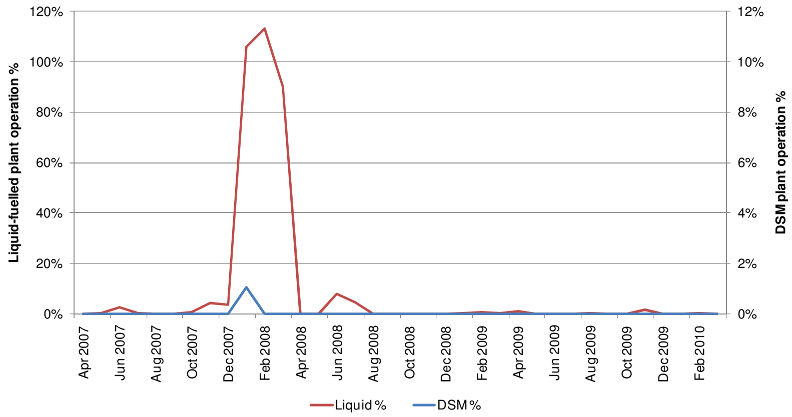
Supply Contingencies



- Utilisation of liquid-fuelled capacity has been very low except for 2007/08 Summer.
- DSM was utilised in 2007/2008 summer due to anticipated supply shortfalls. This is the only occasion where DSM has been utilised to date.

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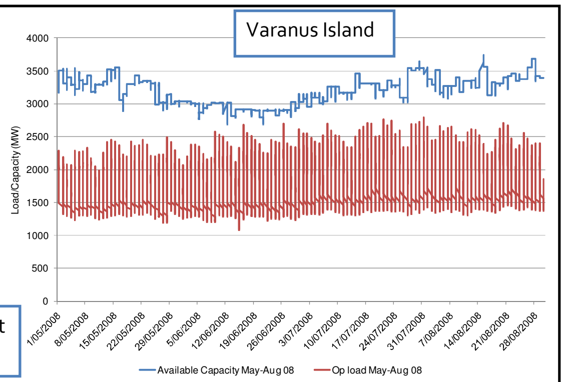
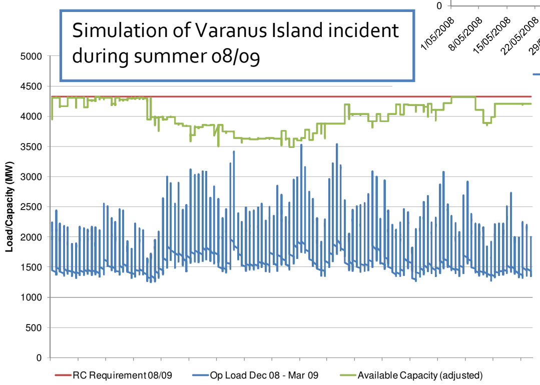
Effect of Fuel Shortage

Confirmation that spare capacity was available during the period of gas shortage





At no time operational load exceeds available capacity- involuntary load shedding not required

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Review of the Reserve Capacity Mechanism

- The Review of the RCM was identified as the second highest priority item in the Market Rules Evolution Plan. This review is scheduled to commence in the second quarter of 2011.Some of the issues that would need to be explored in this review are:
  - *the Reserve Capacity Auction, a key element in the design of the RCM that has not yet been required;*
  - *the Availability Classes, which provide no differentiation between base and peaking generation;*
  - *the automatic assignment of Capacity Credits to all Certified Reserve Capacity that declares the intent to bilaterally trade, irrespective of the surplus that may result;*
  - *the higher costs that must be paid by the market in the event of surplus capacity, despite the current price scaling mechanism; and*
  - *the value of the Expressions of Interest process, as flagged by Market Participants.*

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Other Reviews

- **The Renewable Energy Working Group**
- **Maximum Reserve Capacity Working Group**
- **Curtailable Loads**
- **Dual-fuel**
- **Reserve Capacity Refunds (MEP)**
- **Reliability criteria and process of forecasting SWIS peak demand**

In addition to the reviews above, Western Power has indicated its support for a review of the benefits of a transition from an unconstrained to a constrained network. Such a change would pose implementation challenges for the RCM.

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Agenda Item 10: 2010 Year in Review

What	2008	2009	2010
MAC and Working Group meetings	**22**	**20**	**38**
MAC meetings	7	9	9
MAC Special Meetings	0	0	3
Renewable Energy Generation Working Group	3	5	9
Rules Development Implementation Working Group	n/a	n/a	7
Maximum Reserve Capacity Price Working Group	n/a	n/a	5
IMO Procedures Working Group	1	2	3
System Management Procedures Working Group	3	3	2
Reserve Capacity Refund Working Group (2008)	1	1	n/a
Supplementary Reserve Capacity Working Group	6	n/a	n/a
Energy Price Limits Working Group	1	n/a	n/a
Rule Changes Developed/Underway	**40**	**40**	**37**
Procedure Changes	**0**	**19**	**12**
Stakeholder Workshops (i.e. Rule Changes, Procedure Changes, Market Design review and NCS workshops)	**9**	**7**	**6**
RulesWatch issued	**n/a**	**6**	**49**

Year	Significant Rule Changes
2008	Funding of SRC (RC_2008_27) Funding of SRC in the Event of Capacity Credit Cancellation (RC_2008_34) Capacity Refund Mechanism – New Generators (RC_2008_35)
2009	Updates to Commissioning Provisions (RC_2009_08) Early Certified Reserve Capacity/Changing the Window of Entry (RC_2009_10 & 11) MAC Constitution and Operating Practices (RC_2009_28)
2010	Calculation of Net STEM Shortfall (RC_2010_03) Required Level and Reserve Capacity Security (RC_2010_12) Certification of Reserve Capacity (RC_2010_14)

Year	Significant Rule Changes
	Calculation of Capacity Value for Intermittent Generation (RC_2010_25 & 37) Ancillary Services payment Equations (RC_2010_27) Curtailable Loads and Demand Side Programmes (RC_2010_29)