Independent Market Operator

Market Advisory Committee

Agenda

Meeting No.	37
Location:	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Wednesday 13 April 2011
Time:	2.00 – 5.00pm

Item	Subject	Responsible	Time
1.	**WELCOME**	**Chair**	5 min
2.	**MEETING APOLOGIES / ATTENDANCE**	**Chair**	5 min
3.	**MINUTES OF PREVIOUS MEETING**	**Chair**	10 min
4.	**ACTIONS ARISING**	**Chair**	10 min
5.	**MARKET RULES**		
	a) Market Rule Change Overview	**IMO**	5 min
6.	**MARKET PROCEDURES**		
	a) Overview	**IMO**	5 min
7.	**WORKING GROUPS**		
	a) Overview and membership updates	**IMO**	5 min
	b) MRCPWG Update	**IMO**	10 min
8.	**MEP: RESERVE CAPACITY REFUNDS (UPDATE)**	**IMO**	30 min
9.	**MEP: BALANCING AND LOAD FOLLOWING ANCILLARY SERVICES MARKETS**	**IMO**	30 min
10.	**GENERAL BUSINESS**		
11.	**NEXT MEETING: 11 May 2011 (2.00 – 5.00pm)**		

Independent Market Operator

Market Advisory Committee

Minutes

Meeting No.	36
Location	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date	Wednesday 9 March 2011
Time	Commencing at 2.00 pm

Attendees	**Class**	**Comment**
Allan Dawson	Chair	
Troy Forward	Compulsory – IMO	
Stephen MacLean	Compulsory – Customer	
Ken Brown	Compulsory – System Management	
Andrew Everett	Compulsory – Generator	
Peter Mattner	Compulsory – Network Operator	
Steve Gould	Discretionary – Customer	
Corey Dykstra	Discretionary – Customer	
Michael Zammit	Discretionary – Customer	
Peter Huxtable	Discretionary – Contestable Customer Representative	
Andrew Sutherland	Discretionary – Generator	
Shane Cremin	Discretionary – Generator	
Ben Tan	Discretionary – Generator	
Chris Brown	Observer – ERA	
Paul Biggs	Small Use Customer Representative	
Apologies	**Class**	**Comment**
Nerea Ugarte	Minister's appointee	
Also in attendance	**From**	**Comment**
Jenny Laidlaw	IMO	Minutes
Pablo Campillos	EnerNOC	Observer
Wana Yang	ERA	Observer
Jacinda Papps	IMO	Observer
Fiona Edmonds	IMO	Observer
Courtney Roberts	IMO	Observer

Item	Subject	Action
1.	**WELCOME** The Chair opened the meeting at 2.00 pm and welcomed members to the 36th meeting of the Market Advisory Committee (MAC). The Chair welcomed new members Mr Ben Tan and Mr Michael Zammit to the MAC, and congratulated Mr Corey Dykstra, Mr Shane Cremin and Mr Peter Huxtable on their reappointments. The Chair reminded members that they had been appointed as representatives of a participant class rather than the specific entities for which they worked. MAC members were obliged, under the MAC Constitution, to act in the best interests of the market.	
2.	**MEETING APOLOGIES / ATTENDANCE** Mr Paul Biggs offered an apology for Ms Nerea Ugarte. The following other attendees were noted: • Pablo Campillos (Observer) • Jacinda Papps (Observer) • Courtney Roberts (Observer) • Wana Yang (Observer) • Fiona Edmonds (Observer)	
3.	**MINUTES OF PREVIOUS MEETING** The minutes of MAC Meeting No. 35, held on 9 February 2011, were circulated prior to the meeting. The Chair noted that Mr Andrew Everett and Mr Dykstra had sent emails to MAC members clarifying statements they had made during the meeting. The following amendments were agreed. ***Page 6: Section 4a: Worked example of dispatch of a peaker versus DSM (Action Point 121)*** • “Mr Zammit noted that it would be incorrect to assume the marginal cost for all DSPs to reduce consumption would all be the same. Mr Dykstra noted <u>that it would be reasonable to assume </u>that a peaker has a high capital cost and a lower …” ***Page 11: Section 6c: De-registration of Rule Participants who no longer meet registration requirements [PRC_2010_31]*** • “Mrs Papps submitted that if the Rule Participant does not apply for de-registration and pay the de-registration fees then the IMO is faced with the costly and time-consuming process of going to the ERB to de-register the Rule Participant. The IMO considers that it should be able to de-register a Rule Participant in ~~these circumstances~~ <u>the circumstances listed in the paper </u>without the need to apply to the ERB. Mrs Papps noted that the Pre Rule Change Discussion Paper PRC_2010_31 outlines a proposed process which allows the IMO to do so.”	

Item	Subject	Action
	• "The Chair noted that this situation has already occurred in the market. The IMO had issued cure notices to a company in liquidation, which did not wish to remain a Market Participant but was unable to pay the required de-registration fee. Mr Dykstra queried whether the fees were cost-reflective. Mrs Papps confirmed that this was the case. Mr Dykstra suggested incorporating these fees with registration fees. ~~considered that de-registration fees were not cost-reflective and suggested removing them.~~ Mrs Papps responded that this would not remove the problem completely as the IMO would still need to initiate the de-registration process in some cases." • "Mr Dykstra queried whether it really mattered if these Rule Participants were not de-registered. Mr Dykstra noted that a significant amount of paperwork was involved in the registration of a Rule Participant, and suggested that it could be ~~useful to leave~~ valuable to an inactive Rule Participant to keep the option to retain its registration status." ***Page 15: Section 8c: RDIWG Update*** • "Mr Dykstra queried when the ~~pricing~~ scenarios being developed by the IMO would be distributed to RDIWG members. The Chair replied that these would be circulated as soon as possible, and that the Market Evolution Program team had been reminded of the urgency of the work. Mr Forward noted that one scenario had been reviewed with System Management the previous day." ***Page 16: Section 9a: Operational workload and the Market Evolution Program*** • "Mr Dykstra considered that the IMO was not obliged to progress all of the proposals submitted to it. Mr Forward asked if MAC members wished the IMO to exercise this option more frequently. The Chair considered that the IMO was never too busy to progress a proposal. Mr Andrew Everett ~~agreed that a resources shortage was not a valid reason to not progress a proposal~~considered each participant should determine their level of engagement and resource appropriately. Mr Campillos queried whether Mr Dykstra was suggesting an increase in the combination of related changes into Rule Change Proposals. Mr Dykstra replied that he was unhappy with the current threshold for the acceptance of Rule Change Proposals by the IMO, considering that ~~it should be stronger~~the burden of proof should be higher. Mr Dykstra considered that some recent proposals should not have been accepted by the IMO and that more work should have been done upfront." Subject to the agreed amendments, the MAC endorsed the minutes as a true and accurate record of the meeting. *Action Point: The IMO to amend the minutes of Meeting No. 35 to reflect*	**IMO**

Item	Subject	Action
	the points raised by the MAC and publish on the website as final.	
4.	**ACTIONS ARISING** The actions arising were either complete or on the meeting agenda. The following exceptions were noted: • **Item 88/89:** Mr Troy Forward suggested that Items 88 and 89 be removed from the list of MAC Action Points, on the understanding that the Office of Energy will distribute the report when it is ready. Mr Biggs agreed to Mr Forward's suggestion, and advised that the report should be ready for circulation in the next few weeks. *Action Point: The IMO to remove Items 88 and 89 from the list of MAC action points.* • **Item 119:** To be undertaken in March 2011. • **Item 130:** Mr Forward considered that new load information was often considered to be sensitive and participants had raised issues in the past about specific load information published by the IMO. Given the speculative nature of the information the IMO proposed to not separately identify large new loads, although it will continue to publish forecast new loads as an aggregated block. Mr Stephen MacLean questioned whether the IMO was happy that it had enough information on new loads, suggesting that MAC members would be able to provide additional information if asked. Mr Forward responded that it was normal practice for the IMO to meet with representatives from companies developing new loads as part of its due diligence. Mr MacLean noted that Synergy was keen to talk to the IMO about expected new large loads. Mr Forward noted that he had recently met with Mr Simon Middleton from Synergy. • **Item 167:** Mr Forward noted that this action point was now complete. Mr MacLean noted that the study dated back to 2003, suggesting that a study of this nature should be undertaken every few years. Mr Ken Brown agreed with Mr MacLean, noting that system inertia was changing over time. • **Item 12 (2011):** Underway. • **Item 14:** Mr Forward noted that after considering the comments of MAC members the IMO suggests the removal of the proposed changes to the Relevant Demand calculation from the Rule Change Proposal: Curtailable Loads and Demand Side Programmes (RC_2010_29). The Relevant Demand calculation options were worthy of investigation at a more detailed level, which would probably involve an industry forum given the level of interest in the issue. Mr Forward proposed that RC_2010_29 should continue to progress without the Relevant Demand components.	**IMO**

Item	Subject	Action
	There was some discussion about whether a Relevant Demand workshop could be tied to the proposed review of the recent Varanus Island incident and its impact on the Wholesale Electricity Market (WEM). Mr Zammit considered that it would be preferable to keep these workshops separate, as they would have slightly different audiences. Mr Zammit suggested that in order to compare Relevant Demand options it will be necessary to go into a great level of detail about potential impacts. The Chair suggested that the initial workshop should focus on the Varanus Island events, and that the lessons learnt from these events should be used as an input to the development of any Relevant Demand workshops. Mr Dykstra stated that he had hoped the outcomes of the Varanus Island incident would feed into the IMO's review of the Reserve Capacity Mechanism (RCM), providing a good example of what worked and what did not work. Mr Dykstra noted that Alinta had expressed in its submission on RC_2010_29 a preference to delay the progress of the Rule Change Proposal until the outcomes of the RCM review are known. Mr Forward noted Alinta's submission but stated that the IMO preferred not to wait to progress RC_2010_29. In response to a query from Mr MacLean, the Chair advised that the Draft Rule Change Report for RC_2010_29 was now due to be published on 18 March 2010.	
5a	**MARKET RULE CHANGE OVERVIEW** The MAC noted the Market Rule Change Overview. The Chair noted that extensive analysis had been undertaken in relation to the Renewable Energy Generation Working Group (REGWG) Work Package 3 Pre Rule Change Discussion Paper: Ancillary Services Payment Equations (PRC_2010_27) and the Rule Change Proposal: Cost_LR (RC_2010_33). During this analysis the IMO identified some cases of vague and inconsistent use of units (MW versus MWh) in the Market Rules, and as a result has found the need to change some of the inputs into the settlement equations. This should have been mentioned in the Draft Rule Change Report for RC_2010_33. As a result the IMO will be required to make some amendments to its settlements system.	
5b	**ANCILLARY SERVICES PAYMENT EQUATIONS [PRC_2010_27]** Mr Forward noted that the Pre Rule Change Discussion Paper: Ancillary Services Payment Equations (PRC_2010_27) originated from the outworkings of REGWG Work Package 3: Frequency Control Services. The paper was first presented to the MAC at its November 2010 meeting, where the IMO undertook to complete the development of the Pre Rule Change Proposal. Mr Forward noted that the cover paper for PRC_2010_27 outlines the approach the IMO has taken to a number of issues, including issues raised in the original Pre Rule Change Discussion Paper and issues raised following internal IMO review and discussions with external stakeholders. The updated paper has been brought back to the MAC for	

Item	Subject	Action
	discussion about the next steps to be taken. Mr MacLean noted that the paper was still a Pre Rule Change Discussion Paper. Mr MacLean supported the decision to commission an independent technical review of the drafting. Mr Everett and the Chair agreed that the proposal had become very complex. Mr Dykstra queried the linkages between this proposal and the Rules Development Implementation Working Group (RDIWG) proposals relating to balancing. Mr Forward considered that while the RDIWG proposals around a competitive market for balancing and Ancillary Services may affect the availability cost calculation aspect of the proposal, they did not affect the Load Following cost allocation component. Mr Dykstra stated that his question related to the cost calculation aspect of the proposal, noting that the paper was proposing new availability cost calculations while the IMO was also working on a market mechanism for Load Following Ancillary Services. Mr Dykstra questioned why changes to the availability cost calculations should be made now if a market concept is due to be developed within a couple of months. Mr Forward reiterated that the IMO had undertaken to finish the task that had been started, but agreed that it could be appropriate to move this work across to the Market Evolution Program (MEP). Mr Forward noted that the MEP had only recently taken on responsibility for work on the development of a competitive market for Load Following Ancillary Services (LFAS). Mr Dykstra considered that the proposal appeared to be more complicated in terms of the proposed availability cost calculations than the original ROAM Consulting proposal. Mr Forward responded that while the cost calculation principles were unchanged from ROAM's original proposal, further detail had been added to the paper to fill in some of the gaps in the original drafting. Mr Cremin considered that greater efforts should be made to reduce Load Following requirements and costs before focussing on changes to cost allocation. Mr Cremin noted changes made to the technical requirements for wind farms in the National Electricity Market, to reduce the quantity of Ancillary Services required. Mr Cremin considered that the proposed allocation process sends the wrong messages, as it does not encourage individual Intermittent Generators to reduce the Load Following requirements of their facilities. Mr Cremin submitted that there was a general acceptance that Intermittent Generators were inherently inefficient, and that the "smearing" of Ancillary Services costs was in line with the principle underlying the use of Renewable Energy Certificates (RECs). Mr Cremin submitted that in any case these costs would eventually be allocated to Loads. The Chair questioned whether members had a problem with the cost calculation changes or the cost allocation changes. Mr Cremin reiterated that he considered the allocation methodology to be bad, as it did not give any incentive to an Intermittent Generator to reduce its Load Following requirement. Mr Dykstra considered that given the current MEP	

Item	Subject	Action
	balancing proposal the proposed cost calculation changes were premature, particularly if the current equations will remain workable in the short term. Mr Dykstra also considered that the allocation issue needed to be discussed further, suggesting that participants would not respond to the proposed "pricing signals" due to the requirement to meet renewable energy targets. Mr Dykstra stated that the Minister had not provided guidance but he would expect Synergy will want to obtain its RECs locally. Mr MacLean noted that Synergy's concern was that the market does not have a position as yet. Mr MacLean agreed that Mr Cremin had a point about how the market should give the right signals to investors in renewable generation, and did not think that the REGWG had had time to consider this properly. Mr Forward responded that there was no argument about the need to develop an appropriate approach, and that PRC_2010_27 was back on the table to allow consideration of other recent developments. Mr Dykstra noted that the two components of the proposal (cost calculation and cost allocation) could be progressed separately, and agreed with Mr Cremin that the costs of Intermittent Generators will be indirectly borne by Loads. Mr Dykstra submitted that the economic efficiency of the market would not be affected by changing this allocation of costs. The Chair responded that the change would send more appropriate signals to investors. Mr Dykstra responded that these costs would be passed through to Loads in an efficient market, and so questioned why the market should bother with the changes. The Chair and Mr Everett responded that Loads may choose not to meet their renewable targets by contracting Intermittent Generation in Western Australia. There was some discussion about whether Market Customers would seek to obtain their RECs from within Western Australia. Mr Ken Brown noted that several jurisdictions around the world were working on how to handle the impact of wind generation. Mr Dykstra suggested that some of the issues relating to wind generators should be included in the IMO's review of the RCM. Mr Brown noted the ongoing improvements to wind farm technologies and the trend towards the tightening of requirements for wind farms in technical rules. The Chair considered that the proposal reflected the basic principle of "causer pays". Mr Everett noted the original aim of the proposal was to correct problems with the cost calculation formulas and to implement the causer pays principle. Mr Everett considered that the proposal had become complicated and there was a question of what it would cost, but suggested that if this cost was acceptable then the IMO should progress the proposal. Mr Forward noted the issues that had been raised about the source and time-granularity of some of the parameters used in the PRC_2010_27	

Item	Subject	Action
	calculations. Mr Forward considered that a trade-off existed between accuracy and cost/complexity, and that while the appropriate balance could be debated the immediate question was whether or not to progress PRC_2010_27. Mr Everett queried the decision by the IMO not to include Verve Energy's suggested amendments to the cost allocation calculations to cater for solar facilities. Mr Forward responded that the lack of solar facilities in the WEM and the lack of available information on solar facility fluctuations had led to the IMO's decision. Mr Everett suggested that the amendments did not require a great deal of effort and so could easily be included now. Mr Dykstra noted that Alinta, in its submission to the ERA on the 2010 Review of Margin_Peak and Margin_Off-Peak, had raised its concerns about the "black box process" used to determine the margin values, suggesting that it should be possible to assess how accurate the models are at predicting costs. Mr Dykstra considered that the proposed cost calculations were based on the same basic approach as the current calculations, and so before embedding these basic availability cost concepts further he would want an idea of how well these concepts were working. Mr Forward asked whether the proposal should be progressed given the status of the MEP work on balancing and Ancillary Services. The Chair considered that there was an obligation to send clear signals to potential investors in Intermittent Generators, so that they are aware of the costs coming their way. Mr Andrew Sutherland queried how a developer would be able to determine what these costs would be. Mr Cremin reiterated his view that the proposal would only shift costs to Intermittent Generators and then back to Loads. The Chair considered that this would not necessarily be the case. There was some discussion about the financial impact of the proposed changes on Intermittent Generators and whether Market Customers would accept the pass through of Load Following costs from generators or seek to obtain their RECs through other sources. Mr Dykstra raised the problem for current Intermittent Generators with existing bilateral contracts, who might be unable to pass through any new Ancillary Services costs to their customers. The Chair noted that the IMO Board had started to look at options for the deferral of rule changes that impose these costs, and had requested examples of such deferrals from the National Electricity Market (NEM). The Chair considered there was a need to decide how to send the correct signals to new investors and also deal with those that have made decisions in the past. There was further discussion about how the overall Load Following requirement might be reduced through changes to the technical rules applying to wind farms. Mr Brown noted that while there are ways to limit Ancillary Services requirements by limiting wind generation, these approaches could affect the financial viability of these generators. Mr MacLean considered that a price exceeding -$40 may be required to	

Item	Subject	Action
	encourage wind farms to reduce output, as there were other issues to be considered apart from compensation for lost RECs. Mr Ben Tan suggested that a proposal to send signals only to new Intermittent Generators raised issues of regulatory risk. Mr Forward responded that continuing to do nothing about the issues also imposed a regulatory risk. Mr Paul Biggs raised a concern about the impact of the proposal on the other (non-wind) types of renewable generation. Mr Forward considered that the first step should be to address the current issue (wind generation), while the next step would be to look at differentiation of treatment for the various types of renewables. Mr MacLean considered that there was an immediate problem to be addressed as a variety of renewable generators already existed. Mr Forward noted the complexity of introducing additional Facility classes into the Market Rules. The Chair expressed support for the suggestion made by Mr Cremin to include incentives for Intermittent Generators to reduce their Load Following requirements. Mr Dykstra considered that in relation to cost allocation, it was desirable to send the right signals going forward. Mr Forward noted that the proposal assumed common treatment of both new and existing generators. Mr Dykstra considered that the benefits outlined in the proposal related to new investments. The Chair replied that investments in existing plant to reduce the cost impact were also encouraged. There was further discussion about the financial impact of the proposal. Mr Sutherland considered that currently there is no information available to allow generators to adjust their activities, submitting that there was no way for a generator to tell if its Ancillary Services bills were wrong or right. The Chair noted his long standing concerns about the settlement systems not making timely information available to participants. Mr Cremin noted that Griffin Energy had been working on analysing its statements, and that it was very difficult to understand the reason for large changes in costs between one Trading Interval and the next. The Chair considered that the MEP aimed to make more information available to participants, and noted that he was keen to better understand Mr Cremin's issue around variations in Ancillary Service costs between Trading Intervals. The Chair asked MAC members for their thoughts on the next steps for PRC_2010_27. Mr Everett suggested that the proposal be formally submitted as a Rule Change Proposal, to allow for a formal submissions process. Mr MacLean queried when the technical review of the calculations would occur, but noted that a technical review should not hold up the progress of the proposal. There was some discussion about the IMO Board's ideas about the deferral of rule changes. Mr Dykstra considered that the proposal was significantly more complex than originally expected. As the proposal extended a concept for cost calculation that already existed, data for a few years was available to allow a check of the robustness of the general approach. Mr Dykstra	

Item	Subject	Action
	considered that the current equations were workable in the short term and that the MEP balancing proposal should expect to change how unit costs are allocated here. Mr Dykstra suggested that the MEP work and a review of the current methodology should be undertaken first, and that the cost calculation changes should only be progressed if the MEP proposals come to nothing. Mr Dykstra considered that there did not appear to be any benefit with proceeding with these changes now, noting that ROAM Consulting had also recommended the introduction of a competitive Ancillary Services market. Mr Forward noted that as System Management had undertaken to develop a proposal for a competitive Ancillary Services market the REGWG had not pursued the recommendation further. Mr Ken Brown stated that he did not want people to think that there will be a plethora of Ancillary Service providers available after the implementation of the MEP proposals, noting the dependency on Open Cycle Gas Turbine (OCGT) generators for Frequency Keeping.	
5c	**REASSESSMENT OF ALLOWABLE REVENUE DURING A REVIEW PERIOD [PRC_2011_02]** Mr Chris Brown provided an overview of the ERA's Pre Rule Discussion Paper: Reassessment of Allowable Revenue during a Review Period (PRC_2011_02). Mr Brown noted that while the IMO's budget for the MEP was in the order of $7 million, under the current Market Rules the ERA had not been required to review the proposed expenditure. This triggered a concern (shared by both the ERA and the IMO) that such a large amount of expenditure could be exempt from review, leading to the development of PRC_2011_02. The Chair advised that when the IMO went to the ERA to seek approval for a Declared Market Project the ERA had advised that this was not in its jurisdiction. The IMO, however, has still provided the ERA with all the information it would normally provide for such a review. The IMO supports the proposal as it provides both the market and the Minister with protection from the IMO or System Management embarking on major projects without review. Mr Brown considered that issues 2 and 3 in PRC_2011_02 were closely related. Mr Brown noted that in PRC_2011_02 the ERA proposed a reduction in the threshold level for the triggering of a review from 15 percent of Allowable Revenue in a Review Period to 10 percent. However, Mr Brown noted that this was based on a "gut feeling" and that the ERA wished to discuss the appropriate threshold level with MAC members. With regard to issue 3, Mr Brown noted that if the IMO or System Management exceeded their budget without ERA review and approval they were taking a risk in that the ERA might reject the additional expenditure in a future period. The ERA has proposed new rules allowing the IMO or System Management to ask the ERA for an assessment regardless of whether the expenditure threshold has been reached. This would provide in effect a pre-determination, giving certainty that the	

Item	Subject	Action
	expenditure would not be rejected in future. Mr Brown noted that as the monetary amounts involved may be small, the ERA has sought discretion on whether to publicly consult on a review or not. In response to a query from the Chair, it was clarified that the IMO or System Management would be able to obtain pre-approval for expenditure, similar to that provided through New Facilities Investment Test (NFIT) decisions. Mr Dykstra noted that regardless of where the threshold was set, there would always be situations where the proposed expenditure fell under the threshold, and that the proposal would give the IMO and System Management the ability to gain approval for this expenditure early. Mr Huxtable queried whether there would be a minimum level of expenditure applicable to these requests. Mr Brown responded that while there was not a fixed minimum the ERA has reserved the right not to make a determination in these situations. Mr Forward considered that as the IMO and System Management would be unlikely to make a submission lightly it could be reasonable for the ERA to be obliged to make a determination. Mr Peter Mattner noted that the NFIT has a threshold, above which the ERA must make a determination and below which the ERA may make a determination. Mr Mattner noted that a determination was defined as a decision to approve or not approve a proposal, which could result in uncertainty where a proposal was not approved but where a proposal for a lesser amount may have been approved. After some discussion it was clarified that the ERA would still be required to make a determination on proposals over the 10 percent threshold. Mr Ken Brown questioned what would have happened if the ERA had rejected the IMO's proposed expenditure for the MEP. The Chair replied that if this had eventuated then the IMO would have notified the Minister and stopped the project. Mr Pablo Campillos queried whether the 10 percent threshold might prove restrictive for the IMO and System Management in future. Mr Mattner queried whether any time limit had been set for the ERA's determinations, considering that it could pose a risk to the IMO if no time limit existed. Mr MacLean noted that there was also an ERA resourcing issue to be considered. The Chair considered that there could be a problem if the market wants the IMO to progress a project quickly but the ERA was to take 3-6 months or more to make a determination. Mr Chris Brown replied that the ERA would look into this issue. Mr MacLean noted that situations might arise where both the IMO and System Management were making multiple submissions at the same time.	
6a	**MARKET PROCEDURE CHANGE OVERVIEW** Mr Dykstra queried comments made by the IMO about the Prudential Requirements Procedure Change Proposal in the overview of recent and upcoming procedure changes distributed for the meeting. The Chair	

Item	Subject	Action
	noted that there were issues relating to the current rules around to Prudential Requirements and the IMO was undertaking a detailed process review with a view to making further changes to the Market Rules. Mr Dykstra noted the comments made by Alinta in its submission on the Rule Change Proposal: Acceptable Credit Criteria (RC_2010_36), around the potential exposure of Market Participants to Civil Penalties if the IMO removes a credit provider from the Acceptable Credit Criteria list without prior notice. Mr Dykstra noted that if the Rule Change Proposal: Reserve Capacity Security (RC_2010_12) progresses then Market Participants could be required to find an alternative credit support source for both Credit Support and Reserve Capacity Security (RCS) within one business day, or else face Civil Penalties. Mr Dykstra considered that it could be particularly difficult for a Market Participant to replace RCS in this timeframe if its Facilities are not currently generating any cash flow. Mr Forward replied that the IMO needed to balance these difficulties against the risk of leaving the market exposed. The Chair noted that in the past the IMO had usually provided more than the official 24 hours notice of impending changes to participants' credit support requirements. The IMO noted the overview of recent and upcoming procedure changes.	
7a	**WORKING GROUP OVERVIEW** The MAC noted the Working Group overview.	
7b	**MRCPWG UPDATE** In response to a query from Mr Dykstra, it was confirmed that the date of the next MRCPWG meeting was 24 March 2011, not 24 February 2011 as listed in the overview document. The MAC noted the MRCPWG update.	
7c	**RDIWG UPDATE** Mr Forward repeated his offer from previous meetings to provide a one on one progress update on the work of the RDIWG to any member on request. The MAC noted the RDIWG update.	
8	**MAC ANNUAL REVIEW WASH UP** The Chair noted that an overview paper and the 2011 MAC Composition Review Report had been distributed to MAC members with the papers for this meeting. The Chair considered that the record of attendance for MAC meetings in the previous year had been exemplary.	
9	**GENERAL BUSINESS** ***RCM Review***	

Item	Subject	Action
	Mr Forward noted that the IMO had appointed The Lantau Group to conduct the RCM Review. The Lantau Group was in the process of contacting participants to arrange meetings with them, having decided to take the approach of talking with participants on a one on one basis to encourage more open discussion. Mr Forward considered that these discussions would provide participants with an opportunity to contribute to the RCM Review, and urged MAC members to raise any issues that they had with the RCM in these meetings. The Chair confirmed that the IMO wanted to hear the views and concerns of industry so that they could be incorporated into the report to the IMO Board. ***Varanus Island Issue - Workshop*** There was some discussion about the proposed briefing on the recent Varanus Island events and their impact on the WEM. Mr MacLean noted that Mr Jim Brosnan from Simcoa had some views to contribute to this briefing. Mr Cremin raised his concerns about the structure of Spinning Reserve costs, noting that he had discussed the issue with Mr Phil Kelloway. Mr Cremin stated that during the recent Varanus Island incident there were periods during which Griffin Energy was instructed to increase its output as much as possible. Griffin Energy had complied with these requests, but as a result had incurred very large Spinning Reserve charges through having the only large units operating in some Trading Intervals. Mr Cremin suggested that perhaps some simple changes could be applied to address this problem. The Chair suggested that after the RDIWG had reached agreement on the design principles for balancing the IMO could start collecting some data on this issue, perhaps targeting a May/June 2011 timeframe. Mr Ken Brown noted that if System Management asks a Facility to generate beyond its normal limits then there is an inherent risk that this could force the Facility to trip and there was a need to consider the associated financial penalties. Mr Zammit considered that it was a good time to conduct a review as recent events have provided some useful data for analysis. The Chair agreed that there was a great deal to be learned by studying exceptions to normal operations. Mr Cremin agreed that the Varanus Island incident was a good example of a rare event, but was concerned more generally about the severe financial impacts of Ancillary Service costs on Griffin Energy's Facilities. The Chair considered that there was a need to provide better information to Market Participants so that they could better understand the impact of their actions. There was some discussion about whether it was appropriate to penalise participants for actions that they could not change. Mr Ken Brown considered that the Varanus Island incident showed that the WEM was a fuel dominated market, noting that that System Management had had to shift from the Dispatch Merit Order due to the	

Item	Subject	Action
	emergency. There was further discussion about the flow of information during the incident and the dependency of the WEM on the Dampier to Bunbury Natural Gas Pipeline (DBNGP). Mr Biggs noted that the Office of Energy would be undertaking a wash up of the event by early April, and so any market feedback would be useful to have. Mr Biggs noted the incident was successfully managed through the market. Mr Ken Brown considered that Demand Side Management appeared to have worked well during the Varanus Island incident and noted that Simcoa had been called several times. The Chair reiterated his view that a workshop on the incident will be a very useful exercise. ***MAC Minutes*** Mr Dykstra noted that the draft minutes of MAC meetings were included in the papers distributed to MAC members before each meeting and also published on the IMO's website. Mr Dykstra considered that as these were draft minutes they should only be privately distributed to MAC members, and that MAC minutes should not be published on the website until they were final. The Chair replied that this would result in market stakeholders not seeing the minutes until they had been finalised, and that market stakeholders may need to reference these documents earlier, for example when preparing submissions for Rule Change Proposals. Mr Dykstra suggested that alternatively the draft minutes could be distributed to MAC members earlier for review. The Chair considered that it might be possible for the IMO to distribute the draft minutes to MAC members within a week of a meeting, so that MAC members could provide their comments within the following week, prior to the publication of the final minutes on the IMO website. ***Rule Change Process*** Mr Dykstra noted that he had made his views on the rule change process known on several occasions as he considers that this process needs to be examined. Mr Dykstra asked if any other MAC members shared his concerns. Mr Ken Brown questioned whether Mr Dykstra's concerns related to the level of detail in Rule Change Proposals. Mr Dykstra replied that he was concerned about the burden of proof that a proposal was consistent with or bettered the Wholesale Market Objectives, and also about the robustness of the processes the IMO adopts before proceeding to the formal consultation process. Mr MacLean questioned whether these concerns included Pre Rule Change Discussion Papers (PRCs). Mr Dykstra responded that he considered PRCs should be used to for the discussion of conceptual issues, and that the MAC was not intended to be a checker of the detail of the Amending Rules. Mr Dykstra stated that felt quite passionately about the issue.	

Item	Subject	Action
	The Chair suggested that Mr Dykstra should meet with him personally to discuss his concerns. Mr Cremin stated that he partially agreed with Mr Dykstra's concerns. Mr Cremin considered that MAC members can get "bogged down" in the MAC forum, although there had been good discussion at today's meeting. Mr Cremin noted that he found it difficult to go through the level of detail in the papers, but was not sure what should be done to address the problem. Mr Zammit noted that in other markets he deals with (such as the NEM) there is no body comparable to the MAC. Mr Zammit considered that the WEM was fortunate to have such a structure in place. Mr Dykstra queried the volume of rule changes in the other markets. Mr Zammit replied that in the NEM in particular he saw very few rule changes and that it was very difficult to progress a rule change in the NEM. Mr Dykstra considered that the NEM was not closed to applications for rule changes but that fewer rule changes were progressed because a higher burden of proof was demanded. Mr Dykstra considered that a larger number of rule changes were being seen in the WEM. Mr Zammit replied that the WEM was a younger market and so a greater number of rule changes could be expected. Mr Zammit considered that further evolution was needed in the NEM but was not happening. The Chair considered that the initial Market Rules were deficient, and the market is living with the consequences of this. The Chair considered that sometimes the deficiencies within the Rules were such that it was difficult for the IMO and System Management to determine how to comply with the Rules. The Chair reiterated that the IMO understood the burden imposed on MAC members, and noted the proposed technical review of the settlement equations for PRC_2010_27 was occurring to reduce this. The Chair also noted that the cost/benefit analysis due to be presented to the RDIWG next week had been prepared at a very detailed level. Mr MacLean queried at what time the following day the cost/benefit analysis would be distributed to RDIWG members. The Chair advised that the document would be distributed to RDIWG members before 11.00 am the next day. *Action Point: The IMO to distribute the cost/benefit analysis for the Market Evolution Program balancing proposal to RDIWG members before 11.00 am on 10 March 2011.*	**IMO**
12	**NEXT MEETING** Meeting No. 37 will be held on Wednesday 13 April 2011.	
CLOSED: The Chair declared the meeting closed at 5.08 pm.		

Agenda item 4: 2010/11 MAC Action Points

Legend:

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

#	Year	Action	Responsibility	Meeting arising	Status/Progress
119	2010	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	A workshop has been organised between the IMO and System Management to discuss the appropriateness of dispatch groups for DSM on 7 April 2011.
167	2010	System Management to distribute the results of Mr David Newton's work on Spinning Reserve requirements to MAC members	System Management	December	Completed. Circulated 9 March 2011.
12	2011	The IMO to remove criteria (b) and (c) from the proposed new clause 2.32.7B in the Pre Rule Change Discussion Paper: De-registration of	IMO	February	Completed. Currently out for its first submission period, closing 5

#	Year	Action	Responsibility	Meeting arising	Status/Progress
		Rule Participants who no longer meet registration requirements (PRC_2010_31), and then formally submit the proposal into the Rule Change Process.			May 2011.
14	2011	The IMO to work with EnerNOC to consider and respond to the comments received from MAC members on the Pre Rule Change Discussion Paper: Methodology for the Relevant Demand Calculation (PRC_2011_01).	IMO	February	A public workshop to discuss the alternative RD methodologies has been organised for on 8 April 2011. The workshop will include discussion of the points raised in comments received from MAC members.
18	2011	The IMO to amend the minutes of Meeting No. 35 to reflect the points raised by the MAC and publish on the website as final.	IMO	March	Completed.
19	2011	The IMO to remove Items 88 and 89 from the list of MAC action points.	IMO	March	Completed.
20	2011	The IMO to distribute the cost/benefit analysis for the Market Evolution Program balancing proposal to RDIWG members before 11.00 am on 10 March 2011.	IMO	March	Completed.

Independent Market Operator

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)	6 April 2011
Fast track with Consultation Period open	0
Standard Rule Changes with 1st Submission Period Open	3
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)	3
Standard Rule Changes with 2nd Submission Period Open	5
Standard Rule Changes with 2nd Submission Period Closed (final report being prepared)	0
Rule Changes - Awaiting Minister's Approval and/or Commencement	6
Total Rule Changes Currently in Progress	**17**

Potential changes logged by the IMO- Not yet formally submitted	February	March
High Priority (to be formally submitted in the next 3/6 months)	0	0
Medium Priority (may be submitted in the next 6/12 months)	22	22 (+0/-0)
Low Priority (may be submitted in the next 12/18 months)	20	20 (+0/-0)
Potential Rule Changes (H, M and L)	**42**	**42**
Minor and typographical (submitted in three batches per year)	37	39 (+2)
Total Potential Rule Changes	**79**	**81**

The changes in the rule change and issues log from February to March have arisen from:

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

APPENDIX 1: FORMALLY SUBMITTED RULE CHANGES

Standard Rule Change with First Submission Period Open

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2010_28	01/03/2011	Capacity Credit Cancellation	IMO	Submission period ends	13/04/2011
RC_2010_31	18/03/2011	De-registration of Rule Participants who no longer meet registration requirements	IMO	Submission period ends	05/05/2011
RC_2011_02	14/03/2011	Reassessment of Allowable Revenue during a Review Period	ERA	Submission period ends	12/05/2011

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	19/09/2011
RC_2010_25	29/11/2010	Calculation of the Capacity Value of Intermittent Generation - Methodology 1 (IMO)	IMO	Publish Draft Rule Change Report	20/05/2011
RC_2010_37	30/11/2010	Calculation of the Capacity Value of Intermittent Generation - Methodology 2 (Griffin Energy)	Griffin Energy	Publish Draft Rule Change Report	20/05/2011

Standard Rule Change with Second 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	15/04/2011
RC_2010_14	06/12/2010	Certification of Reserve Capacity	IMO	Submission period ends	11/04/2011
RC_2010_22	18/11/2010	Partial Commissioning of Intermittent Generators	IMO	Submission period ends	15/04/2011
RC_2010_29	02/02/2010	Curtailable Loads and Demand Side Programmes	IMO	Submission period ends	15/04/2011
RC_2010_33	17/12/2010	Cost_LR	Verve Energy	Submission period ends	14/04/2011

Rule Changes Awaiting Commencement/Ministerial Approval

ID	Date submitted	Title	Submitter	Next Step	Date
RC_2010_11	15/10/2010	Removal of Network Control Services Expression of Interest and Tender Process from the Market Rules	IMO	Commencement	01/07/2011
RC_2010_19	25/10/2010	Settlement Cycle Timeline	IMO	Commencement	01/05/2011
RC_2010_20	08/10/2010	Market Fees	IMO	Commencement	01/05/2011
RC_2010_21	15/10/2010	Providing Price Related Standing Data to System Management	IMO	Commencement	01/05/2011
RC_2010_23	03/08/2010	Consequential Outage – Relief from capacity refund and unauthorised deviation penalties	Alinta	Commencement	01/05/2011
RC_2010_24	03/08/2010	Adjustment of Relevant Level for Intermittent Generation Capacity	Alinta	Commencement	01/07/2011

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.	• Final Report being prepared	• Final Report to be published	TBA
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.	• Final Report being prepared	• Final Report to be published	April 2011

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
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).	• Final Report being prepared	• Final Report to be published	April 2011
PC_2011_01	Procurement of Network Control Services	RC_2010_11[1] (Removal of NCS Expression of Interest and Tender Process from the Market Rules) removes the NCS expression of interest, tender and contracting processes from the Market Rules to allow a Network Operator to undertake these processes under the regulatory oversight of the Economic Regulation Authority. As this Rule Change Proposal removes the heads of power (and the requirement) for the Market Procedure the IMO proposes to revoke the Market Procedure in its entirety.	• Proposal submitted and currently out for consultation.	• Submissions close	28 April 2011

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

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
PC_2011_02	Data and IT Interface Requirements	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Include some minor and typographical amendments to improve the integrity of the Market Procedure; • Remove the minimum workstation requirements, specifically outlining just the recommended workstation requirements; • Clarify the internet explorer requirements for different versions of the Market Participant Interface; and • Update the IMO's Access Security section.	• To be submitted into the Formal Procedure Change Process	•	April 2011
PC_2011_03	Registration of DSPs and the association of NDLs (Transitional Arrangements)	This is a new Market Procedure for Registration of Demand Side Programmes and the association of Non-Dispatchable Loads it is a transitional Market Procedure specifying the processes to the followed by the IMO and Market Customers between 1 June 2011 and 1 October 2011, for: • Registering a DSP; • Linking a CL to a DSP; • Associating an NDL to a DSP; and • Reassigning Capacity Credits from one DSP to one or more other DSPs.	• Proposal submitted and currently out for consultation.	• Submissions close	9 May 2011
TBD	Prudential Requirements	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Include some minor and typographical	• Presented at the 2 February 2011 working group meeting.	• Formal submission into the Procedure Change Process (subject to any working group	April 2011

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
		amendments to improve the integrity of the Market Procedure; • Include amendments required as a result of two Rule Change Proposals: o RC_2010_11[2] Removal of Network Control Services (NCS) Expression of Interest and Tender Process from the Market Rules; and o RC_2010_36[3] Acceptable Credit Criteria; The IMO would like to note that the remainder of the Market Procedure is out of scope for the purposes of this Procedure Change Proposal, as the IMO is currently undertaking a more detailed process review regarding Prudential requirements. Any amendments resulting from this review will be presented to the Working Group.		comments)	
TBD	Undertaking the LT PASA and conducting a review of the Planning Criterion	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedures project; • Include some minor and typographical amendments to improve the integrity of the Market Procedure, including re-ordering some sections; and • Include both reviews required under clause 4.5.15 of the Market Rules (Planning Criterion and forecasting processes).	• Updating procedure as a result of 2 February 2011 working group meeting.	• Updated procedure to be presented at the next working group meeting, to be scheduled.	TBD

[2] Refer to www.imowa.com.au/RC_2010_11
[3] Refer to www.imowa.com.au/RC_2010_36

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
TBD	Reserve Capacity Security	The proposed updates are to: • Reflect the IMO's new format arising from its Market Procedure project; • Reflect the broader heads of power for the Market Procedure; and • Ensure consistency with the proposed Amending Rules under the following Rule Change Proposals that the IMO is currently progressing: o Reserve Capacity Security (RC_2010_12); o Certification of Reserve Capacity (RC_2010_14); o Capacity Credit Cancellation (RC_2010_28); and o Acceptable Credit Criteria (RC_2010_36).	• Presented at the 28 March 2011 working group meeting.	• Awaiting further comments from members due 11 April 2011.	11 April 2011
System Management Procedure Change Proposals					
PPCL0016	Commissioning and Testing	The proposed update is to amend the procedure to reflect the commenced RC_2010_37 'Equipment Tests'.	• Submissions closed 13 January 2011. • Final Report being prepared by System Management	• Final Report to be provided to the IMO for approval	
PPCL0017	Facility Outages	The proposed update is to amend the procedure to reflect the commenced RC_2010_05 'Confidentiality of Accepted Outages by System Management'.	• Submissions closed 13 January 2011. • Final Report being prepared by System Management	• Final Report to be provided to the IMO for approval	
PPCL0018	Dispatch	The proposed updates are to allow for discretion to be exercised in requesting daily dispatch profiles from Market participants with facilities smaller than	• Proposal submitted and currently out for consultation.	• Submissions close	8 April 2011

Change ID	Title	Brief overview of changes	Status	Next Step(s)	Date
		30 MW.			
PPCL0019	Monitoring and Reporting Protocol	The proposed updates are to provide further details around how System management will determine and review the annual Tolerance Range and any Facility Tolerance Ranges to apply for the purposes of clause 7.10.1 and 3.21 of the Market Rules. The proposed updates will ensure consistency with the requirements of RC_2009_22 and in particular the new clause 2.13.6K.	• Proposal submitted and currently out for consultation.	• Submissions close	8 April 2011

Agenda Item 7a: Working Group Overview

1. WORKING GROUP OVERVIEW

Working Group (WG)	Status	Date commenced	Date concluded	Latest meeting date	Next scheduled meeting date
Reserve Capacity 2007 WG	Closed	Feb 07	May 07	-	-
NTDL WG	Closed	Oct 07	Nov 07	-	-
Energy Limits WG	Closed	Dec 07	Jan 08	-	-
DSM WG	Closed	Jan 08	May 08	-	-
SRC WG	Closed	Jun 08	Sept 08	-	-
Reserve Capacity 2008/09 WG	Closed	Dec 08	Jan 09	-	-
Renewable Energy Generation WG	Closed	Mar 08	Nov 10	-	-
System Management Procedures WG	Active	Jul 07	Ongoing	28/10/2010	TBA
IMO Procedures WG	Active	Dec 07	Ongoing	28/03/2011	TBA
Maximum Reserve Capacity Price WG	Active	May 10	Ongoing	24/03/2011	05/05/2011
Rules Development Implementation WG	Active	Aug 10	Ongoing	05/04/2011	03/05/2011

2. WORKING GROUP MEMBERSHIP UPDATES

In accordance with the Terms of Reference (ToR) the Market Advisory Committee (MAC) must approve the appointment and substitution of members for the Rules Development Implementation Working Group.

The MAC has received a request for Wana Yang to replace Chris Brown as the ERA's representative.

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

3. RECOMMENDATIONS

The IMO recommends that the MAC:

- **Agree** with the proposed amendment to the membership of the RDIWG.

Agenda Item 7b: MRCPWG Update

1. RECENT PROGRESS

The Maximum Reserve Capacity Price Working Group (MRCPWG) last met on 24 March 2011. The IMO has scheduled the next Working Group meeting for 5 May 2011.

At the March meeting, the MRCPWG broadly endorsed the methodology recommended by Sinclair Knight Merz (SKM) in its research report for determining the transmission connection costs. This calculation methodology uses a period-weighted average of historic connection costs, taken from real costs for historic projects and access offers for projects yet to occur, to indicate a level of future connection costs. The research report indicates that this methodology, if employed for the 2011 Maximum Reserve Capacity Price (MRCP) review, would have resulted in a transmission connection cost estimate of approximately $127,953 per MW subject to validation of the input data. This would represent a reduction of 58% from the value that was incorporated in the 2011 MRCP.

The MRCPWG also considered the methodology for determination of the Debt Risk Premium (DRP), which is used in the calculation of the Weighted Average Cost of Capital (WACC). Fair yield curves from Bloomberg and CBASpectrum have historically been used by regulatory authorities to estimate 10-year bond yields. However, regulatory practice is changing due to limitations in the availability of data from these organisations and concerns regarding the accuracy of Bloomberg data. Dr Duc Vo from the Economic Regulation Authority (ERA) presented the methodology recently employed by the ERA in its final decision for WA Gas Networks (WAGN)[1], which estimates the DRP from a selection of bond yields. The MRCPWG noted that the WAGN decision was the first time that this methodology had been employed in Western Australia and that the decision has been appealed to the Australian Competition Tribunal. Given the current evolution in regulatory practice, the MRCPWG deemed it appropriate that the Market Procedure should instruct the IMO to determine the DRP in accordance with recent regulatory practice.

The MRCPWG also agreed that:

- the Fixed O&M cost component should include an allowance for insurance to cover the replacement cost of the Facility; and
- the size of the land parcel should align with available lot sizes at each location.

The IMO presented a draft Market Procedure to the MRCPWG for consideration and has received out-of-session comments.

Following a recommendation by the MRCPWG at the 17 February 2011 meeting, the IMO has appointed WorleyParsons to provide independent advice regarding the development of the margin M (covering legal, financing, approvals and other costs) and forward escalation

---

[1] *Final decision on WA Gas Networks Pty Ltd proposed revised access arrangement for the Mid-West and South-West Gas Distribution Systems*, 28 February 2011, available at http://www.erawa.com.au/cproot/9382/2/20110228%20Final%20decision%20on%20WA%20Gas%20Networks%20Pty%20Ltd%20proposed%20revised%20access%20arrangement%20for%20the%20MW%20and%20SW%20GDS.pdf

factors. The IMO expects this work to be completed in time for consideration by the MRCPWG at the 5 May 2011 meeting.

2. UPCOMING MRCPWG MEETING

The 5 May 2011 meeting will consider:

- the methodology for determination of the margin M;
- the use of forward escalation factors for translating costs to June in Year 1 of the relevant Reserve Capacity Cycle;
- a report by the IMO detailing the impact of any change in the capitalisation period (currently 15 years), including changes in maintenance and other costs; and
- an updated draft Market Procedure.

3. PROCEDURE CHANGE PROPOSAL

Following the discussion of the updated draft Market Procedure at the 5 May 2011 meeting and incorporation of any agreed amendments, the IMO recommends that the draft Market Procedure be submitted into the Procedure Change Process. The IMO proposes to provide an extensive update to the MAC meeting explaining the significant changes to the MRCP methodology that have been agreed by the MRCPWG and incorporated into the Procedure Change Proposal.

4. RECOMMENDATION

It is recommended that the MAC:

- **note** this update; and
- **discuss** the IMO's recommendation with regard to the submission of the Procedure Change Proposal.

imo Independent Market Operator

Agenda Item 9: Balancing and Load Following Ancillary Services Recommendation Paper

1. PURPOSE

This paper sets out the key issues and recommendations from the Rules Development Implementation Working Group (RDIWG) regarding the Balancing and Load Following Ancillary Services in accordance with the RDIWG's Terms of Reference approved by the Market Advisory Committee (MAC) in August 2010.

2. BACKGROUND: ISSUES WITH THE CURRENT WHOLESALE ELECTRICITY MARKET

Since the Wholesale Electricity Market (WEM) was established in 2006, the opportunity for Market Participants to be engaged in the provision of energy beyond the STEM has been limited. Verve Energy has had the role of default balancer, while the opportunity for Independent Power Producers (IPP) to provide balancing energy has been restricted to occasions such as times when there has been a shortfall between the market's requirements and Verve Energy's supply capacity or when Verve Energy ran out of non-liquid plant or when system security requirements cannot otherwise be maintained (as covered by clause 7.6 of the Market Rules).

In feedback gained during consultation undertaken by the Independent Market Operator (IMO), privately owned Market Participants expressed a need to improve the current balancing mechanism to allow the opportunity to participate in the provision of balancing, while the current default balancer and others expressed concerns regarding the existing balancing pricing method. The MAC was presented with a list of the issues of concern in relation to the WEM – and following a prioritisation procedure – improving the balancing mechanism was identified as the top priority in August 2009[1].

The Verve Energy Review - commissioned by Government to assess why Verve Energy was in a loss-making position - critiqued the market similarly. It identified issues around the lack of competition in aspects of the market caused by the current market design.

The MAC was then presented with advice on pathway options for progressing some of these issues (particularly around balancing) and agreed in August 2010 that:

> "*Initial development work should assume the retention of the current hybrid market design, evolving the design as far as practicable, prior to considering exploration of further market design options". (MAC Meeting Minutes August 11, 2010.)*

The IMO Board accepted the MAC's advice but considered that a detailed review of all the design changes (including those addressing competitive balancing) should be made available to the Board no later than June 2011 to ensure the priority issues identified were

[1] Refer to the Market Rules Evolution Plan: www.imowa.com.au/market-rules

capable of being effectively and efficiently addressed under the hybrid model. Should the Board consider this not to be the case then it could ask for an assessment of more fundamental WEM re-design options.

The MAC then established the RDIWG to investigate a list of 10 issues confronting the WEM including the issues surrounding balancing pricing and provision.

The RDIWG's Terms of Reference are attached in Appendix 1 and the relevant MAC and RDIWG decisions pertaining to balancing and load following ancillary services are attached in Appendix 2.

3. WORK DONE TO DATE

In meetings since August 2010 the RDIWG has worked on a number of areas as identified in its work program. In relation to balancing and load following ancillary services, it has:

i. assessed the issues confronting the current calculation of MCAP balancing prices and agreed in principle that the new balancing price should only include balancing resources and that the DDAP and UDAP penalties should be removed or lowered (RDIWG Meeting 3, September 30 2010);

ii. assessed the merits of resolving the balancing pricing issues separately from the competition issues and acknowledged the IMO's recommendation that they not be pursued separately (RDIWG Meeting 3, September 30 2010);

iii. agreed to further explore the implications of the new balancing market proposal and to ascertain its operational and system impacts and its high level costs and benefits (RDIWG Meeting 6, November 23 2010);

iv. agreed not to pursue two simpler balancing market proposals presented by System Management given concerns particularly from generator representatives, that the proposals would not provide enough flexibility for IPPs to participate. (RDIWG Meeting 10, March 15 2011); This followed on from earlier consideration of a similar proposal by a Griffin Energy representative which was found to be similarly too inflexible to enable competition;

v. noted that retention of the fundamental WEM design has been assumed to mean:

   a) Bilateral contracts between Generators and Market Customers as the basis for commercial and physical participation in the WEM.

   b) Opportunities for Market Participants to adjust their bilateral positions through the STEM.

   c) Energy supplied in the market determined by:
      a. IPPs operating their facilities in accordance with resource plans (subject to dispatch by System Management – net dispatch); and
      b. Verve Energy as default provider of balancing and ancillary services on a portfolio basis.

   d) Continuance of the System Management / Verve Energy relationship (portfolio based, gross dispatch) (Meeting 10, March 15 2011);

vi. agreed that it should be made clear that the proposal incorporates opportunities for IPPs to participate in the trading of energy beyond the STEM - i.e. around Verve Energy's net contract position and/or each other's positions - as well as with variations from this net contract position caused by differences in load or unplanned outages; and

vii. agreed to the following further key principles for the design of the new balancing arrangements (RDIWG Meeting 10, March 15 2011):

	Principle	*Relevance*
1.	Providing opportunities for all Market Participants[2] to participate in the energy market beyond the day-ahead STEM and in load following ancillary services where that makes economic sense., noting that the proposal is targeted towards enabling Market Generators to participate in balancing in the first instance..	Consistent with Market Objective (b) and RDIWG Terms of Reference (1)
2.	Enabling price-based dispatch of resources beyond the day ahead STEM through simple offers/ bids/ flexibility to manage resources efficiently.	Consistent with Market Objective (a)
3.	Ensuring that the price and payments for energy trading beyond the STEM to reflect the marginal cost of dispatch to the extent practical.	Consistent with Market Objective (a) and with RDIWG Terms of Reference (3)
4.	Ensuring that Market Participants receive payment in line with prices offered to the market when dispatched by System Management for balancing support or LFAS.	Consistent with Market Objective (a) and RDIWG Terms of Reference (3)
5.	Providing timely and accurate forecasts of market prices and expected operation to assist/ inform decision-making.	Consistent with Market Objective (a) and RDIWG Terms of Reference (8)
6.	Ensuring that System Management receives no less information and has no less authority to ensure security and reliability of power system operation.	Consistent with Market Objective (a) and generally accepted principles with operating electricity markets
7.	Reducing reliance on financial penalties to incentivise compliance with moving towards a more traditional surveillance /compliance based regime.	Consistent with Market Objective (b) where the financial penalties are likely to be imposing unnecessary costs and a compliance regime can target poor behaviour more directly
8.	Ensuring to the extent practical consistency with possible future market development options.	Consistent with Market Objective (d)

These decisions are attached in Appendix 2.

4. OUTLINE OF THE PROPOSAL

Under the proposal now recommended by the RDIWG, IPPs would continue to submit resource plans and Verve Energy would continue in the role of default balancer. However, IPPs would be able to submit offers and bids into the market for dispatch upwards or downwards.

Verve Energy would submit prices for balancing on a portfolio basis a day ahead. Other Market Participants would have the ability to submit offers/bids on a facility basis a day ahead and update them up to two hours ahead of the time of supply.

The offers and bids would form a supply curve that would determine which producer (Verve or IPP) would supply electricity and at what market price. The IMO would send this 'balancing (dispatch) merit order' to System Management to dispatch generation.

Verve Energy would have the opportunity to take individual facilities out of its portfolio and bid them in on a facility basis. Verve facility bids would be treated the same as IPP facility bids.

The "clean" pricing arrangements would replace the current MCAP methodology – and the UDAP/DDAP penalties would be removed and replaced with an enhanced compliance regime.

In process terms, the bilateral submissions and STEM process would operate as now and IPP's would continue to submit resource plans (albeit with some minor changes in content). System Management would prepare the initial Verve dispatch plan as now (taking account of resource plans, wind/ demand forecasts and Verve guidelines) although it would do this later in the trading day.

Late in the afternoon, Market Participants would make initial offers/bids for the following trading day. Verve would submit its portfolio supply curve along with any individual facility offers/bids for each half hour interval the following day trading day. . IPPs would submit their facility offers and bids based on their resource plans (or gross offers for a facility not in service) for the same time periods.

The IMO would combine all offers and bids to establish the balancing (dispatch) merit order for each trading interval.

IPPs would operate to resource plans unless dispatched off plan by System Management. System Management would schedule facilities within the Verve portfolio as now in accordance with the Verve guidelines (rescheduling if need be to remain within the guidelines, to account for IPPs in the balancing merit order and/ or for system security purposes).

System Management would use the balancing merit order to the extent practical for dispatch purposes (noting discretion for system security purposes) and would advise the IMO of any IPP quantities it has dispatched.

The IMO would establish the marginal price from the total generation that was required and the final balancing merit order that was used by System Management for the interval. The IMO would identify, from the dispatch information supplied by System Management, any out of merit dispatch and establish unauthorised deviations.

IPPs that were dispatched above their resource plans by System Management (authorised) would receive the marginal balancing price (or constrained on payment if necessary). IPPs that were dispatched below their resource plans by System Management (authorised) would pay the marginal balancing price (or constrained off payment if necessary). Verve would be paid/ pay the marginal balancing price for quantities above/ below its Net Contract Position. IPPs with unauthorised deviations would face the marginal balancing price (i.e. no UDAP/DDAP) for the deviations but be required to provide bona fide reasons for compliance purposes.

The full proposal set out in “12 process boxes” is attached as appendix 3 to this paper.

A model of key aspects of the proposal has been developed and is now being trialled by a number of Market Participants.

5. OUTSTANDING ISSUES

A number of issues are outstanding with the proposal. These are as follows, along with the RDIWG recommendations for dealing with them:

Issue	*RDIWG Recommendation*
Gate closure times	An initial design target outcome would be two hours for those Market Participants bidding by facility – although there may need to be a transition to allow development of dispatch tools and experience.
Verve Resubmission	Proposal is for Verve to be able (initially at least) to resubmit at 8am for the remainder of the trading day (6 hours ahead) and at 5pm for the next trading day. It is also proposed that Verve should be able to resubmit in the event of a plant failure.
Timing of rollout of new Load Following Ancillary Services (LFAS) market	MAC previously agreed to the balancing and LFAS market proposals being developed together. It is going to be much easier and less expensive to design the balancing and LFAS systems in tandem at the same time. The LFAS selection process itself could be relatively simple to begin with and then replaced by software over time.
Timelines and milestones	The IMO target date is 1 December 2011 for the rules and systems to be in place – for the purposes of a market trial. The target date for full implementation was revised to the 1 April 2012 following discussions with System Management. The IMO will keep this date under review working with System Management and Market Participants.

6. CONSISTENCY WITH THE WHOLESALE MARKET OBJECTIVES

The RDIWG is required to report back on the consistency of the proposal with the Wholesale Market Objectives. The following sets out the implications of the new arrangement from an initial IMO perspective:

Wholesale Market Objective	***New proposal - implications***
To promote the economically efficient, safe and reliable production and supply of electricity and related services in the South West inter-connected system (SWIS);	The proposal would improve the efficiency of the operation of the WEM through greater competition, which is likely to drive down cost, through the provision of better investment incentives into the future. The proposal would also improve options available to SM over time in ensuring system security and reliability and will, in no way, limit System Management's ability to response to reliability or security events.
To encourage competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors;	The proposal opens up balancing and load following ancillary services to competition – particularly among generators
To avoid discrimination in the 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 proposal does not discriminate among different energy options or technologies.
To minimise the long-term cost of electricity supplied to customers from the SWIS;	The proposal will be more likely to achieve this than the status quo given the benefits of competition and the associated investment signals.
To encourage the taking of measures to manage the amount of electricity used and when it is used	The proposal will have no direct impact on this but provide a greater opportunity for this to be managed more effectively over time by providing clearer balancing price signals from the WEM and better forecasts of such prices.

The above indicates the proposal is consistent with the Wholesale Market Objectives.

7. IMPACTS ON THE CURRENT WEM

The RDIWG is required to report on the proposal's impact on the current WEM and physical operations.

Overall the new balancing market proposal will:

- enable greater participation in balancing, including opportunities for economically efficient rebalancing (following the one shot STEM process);
- provide a cleaner market price for balancing;
- replace current UDAP and DDAP with a more comprehensive a compliance monitoring regime;
- ensure that those contributing to balancing or the need for balancing are exposed to the positive or negative impacts of their decisions, provide System Management more facilities for managing balancing and LFAS;
- provide the opportunity for Verve Energy to move to individual facility based offers/bids over time;
- provide more options for System Management to manage system reliability in out-years but require changes to its procedures and systems in the interim that may have some implementation risks;

- have no impact on System Management's powers to manage security risk events;
- extend the life of current hybrid market arrangements; and
- involve additional costs for System Management, Market Participants and the IMO.

8. HIGH LEVEL COST BENEFIT ASSESSMENT

An independent high level Cost Benefit Assessment (CBA) of the balancing proposal estimates a range of quantifiable operational benefits to costs as follows:

	Low	Medium	High
Total benefits	$24.92 m	$27.92 m	$32.48 m
Total costs	$22.83 m	$19.27 m	$15.72 m
Net benefits	$2.09 m	$8.65 m	$16.76 m
Benefit-cost ratio	1.09	1.45	2.07

The direct costs associated with the proposal were predominantly the system costs for System Management and Market Operator and on-going (typically labour) costs. The quantifiable benefits covered:

(i) The ability by IPP's to bid in lower cost balancing capacity;

(ii) The marginal increase in the bidding of capacity given greater confidence arising from having flexibility to resubmit in response to evolving market conditions;

(iii) The return of capacity from outages; and

(iv) The fewer curtailments of base load generation.

Additional benefits were identified by way of better investment incentives for balancing-type capacity, learning over time, and through greater investment certainty.

Notably, the CBA indicates that there are benefits that were not able to be quantified that are likely to be more significant than the above figures. These benefits particularly relate to better investment incentives in relation to new generation investment, which could provide significant benefits to the WEM over a much longer timeframe.

The revised CBA reflecting RDIWG feedback is attached as appendix 4 to this paper.

9. MARKET POWER

The current mechanisms for mitigating potential market power will continue for the operation of the new balancing and load following ancillary service markets i.e.:

Market Participants will continue to be required to price at short run marginal cost when exerting market power i.e. the Market Rule obligation will remain unchanged. The current Rule requires:

6.6.3. A Market Generator must not, for any Trading Interval, offer prices within its Portfolio Supply Curve that do not reflect the Market Generator's reasonable expectation of the *short run marginal cost of generating the relevant electricity <u>when such behaviour relates to market power</u>.*

The STEM maximum and minimum price caps will also apply in the balancing (dispatch) and load following ancillary service markets as they do already for IPP balancing data submissions.

Should the proposal proceed to the rule change process, the IMO Board has requested an independent assessment of the market power implications to be available to it when assessing the draft rule changes.

10. MAC COMMENT

The MAC must now consider this advice and make a decision about what to recommend to the IMO Board. With this in mind it is worth noting that the new proposal:

- appears consistent with the RDIWG's Terms of Reference and the Wholesale Market Objectives;
- appears to be the most effective option thus far identified that will enable IPPs to participate effectively in balancing but in a way that is still consistent with the current hybrid design;
- appears technically feasible with no obvious outstanding "core concept" questions that remain to be answered while some detail remains to be resolved during preparation of the draft rules;
- provides net benefits according to the CBA; and
- has been developed within the IMO – MEP budget, noting there will be budget implications for any delays experienced in delivering the programme.

11. IMPLEMENTATION TIMING

The IMO has prepared an indicative implementation timetable should a decision be taken to proceed. This involves progressing the rule change work simultaneously with the operational and systems' development work commencing as soon as a decision is made. The aim would be to have a market trial operating before the end of 2011 and the new balancing and LFAS markets in operation by April 2012. These dates are flexible, however, subject to the budget for the program – and the IMO would seek to confirm/amend these dates with a more detailed implementation plan if a decision to proceed is made.

12. RDIWG MEMBERS VIEWS

At its most recent meeting last week, the RDIWG discussed its likely advice to the MAC on this proposal. Individual views were as follows:

J Rhodes: Support sending it to MAC on the presumption that retailers will be able to amend contracts and extract benefits. Also a question as to whether the RDIWG can do anymore;

C Parrotte: (standing in for *P Kelloway*): Can't support all recommendations, need more detail e.g. around the Cost Benefit Analysis, more work on roles/systems needed, respect that this paper is principles, timing is still a concern for System Management;

A Everett: Supportive of competitive balancing, supportive of design, proceeding on good faith with regards to the detailed design process;

S Cremin: Proposal is adding sophistication to the market, this will force change/rebidding etc. Supportive;

A Sutherland: Supportive, providing not limiting ourselves with regards to gate closure. Has concerns still around STEM, but noted that this is outside the scope of this work;

P Hynch: Supportive. Interested in non-quantifiable benefits. Support the move to more light handed regulation (re removal of UDAP and DDAP);

G Gaston: Can't participate currently. Fully supportive.

C Dykstra: Noted that it seemed to be the most effective option available but in light of the low net benefits and the risks, did not consider it worth pursuing. Not supportive.

S Gould: From a smaller retailer's perspective will provide benefits. Strongly support.

In light of this, the Chair resolved to proceed to recommend this proposal to the MAC.

13. RECOMMENDATIONS

It is recommended that the MAC:

a) Note the RDIWG's Terms of Reference as set out in Appendix 1;and the previous MAC and RDIWG decisions set out in Appendix 2;

b) Note the balancing and LFAS proposal as it now stands – in terms of key components or principles as set out in sections 3, 4 and 5 of this paper – and the fuller description of the proposal as set out in Appendix 3;

c) Note the proposal:

i. appears consistent with the RDIWG's Terms of Reference and the Wholesale Market Objectives;

ii. appears to be the most effective option thus far identified that will enable IPPs to participate effectively in balancing but in a way that is still consistent with the current hybrid design;

iii. appears technically feasible with no obvious outstanding "core concept" questions that remain to be answered while some detail remains to be resolved during preparation of the draft rules;

iv. provides net benefits according to the CBA;

v. has been developed within the IMO – MEP budget, noting the budget implications for any delays experienced in delivering the programme;

d) Note that existing mechanisms for mitigating potential market power would continue to apply to the new proposal and the IMO Board has asked for an independent assessment of market power issues should the decision be made to proceed with the proposal;

e) **Recommend** to the IMO Board the creation of new balancing and LFAS markets in accordance with the principles and concepts set out in Sections 3, 4 and 5 of this paper;

f) **Recommend** to the IMO Board that the fuller Balancing and LFAS design proposal paper attached separately be used as the basis for initial rule changes and system and operational development in implementing the new balancing and load following ancillary service markets;

g) **Note** that the ability to make significant changes to the proposal beyond this decision point will be more limited given the system design and cost implications but it will be possible to amend detailed aspects of the proposal during this rule consultation phase – as long as the changes do not revisit core aspects of the design;

h) **Recommend** to the IMO Board that any amendments to the design as set out in Balancing and LFAS design proposal paper attached separately should be consistent with the principles and concepts set out on sections 3, 4 and 5 of this paper and assessed according to their cost and related system development implications before being agreed; and

i) **Note** that the current target date for a market trial of the balancing market is 1 December 2011 and target date for a full roll out is 1 April 2012 but these dates can be confirmed closer to the time working with System Management and Market Participants subject to consideration of the budgetary implications.

APPENDIX 1: TERMS OF REFERENCE FOR THE RULES DEVELOPMENT IMPLEMENTATION WORKING GROUP

1. BACKGROUND

The Rules Development Implementation Working Group (Working Group) has been established, in accordance with Clause 2.3.17 of the Wholesale Market Rules and the associated Section 9 of the Constitution of the Market Advisory Committee (MAC). Consistent with these authorised functions and powers, the overarching function of *any* Working Group established under the MAC is to assist the MAC in providing advice to the Independent Market Operator (the IMO) and System Management in matters relating to Wholesale Electricity Market (WEM) Rule and Procedural Change Proposals, WEM operation and South West interconnected system (SWIS) operational matters, and the evolution of the Market Rules more generally.

2. SCOPE

The Working Group's Scope of Work includes consideration, assessment, development and post-implementation evaluation of changes to the Market Rules associated with the issues list agreed by the MAC at its 11 August 2010 meeting. This issues list is attached as attachment 1 to this document.

3. TERMS OF REFERENCE

The Working Group is to:

- Prioritise the issues agreed by the MAC into an appropriate number of development work streams;
- Agree a work plan and timeline for consideration of each of the work streams;
- Develop an integrated suite of solutions, including drafted Concept Papers and Rule Change Proposals to be presented to the MAC by way of presentation/s and supporting discussion paper/s; and
- Undertake a post-implementation evaluation of the solutions, to identify any remaining shortcomings and recommend an approach to address them.

The Rule Change Proposal(s) must include a full impact assessment prior to any recommendations being put forward to the MAC, including:

- Consideration of the implications of any changes on improving the delivery of the Market Objectives;
- Detailed feedback as to the implications to the operation of the existing WEM processes and physical outcomes; and
- Consideration of the economic costs and benefits of implementation.

Consistent with Section 9.5 of the MAC Constitution, all matters which are identified as falling outside the Scope and Terms of Reference of this Working Group must be referred back to the MAC for consideration.

4. OBJECTIVES AND PRINCIPLES

The Working Group must provide advice and report the extent to which its advice meets or is consistent with the Wholesale Market Objectives and the general principles reflected in the current Market Rules.

The Market Objectives are as outlined in Section 122 of the Electricity Industry Act 2004 and Clause 1.2.1 of the Market Rules.

5. MEMBERSHIP

The Working Group consists of a Chair and members appointed by the IMO from nominees, being representatives of Rule Participants and other interested stakeholders. In addition, staff, representatives and consultants of the IMO work with and support the group. Replacement and/or new nominees can be submitted to the IMO for consideration at any time.

6. TENURES

The Chair and members are appointed by the IMO and remain in tenure until the appointment is duly revoked by the IMO or the Working Group is disestablished.

A member of the Working Group may resign by giving notice to the IMO in writing; this notice of resignation can include an appropriate replacement from the member's entity, for approval by the IMO.

7. RESPONSIBILITY OF THE CHAIR

The Chair provides guidance to the group to ensure that the outputs are appropriate and that they support the Working Group's role of providing advice to the MAC. The Chair works closely with the MAC, the IMO and the Working Group to achieve this.

In carrying out the above role, the Chair must ensure the documented output reflects a balanced representation of the group views.

8. RESPONSIBILITY OF MEMBERS

Members have been selected for their particular expertise and accordingly:

- Members are to make themselves available for meetings;
- Members have a duty to prepare for meetings;
- If sending alternates, members have a duty to ensure their alternates are sufficiently briefed and prepared for meetings;
- Members, or their alternates, are to consider the interests of all stakeholders currently operating within the WEM;

- Members, or their alternates, do not represent their own organisations (although the range of commercial and technical experience inevitably adds diversity to the group's capabilities); and

- Any views expressed by members, or their alternates, are not to be taken as being those of their employer or nominating organisation.

9. KEY TASKS AND MILESTONES – THE WORK PLAN

The Chair works with both the IMO and Working Group to develop the Work Plan, setting out the key tasks and milestones within the Terms of Reference.

The Chair has responsibility for the implementation of the approved Work Plan, efficient meetings of the Working Group and reporting to the MAC on achievement of agreed milestones.

10. NATURE OF DELIVERABLES

The Working Group delivers reports, advice and comments on the tasks within the scope of the Terms of Reference and as agreed and set out in the Work Plan. Such deliverables may be varied from time to time by direct request from the Chair of the MAC.

In some circumstances, the MAC may decide that comments, rather than advice, are required from the group. These circumstances may arise due to:

- Issue complexity and contentiousness;

- Parallel industry wide consultation; and

- Time frames.

The documented output in those circumstances would note the various issues raised by the group and advise on them.

11. REPORTING ARRANGEMENTS

Routine reporting will be via Working Group reports to the MAC. Consistent with section 9.4 of the MAC Constitution, the Working Group must report back to the MAC at each MAC meeting. The Chair will also personally report to the MAC at agreed key milestones.

12. ADMINISTRATION

The Working Group activities are to be as transparent as practical. The Chair must ensure that key decisions and action points from meetings are recorded.

ATTACHMENT 1: DESIGN ISSUES/PROBLEMS TO BE ADDRESSED

The design issues/problems to be addressed by the RDI WG are:

1. There is very limited opportunity for participants other than Verve to participate in providing balancing services and this inevitably means the cost of balancing is higher than it needs to be.
2. Provisions for Balancing Support Contracts have not been effective to date.
3. The calculation of MCAP and the role of UDAP and DDAP mean that balancing prices are not cost reflective and this leads to inefficient incentives for decisions about prices and participation and inequitable financial transfers between participants that compromise the integrity of the WEM.
4. At different times the capacity refund arrangements under and over price the value of capacity leading inefficient decisions by participants about the timing of maintenance and presentation of capacity.
5. The timing of operation and single pass design of STEM may be limiting the ability of the market to achieve efficient operation and cost reflective prices and accordingly creates a barrier for participation by all parties.
6. The requirement for resource plans to match STEM outcomes may be limiting participation in STEM and/or forcing inefficient dispatch of IPPs and Verve (as balancer) as IPPs attempt to comply with the resultant resource plans.
7. Poorly aligned gas and electricity mechanisms inhibits flexibility to respond to changing circumstances and produces suboptimal outcomes in the WEM.
8. Lack of transparency inhibits the ability of Market Participants to optimise interaction in the daily energy market.
9. Provision for net bilateral submissions compromises transparency and the accuracy of future price forecasts and may therefore lead to sub optimal decisions about participation by other market participants.
10. Pay as bid pricing for dispatch of IPP plant for balancing (outside a balancing support contract) is incompatible with efficient wider participation in balancing and potentially over compensates IPPs which bid at price caps due to uncertainty of dispatch outcomes.

An additional design issues/problem for noting (i.e. not part of the initial work of the RDIWG) is:

There is very limited opportunity for participants other than Verve to participate in providing Ancillary Services. This is due to the lack of certainty surrounding the pricing mechanism and the requirement to provide the service at a discount to Verve. System Management will look to develop a day-ahead procurement mechanism and present the outcomes of its analysis at the RDIWG.

APPENDIX 2: MAC AND RDIWG DECISIONS TO DATE

MAC and the RDIWG have made the following decisions to date in relation to balancing and load following ancillary services:

MAC Decision	Comment
Market Evolution Plan	*"Improved Balancing Mechanism" –- identified as Number 1 Priority in a vote by MAC members – as reported in August 2009.*
Retaining the fundamental WEM design, evolving it as far as practicable, before considering more fundamental change.	*"In particular, the MAC agreed that:* *Initial development work should assume the retention of the current hybrid market design, evolving the design as far as practicable, prior to consider exploration of further market design options."* *MAC Minutes, August 11 2010*.
RDIWG Terms of Reference (10 points)	*Of relevance to balancing:* *(1) There is very limited opportunity for participants other than Verve to participate in providing balancing services and this inevitably means the cost of balancing is higher than it needs to be;* *(2) Provisions for Balancing Support Contracts have not been effective to date;* *(3) The calculation of MCAP and the role of UDAP and DDAP mean that balancing prices are not cost reflective and this leads to inefficient incentives for decisions about prices band participation and inequitable financial transfers between participants that compromise the integrity of the WEM; and* *(8) Lack of transparency inhibits the ability of Market Participants to optimise interaction in the daily energy market.* *MAC Minutes, August 11 2010*
Incorporating a competitive LFAS market to work in conjunction with the balancing market recognising interdependencies between balancing and LFAS capacity to the extent practical.	*"MAC members agreed that the proposals for competitive Balancing and LFAS provision should be developed together as a package."* *MAC Minutes, Dec 15 2010*.

RDIWG decision	Comment
Balancing pricing	*The RDIWG:* *"Agreed in principle that the balancing price curve should only include balancing resources (i.e. clean pricing); and* *Agreed in principle that DDAP/UDAP should be removed, or set to lower levels, better reflecting impacts on balancing requirements."* *RDIWG Minutes, 30 September 2010*
Clean balancing pricing and competition as a package	*"The RDIWG discussed whether the introduction of clear pricing should be conditional upon achieving competition in the provision of balancing services and whether the removal or reduction of DDAP/UDAP could be progressed earlier. The RDIWG acknowledged the IMO's recommendation that these changes should not be pursued in isolation."* *RDIWG Minutes, 30 September 2010*
Further exploration of the Balancing market proposal	*"The RDIWG agreed that the proposal had merit and asked that the proposal be workshopped with operational staff, to identify and address any technical issues affecting the viability of the option and to have its benefits and costs assessed – at a high/summary level."* *RDIWG Minutes, 23 November 2010.*
Simpler Options	*The RDIWG agreed not to pursue two simpler balancing market proposals presented by System Management given concerns particularly from generator representatives, that the proposals would not provide enough flexibility for IPPs to participate.* *RDIWG Minutes, March 15 2011.*
Retention of the current decision	*The RDIWG noted that retention of the fundamental WEM design has been assumed to mean:* *a) Bilateral contracts between Generators and Market Customers as the basis for commercial and physical participation in the WEM.* *b) Opportunities for Market Participants to adjust their bilateral positions through the STEM.* *c) Energy supplied in the market determined by:* *a. IPPs operating their facilities in accordance with resource plans (subject to dispatch by SM – net dispatch); and* *b. Verve Energy as default provider of balancing and ancillary services on a portfolio basis.* *d) Continuance of the SM / Verve Energy relationship (portfolio based, gross dispatch)* *Principles paper discussed at RDIWG meeting, March 15, 2011.*
Principles for new arrangement	*1. Providing opportunities for all Market Participants to participate in balancing where that makes economic sense* *2. Enabling price-based dispatch of resources for balancing/rebalancing through simple offers/ bids/ flexibility to manage resources efficiently* *3. Ensuring that the balancing price and payments for balancing reflect the marginal cost of dispatch to the extent practical.* *4. Ensuring that Market Participants receive payment in line with prices offered to the market when dispatched by System Management for balancing support or LFAS.* *5. Providing timely and accurate forecasts of market prices and expected operation*

RDIWG decision	Comment
	to assist/ inform decision-making. 6. *Ensuring that System Management receives no less information and has no less authority to ensure security and reliability of power system operation* 7. *Reducing reliance on financial penalties to incentivise compliance with moving towards a more traditional surveillance /compliance based regime.* 8. *Ensuring to the extent practical consistency with possible future market development options.* *Agreement recorded in RDIWG Minutes, March 15, 2011.*

Appendix 3: New Balancing Market proposal – design details

1. INTRODUCTION

This document describes the key design features proposed for revised arrangements for short term operation of the Wholesale Electricity Market (WEM) in a manner that retains the core hybrid framework of the current design. This is where IPPs develop Resource Plans for their own facilities and System Management develops dispatch plans for the Verve Energy (Verve) portfolio. The design expands on the high level concept previously presented to the RDIWG at its 14 December 2010 meeting.

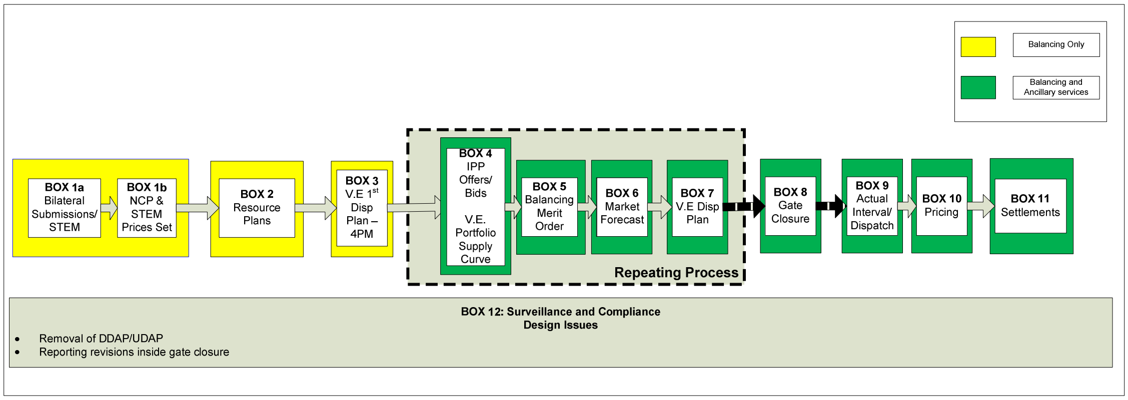
Sections 1 and 2 provide a high level overview (see figure 1). Section 3 provides additional detail of the proposed design in 12 stages.

Appendices A and B provides:

- A more detailed overview showing the roles and responsibilities for each process; and
- an example of the ability of the Balancing design to enable an IPP to de-commit a Facility if appropriate pricing conditions occur.

Finally, appendix C presents a glossary, which outlines the new defined terms that are being proposed in this design paper.

Figure 1: 12 stages of WEM operation



2. DESIGN SUMMARY

- The proposal is designed as an enhancement of the current hybrid design where IPPs are dispatched on the basis of Resource Plans and Balancing submissions (offers up/ bids down) around that level and Verve's portfolio dispatched by System Management on the basis of gross supply offers. The design also allows Verve to submit offers/bids for selected facilities.
- The design will allow for IPPs to participate in Balancing and provide for competitive provision of Ancillary Services.

- Verve will remain the default balancer and default Ancillary Service provider. System Management will continue to provide a dispatch coordination service to Verve and determine the dispatch of Verve's facilities on a portfolio basis in accordance with dispatch guidelines. As system and market conditions change (for example with weather, availability of fuel, capability of unscheduled wind generation) System Management will amend the Verve portfolio dispatch plan (as it does now), including commitment of units to optimise use of those resources whereas IPPs will renominate Balancing bids and offers. Verve will be able to restate its portfolio supply curve following major changes.

- The initial stages of operation of the market are little changed from the status quo (see the sections on bilateral and STEM submissions and operation of STEM – box 1a and 1b from Figure 1).

- Resource plans will be submitted by IPPs (and for any facilities Verve chooses to manage on a Facility basis). Resource plans will be broadly required to match Net Contract Position (NCP) and self-supplied Load (as now) except when the amount of energy (MWh) required by the NCP changes from one interval to the next. In these cases Market Participants will be entitled to elect to include Balancing energy on a planned basis around their Facility MW ramping rates.

- The first significant change to the design will be the introduction of submission of bids/offers for Balancing and Ancillary Service from IPPs and Verve. These submissions will follow the submission of Resource Plans and calculation of the first dispatch plan for Verve plant. IPPs will make these submissions on a Facility basis and Verve on a portfolio basis. The submissions will be for the full or gross potential Balancing range being offered and Ancillary Service capability and note where these might be mutually exclusive (or conditional) (see box 4).

- The market rules will describe the principles for deciding which Balancing offers/ bids and Ancillary Service offers will be selected for service from the conditional gross capabilities submitted (see box 5).

- The Balancing Merit Order (BMO) will be determined from the Balancing submissions taking account of accepted Ancillary Service offers (see box 5).

- IPPs and Verve will have specified rights to update Balancing and Ancillary Services submissions within nominated gate closure times (see box 8).

- System Management will continue to determine the timing of commitment and decommitment of Verve plant (other than facilities Verve has elected to manage outside its portfolio). In the first instance IPPs will manage commitment and decommitment of their facilities, as currently occurs (as expressed in Facility Resource Plans). However the design of the rules around resubmissions and gate closure will facilitate IPP participation in Balancing including decommitment when appropriate (see box 7).

- Non scheduled resources (e.g. wind) may submit an offloading price and will be incorporated in the Balancing Merit Order used by System Management at the time of dispatch.

- System Management will dispatch all plant to meet demand and ensure secure operating conditions are maintained in accordance with the final merit order. The Real Time Balancing Merit Order (RTBMO) is developed by updating the BMO and accounting for operational limitations advised to System Management (see box 9).

- The Balancing price will be determined ex post from the total generation requirements used and the RTBMO used for dispatch – no Upward Deviation Administrative Price (UDAP) or Downward Deviation Administrative Price (DDAP) factors will apply. Constrained on/off payments will be made for Facility offers/bids dispatched at prices inconsistent with their submissions (see box 10).

- System Management will retain wide authority to manage security of operation (see box 9).

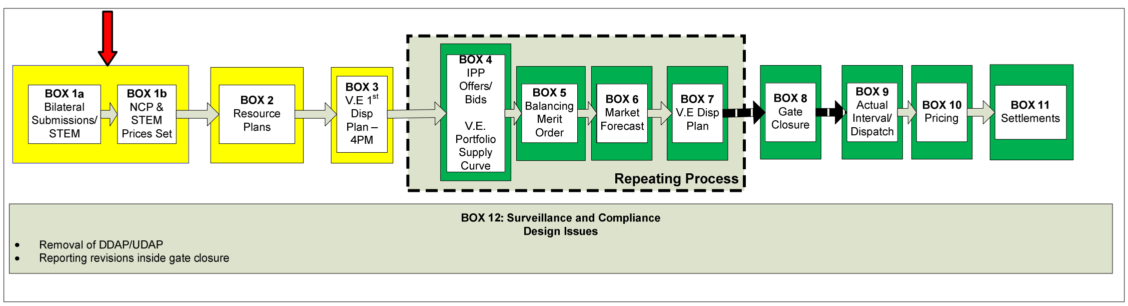
3. DETAILED DESIGN

The following pages describe each of the 12 stages in more detail. This current version of the paper provides only dot point summary of design details and later versions will be expanded with greater detail including rationale for design decisions.

3.1 BILATERAL SUBMISSIONS/STEM AND NCP AND STEM PRICES (Box 1)

3.1.1 Purpose:

This section describes the potential impacts on the current STEM process of implementing the new competitive Balancing market.



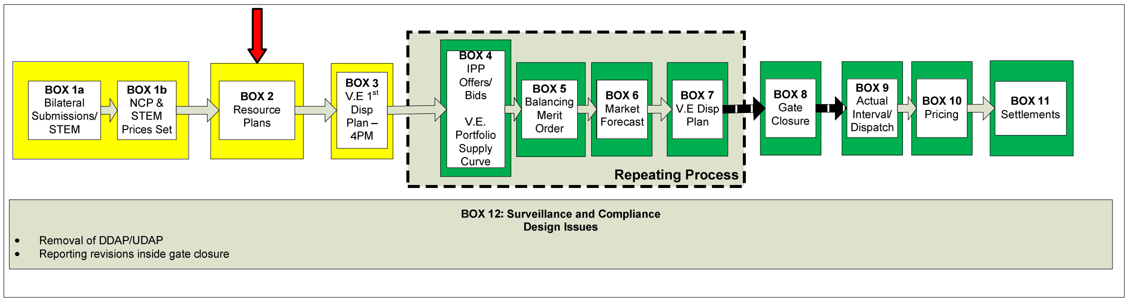
3.1.2 Proposal:

- No Changes to Current STEM process and setting of NCP.

3.2 RESOURCE PLANS (Box 2)

3.2.1 Purpose:

This section explains the role of Resource Plans (RPs).



3.2.2 Background:

Once accepted RPs can be seen as self issued Dispatch Instructions (DIs) that self scheduled facilities need to comply with in order to meet their NCPs and any self supplied load. Proposed RPs must be reviewed and accepted as technically viable by System Management from a system security perspective.

Currently, RPs state the energy (MWh) proposed to be generated in a Facility in each interval and this energy must match the total NCP and self supplied load of the relevant Market Participant.

No change to this general principle is proposed, however, the format of the submissions and the stringent requirement for energy within RPs to match NCP when NCP changes, is to be amended.

3.2.3 Proposal:

- Resource plans will be required for all IPP scheduled facilities (no change) and any facilities Verve elects to operate on a Facility basis. The sum of RPs submitted by a participant must match the participant's NCP plus self-supplied load except where this quantity is changing from one interval to the next:

- For each dispatch interval, RPs are to specify a MW target (sent out) with a specified ramp rate from a specified time:

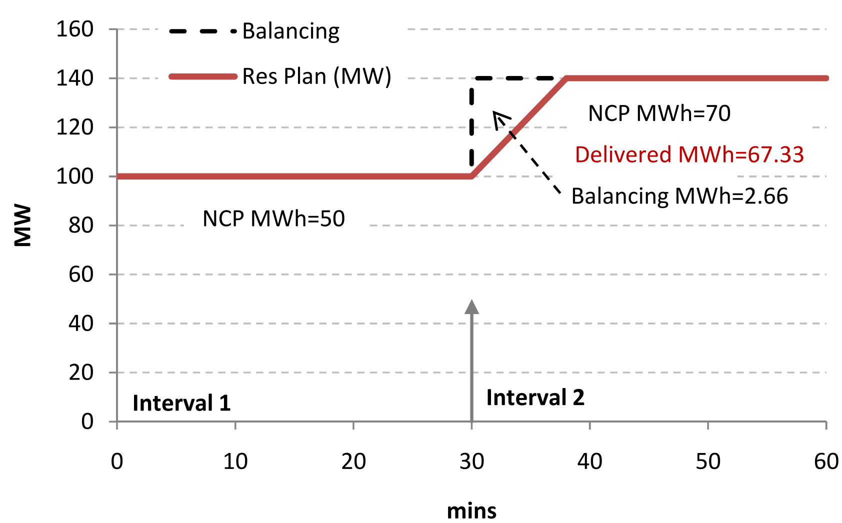
    - This will make the format of the implied self dispatch instructions through RPs consistent with the form of System Management dispatch instructions for Balancing in any interval (subject to development of necessary dispatch support tools).

    - Facilities operating to a RP will thus ramp up or down linearly in an interval and will be operating at a nominated level by the end of the interval.

    - The linear ramp rates must be realistic estimates of how the participant will dispatch the facility to meet the target level specified, accepting that for practical reasons a facility may not be able to ramp continuously at a uniform rate. However, the specified ramp rate should reflect the time the participant expects to take, from the start of the interval, to ramp to the specified target MW level.

- The RP will form the reference level for Balancing offers/bids.

- System Management will accept/reject RPs in response to system security concerns caused by RPs.
    - o The Market Rules and Market Procedures/ Power System Operation Procedures will specify under what circumstances and what actions System Management will use this judgement.
- RPs in each interval from each Market Participant must match the energy (MWh) in the corresponding NCP except when the NCP changes from one interval to the next.
    - o When NCP changes from one interval to the next a RP may indicate more or less energy than the relevant NCP, this may result in one of two scenarios:
        1. The total energy provided by the facility is less than NCP (if NCP is increases as illustrated below), or more energy is produced when NCP decreases, this scenario exposes a participant to balancing energy; or
        2. when NCP is increasing (or decreasing) a participant may chose to "overshoot" (or undershoot) the NCP implied MW value, in this scenario a participant will choose a MW target that is above the NCP implied MW value so that the energy produced is equal to the MWhs in the NCP
    - o The RP indicates ramping at 5 MW per minute at the start of interval 2 to a target of 140 MW, equivalent to the MW level implied by the 70 MWh NCP.

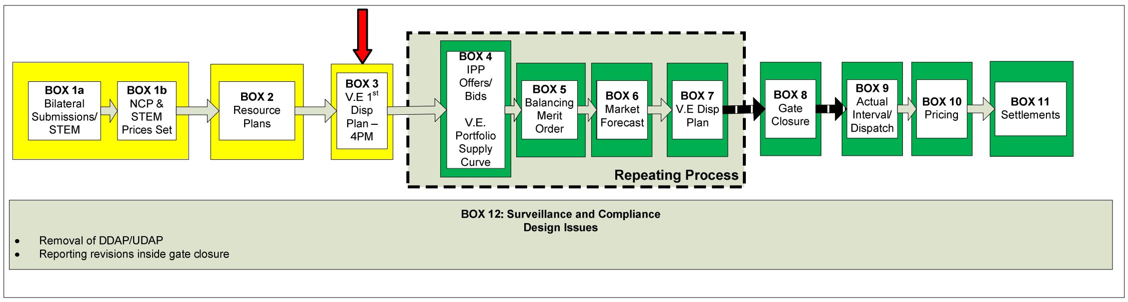


Note: RPs will contain sufficient information for half hour market processes and will not need to account for the level of Balancing or Ancillary Services that may be accepted by System Management. Bids and offers for Balancing and Ancillary Services will be submitted relative to the RPs. Renominations and operational protocols will provide for System Management to receive all information needed for secure operation of the power system through the Real Time Balancing Merit Order (RTBMO) and within half hour operational details e.g. short term interactions between Resource Plan ramping and Balancing capability (for additional information see Box 9).

3.3 VERVE ENERGY 1ST DISPATCH PLAN (Box 3)

3.3.1 Purpose:

This section explains the role of the first System Management created Verve Energy Dispatch Plan in the context of the implementation of the competitive Balancing market.



The Verve Energy Dispatch Plan is a service provided for Verve by System Management under the hybrid market design. System Management reviews and updates the dispatch plan as and when circumstances require.

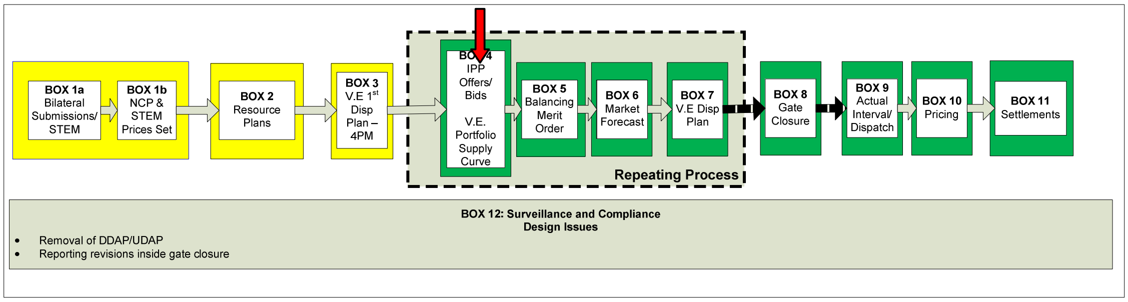
3.3.2 Proposal:

- The Market Rules will require System Management to provide dispatch plans in accordance with the Verve Dispatch Guidelines. As a minimum System Management must provide Verve an initial dispatch plan before Verve is required to submit Balancing offers/bids.
- The Rules will also need to ensure that System Management has the necessary information to account for expected IPP/Verve standalone Facility generation in preparing the Verve dispatch plan (e.g. refer forecasting box 6).

3.4 BALANCING OFFERS/BIDS AND VERVE ENERGY PORTFOLIO SUPPLY CURVE AND LOAD FOLLOWING ANCILLARY SERVICE OFFERS (Box 4)

3.4.1 Purpose:

This section explains how bids and offers will be formulated for Balancing and Load Following Ancillary Services (LFAS) from both IPPs and Verve Energy in the context of the implementation of the competitive Balancing market. Given that VE will remain the default balancer.



3.4.2 Proposal:

Form of bids and offers

- Initial bids/offers for Balancing and Ancillary Services to be submitted by Verve and IPPs at (say 4pm to 5pm).

- As a minimum, Verve will be required to submit a portfolio supply curve for each trading interval comprising multiple pairs of sent out MW and price per MWh for its available capacity. This curve will be required to be submitted at the same time as the first IPP Bids/Offers, approximately 4 or 5PM)

- Verve will be able to submit bids/offers the same as IPP facilities if Verve chooses to separate out a Facility (or facilities) from its portfolio (and reduce capacity offered in its portfolio accordingly). IPP (and Verve stand alone facilities) bids/offers on a Facility basis stating MW range, price:

    - IPPs *must* submit a price for dispatch above Resource Plan up to the full capacity of each Facility (no change from current).

    - IPPs *may* divide the capacity between Resource Plan and full capacity into up to [5] bands – these will form the basis for upward Balancing tranches in the Balancing merit order.

    - IPPs must submit a price for dispatch below Resource Plan including for decomittment (no change from current arrangement for a price within standing data for emergency de-commitment).

    - IPPs *may* divide the capacity below Resource Plan into up to [5] bands. These will form the basis for downward Balancing tranches in the merit order. Strongly negative prices would be expected below minimum load of generators seeking to avoid decommitment.

All capacity expected to be available from a Facility must be included in bids/offers

- Intermittent and non scheduled resources that can only control reduction in output will be able to provide a price for Balancing down. – System Management will dispatch these resources down to the extent of prevailing output at the submitted price (e.g. wind facilities might submit a bid (unspecified quantity) at –ve $40 and System Management will dispatch the prevailing output down if the price would otherwise fall below–ve $40. (Also see boxes 5, 6 and 9).

Ancillary Service offers:

Registered (technically pre qualified) IPP and Verve standalone LFAS Facilities may submit:

- an enablement price ($/MW),
- upward capability (MW),
- downward capability (MW); and
- Steady State Ancillary Service Base point (SSASB) a pre loading quiescent operating level (MW). The SSASB will reflect the any pre loading required when no Ancillary Service is being called on (e.g. system frequency at 50Hz) but is needed in order for the relevant Facility to be capable of providing the service such as part loading of gas turbines.

Verve Energy will be required to submit a portfolio supply curve for the provision of LFAS including:

- An enablement price per tranche ($/MW);
- upward capability per tranche (MW); and
- downward capability per tranche (MW).

Joint Balancing and Ancillary Service Conditions:

Offers (by IPP and verve stand alone Facilities) to provide Balancing and Ancillary Services will be presumed to be mutually exclusive and that Market Participants will be indifferent about which (if either) service is accepted based on the prices submitted. This will mean that a Balancing offer for +/- 30MW and LFAS offer of +/- 20MW can be made for a Facility with a capacity of 200MW providing the Resource Plan is for no more than 170MW. Market systems will determine which combination of Balancing and LFAS it is appropriate to accept at the time of dispatch e.g. 30MW Balancing with 0MW LFAS or 10MW Balancing and 20MW upward LFAS. Final selection will be made by System Management on the basis of data available just prior to time of dispatch.

An alternative approach whereby ancillary service providers would be pre-determined would require a separate consideration of offers to provide ancillary services and for those parties whose offers were accepted to submit resource plans and balancing offers adjusted for those offers. Consistency between capacity, resource plans, balancing and ancillary service amounts would need to be validated. An additional market process would need to be introduced.

Because submissions for provision of balancing and ancillary services are to be made simultaneously and are to be conditional, the submissions from participants will be relatively simple. Market systems (software) will be used to select the combination of successful providers and this selection process can be relatively simple or involve complex trade-offs between balancing and ancillary services. Such a framework allows for simple initial arrangements that can be refined over time by changing the design of the software support within market processes used by both IMO and System Management without need for subsequent changes to submissions.

Importantly details of the timing of submissions, resubmissions and reassignment of ancillary service duty should be chosen to align with the broader balancing market design and design of software support and processes used by System Management.

Resubmissions:

In order to ensure System Management is presented with accurate information about the quantity available from each Facility and to ensure the prices for dispatch of Verve and IPP resources reflect changes in costs across each day:

- Verve will be eligible to re-submit its Portfolio Supply Curve at the beginning of the trading day (say 8 am) and/or when a Facility within the PSC experiences a demonstrable physical outage to one of the Facilities within the Portfolio Supply Curve.
- IPPs and Verve (in respect of resources it elects to submit on a Facility basis) may re-submit up to specified rolling gate closure times (see box 8).

Assessment of conditional Balancing and Ancillary Service offers:

The objective of the assessment is to determine as close to optimum mix of Balancing and Ancillary Service providers at any given time. This section provides an en example of a possible framework to select ancillary service providers – in effect the framework for support software or processes that could be employed. Simpler or more complex frameworks may be appropriate initially and over time. In principle the selection process should account for enablement costs, any SSASB and the resultant Balancing costs and may for example see more expensive Ancillary Services selected to allow cheaper Balancing at an overall lower cost than selecting Ancillary Service only on the enablement cost for Ancillary Service.

Ideally, selections would be based on a full co-optimisation analysis of Balancing and Ancillary Services. A move to full co-optimisation would be a complexity not warranted at such an early stage of an Ancillary Service market. As such approximate or rules based approaches will be needed (Note: the design allows for future development of a more complex selection criteria if needed).

Subject to further refinement before operation under new rules commences, the initial selection procedure will involve:

- A LFAS merit order established by System Management [4] times per day and as appropriate at the discretion of System Management following material changes in operating conditions; and
- The LFAS merit order to be based on minimising the cost of LFAS enablement payment and estimates of the average constrained on/off payments for any SSASB for the relevant period the merit order applies for (e.g. 6 hours). Enablement payments will be specified in Market Participants submissions and constrained on/off payments will be the difference between the market Balancing price and the price for Balancing submitted by the Market Participant. Initially the LFAS merit order will not normally be reviewed in the event of Balancing resubmissions other than at the [4] specified review times.

The procedure recognises that if all Resource Plans and demand forecasts are accurate and system frequency is steady at 50Hz then no Balancing and no LFAS will be dispatched. In this circumstance if no pre loading is required Balancing costs will be zero and unaffected by enablement of facilities to provide LFAS. The only cost relevant to selecting which Facility to provide LFAS will be the LFAS enablement charge.

In the case where a Facility can only provide LFAS if it is pre loaded to a SSASB, the BMO will be adjusted (see Box 5). The LFAS provider will then be entitled to receive a constrained on/off payment and different sources of Balancing will be required. The procedure requires an estimate of the average constrained on/off payment which will be based on the forecast average Balancing price (from the amended BMO). The use of average prices over a number of hours, the normal fluctuations in demand and intermittent generation as well as changes to Balancing submissions will mean that the Balancing price in this calculation will often differ from the final price meaning that there is a risk that when assessed after-the-fact the order in which LFAS was called will be inefficient. Monitoring of the market should include an assessment of the level of inefficiency as one factor in considering the benefit of refinement of the procedure.

Additionally there will be a mechanism within the Market Rules that will require selection to be on the most efficient basis that is practicable in accordance with available decision support tools and a procedure to be developed by the IMO. The selection methodology can be reviewed periodically (potentially each 6 months in consultation with Market Participants). This approach will establish the principle in the Market Rules but allow progressive improvement on a procedural basis

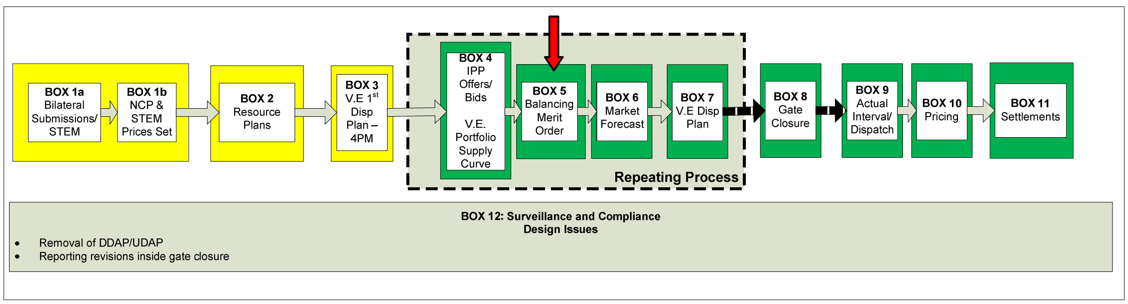
Verve standalone Facilities:

Verve energy will have the ability to elect to submit a "standalone" Facility basis on a trial basis for one month prior to formal removal from the portfolio. Verve Energy will be required to seek System Management (or IMO?) approval for standalone status of a facility at least 1 week prior to the facility being split out on either a trial or permanent basis.

3.5 BALANCING MERIT ORDER (Box 5)

3.5.1 Purpose:

This section explains how the Balancing Merit Order described above will be constructed.



3.5.2 Proposal:

- A market BMO and a Real Time BMO (RTBMO) will be developed. The market BMO will be based on submissions made prior to a defined period before trading the relevant interval (e.g. Facility gate closure). At that time, the Market BMO will become the RTBMO. The RTBMO will continue to be updated as circumstances change and submissions need to be updated (for example, due to a Facility failure) and will be used by System Management for dispatch. Pricing will be based on the final Real Time BMO for each trading interval.

- The BMO for each trading interval will be created by inserting Facility Balancing submission quantities (IPP or standalone Verve facilities) into the Verve Portfolio Supply Curve (Portfolio Supply Curve) in price order. For Facility offers/ bids, maximum Facility ramp up and down rates will also be identified in the BMO.

- Unscheduled / intermittent generation will be included in the BMO based on respective Balancing price submissions and forecast Facility quantities. Inclusion in the RTBMO will be based on their Balancing price submissions and the prevailing capability, which will be available for dispatch by System Management.

- The BMO/RTBMO may also incorporate curtailable, dispatchable and interruptible load so that they can be dispatched downwards in accordance with Balancing price submissions.

- Offers or bids with identical prices will be identified/linked in the BMO/ RTBMO. Their treatment in forecasting and dispatch is discussed later.

- Note that it will not be practical to identify Verve liquids facilities specifically within the BMO/RTBMO unless Verve submits them for Balancing on a Facility basis. i.e. quantity/price pairs within Verve's Portfolio Supply Curve are not linked to individual facilities. Discussed further in relation to dispatch.

3.5.3 Further work:

- Review impact on mechanics of Intermittent Loads in the BMO.

- Incorporating curtailable, dispatchable and interruptible load into the BMO.

3.5.4 Example:

Consider the following (stylised) scenario with Verve and 2 IPP facilities. For now it is assumed that Verve submits a Portfolio Supply Curve for its entire portfolio (i.e. Verve does not present any standalone Facility based submissions). It is also assumed that there is no curtailable load or unscheduled/ intermittent generation.

Verve Submission		
Tranche	**MW**	**$/MWh**
14	50	$420
13	400	$276
12	200	$60
11	80	$40
10	300	$35
9	60	$30
8	20	$25
7	20	$5
6	100	$0
5	40	-$3
4	80	-$5
3	150	-$30
2	200	-$50
1	360	-$275
Tot Capacity	2,060	

IPP1 Facility Submission (Resource Plan = 50 MW[1])		
Parameter	**MW**	**$/MWh**
Up 1	10	$50
Down 1	15	$10
Down 2	25	-$275
Total Capacity	50	
	MW/min up	**MW/min down**
Max Facility ramp rate	2	2

IPP1 submitted a Balancing bid for some of the capacity below its Resource Plan at a very low price. That capacity would not be dispatched down and/or off unless System Management has no other options available within the RTBMO for normal Balancing purposes, creating an overall security of supply situation, or has to dispatch the Facility down for a localised security of supply situation.

[1] Resource plans will be in the form of ramp rate and MW target as discussed earlier (Box 2). This is ignored here for simplicity but will need to be taken into account in forming dispatch instructions (Box 9). For example, if a Balancing offer is to be dispatched and the Facility will already be ramping in accordance with its Resource Plan.

IPP2 Facility Submission (Resource Plan = 100 MW[2])		
Parameter	**MW**	**$/MWh**
Up 1	50	$70
Down 1	50	$30
Down 2	50	-$275
Total Capacity	150	
	MW/min up	**MW/min down**
Max Facility ramp rate	3	3

Also assume that a wind farm has bid in to be dispatched down for negative $40 per MW and the participant has forecast that the Facility will be operating at 50 MW for the duration of the interval.

Submissions would be aggregated into a market BMO for System Management purposes along the following lines. (In practice, the BMO would also identify any identically priced offers and for Facility submissions maximum ramp up and down rates).

	Tranche MW Range		Cumulative MW Range[3]	
ID	**From**	**To**	**From**	**To**
VE PSC	1,610	2,060	1,760	2,210
IPP2	100	150	1,710	1,760
VE PSC	1,410	1,610	1,510	1,710
IPP1	40	50	1,500	1,510
VE PSC	1,030	1,410	1,120	1,500
IPP2	50	100	1,070	1,120
VE PSC	950	1,030	990	1,070
IPP1	25	40	975	990
VE PSC	560	950	585	975
Wind1 Down	50	0	635	585
VE PSC	360	560	435	635
VE PSC	0	360	75	435
IPP2	0	50	25	75
IPP1	0	25	0	25

Information in resubmissions would be used to update the BMO and the RTBMO. Accepted Ancillary Service offers that require pre loading away from Resource Plan in the case of

[2] Resource plans will be in the form of ramp rate and MW target as discussed earlier. This is ignored here for simplicity but will need to be accounted for in formulating dispatch instructions.

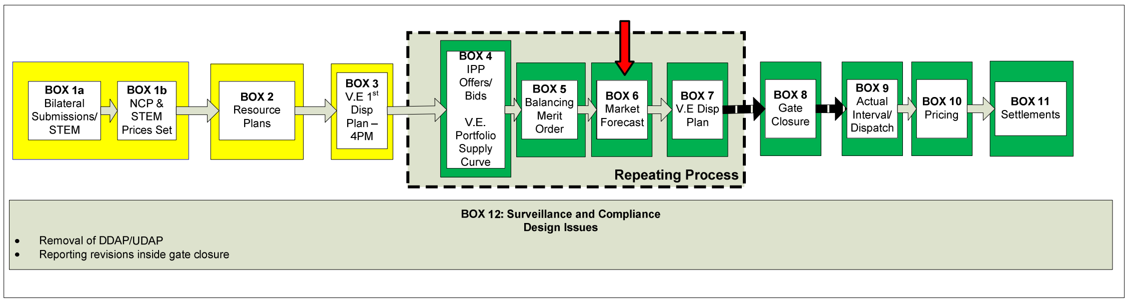
[3] Aggregate MW range added.

IPPs or Verve where a defined MW quantity is required will be reflected in the BMO as appropriate – for example where partial loading is required on a Facility that would not otherwise be operating would be seen as an increase in the capacity at the bottom of the BMO/RTBMO. Similarly if acceptance of an Ancillary Service offer that was conditionally linked to Balancing and will reduce the amount available for Balancing then the capacity at the bottom of the BMO/RTBMO will increase and the relevant Balancing tranche decrease.

3.6 MARKET FORECAST (Box 6)

3.6.1 Purpose:

This section describes the market forecasts that are envisaged.



3.6.2 Proposal:

- Market Participants will be provided with regular 2 hourly (rolling) forecasts of the Balancing price and also their expected Balancing quantity to help them to make informed bids and offers, and prepare for any likely dispatch. Forecasts will extend over the period for which Balancing submissions apply. i.e. forecasts issued today before initial bids and offers for the following trading are due (say prior to 4pm) will cover trading intervals out to 8am tomorrow. Forecasts issued after that time, will cover trading intervals out to 8am the day after.

- The forecasts are especially important in relation to Market Participants decisions about commitment, de-commitment and management of constrained fuel supplies etc and resubmissions to give effect to these decisions.

- It is proposed that the following forecasts will be provided at regular intervals leading into gate closure:

    - Expected system generation requirement (to all Market Participants);

    - Expected overall Balancing quantity (to all Market Participants);

    - Expected overall wind/ non scheduled load and curtailment (to all Market Participants)

    - Expected Balancing price (to all Market Participants);

    - Expected balancing price if total generation requirements are +/- 1% from forecast; and

    - Expected Facility Balancing quantities (to relevant Market Participant only) including identification of any security constrained requirements.

- From the market BMO and forecast total generation requirements, taking account of forecast unscheduled generation, a market forecasting model will determine expected dispatch quantities for facilities (IPP and Verve standalone) and Verve's portfolio and expected Balancing prices.

- The initial forecasts for a trading day will effectively be a system generation schedule covering the rest of the current trading day out to the end of the following trading day. System Management will review this information and advise the IMO of any constraints that need to be applied to generation within the schedule (for example due to a local transmission outage/ constraint). The IMO will incorporate this information into subsequent forecasts.

- System Management will use forecast dispatch quantities for Verve's Portfolio Supply Curve and IPPs (Resource Plans +/- expected dispatch of Balancing offers/ bids) in preparing and updating the Verve dispatch plan.

- The above procedure will continue to be carried out each time a bid/offer is updated by an IPP (or Verve Portfolio Supply Curve updates are allowed) with new forecasts being provided to market at regular intervals. It may also be practical to re-issue forecasts whenever there is a change to input forecasts.

- Forecasts will continue to be provided after gate closure so that IPPs can be prepared for any likely Dispatch Instructions which they might receive.

- The adequacy of the forecasts will need to be reviewed after an initial period of time (it is proposed two years). This review will need to assess the accuracy and also the usefulness to MPs.

Appendix A includes an overview of the above processes.

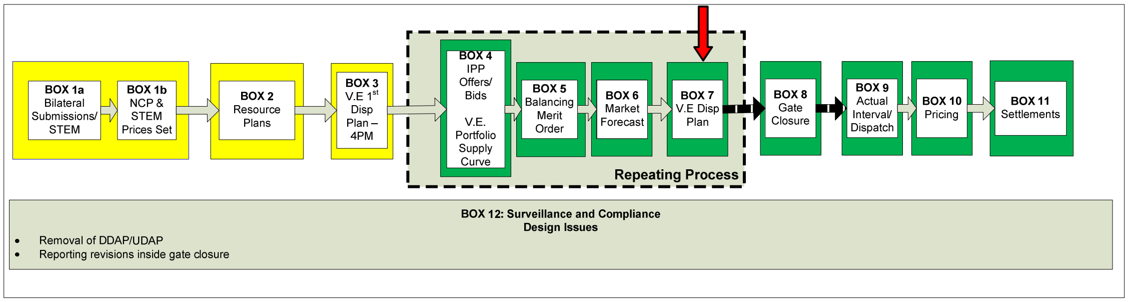
3.6.3 Further Work:

- Discussion with System Management re new systems it may require to support forecasting processes. e.g. more real time load forecasting and/or wind forecasting tools?

3.7 VERVE ENERGY DISPATCH PLAN (Box 7)

3.7.1 Purpose:

This section explains the ongoing need for System Management to re-calculate the Verve Energy DP over the scheduling day to account for forecasted IPP Balancing Bids/offers.

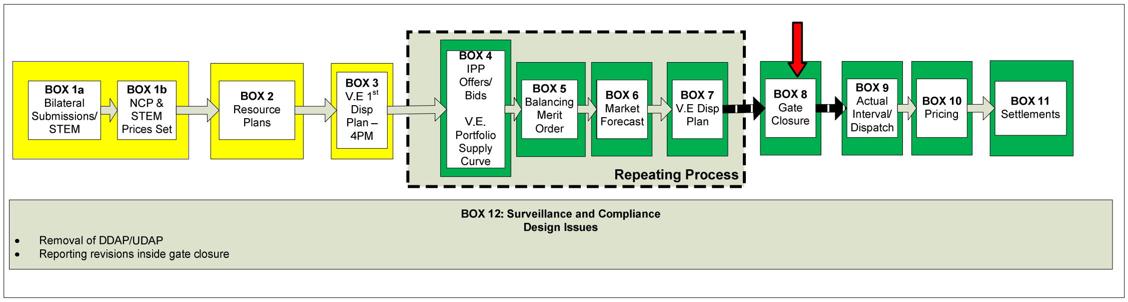


The Verve dispatch plan is prepared by System Management as a service to Verve within the hybrid design and reviewed as needed. In updating the Verve dispatch plan, System Management is in effect undertaking a review and revisions to Balancing bids/offers for facilities within the Verve Portfolio Supply Curve leading up to resubmissions (subject to Portfolio Supply Curve gate closure).

3.8 GATE CLOSURE (Box 8)

3.8.1 Purpose:

This section explains gate closure or the time up to which Market Participants may resubmit specified market information and offers/bids.



3.8.2 Proposal:

- At fixed gate closure times and/ or when a major change in circumstances occurs, such as a Facility failure or having to switch a Facility from gas to liquids Verve may update its portfolio supply curve.

- Up to a normal rolling gate closure, say 2 hours, ahead of dispatch intervals IPPs (and Verve for standalone facilities) may resubmit Facility bids and offers for Balancing/Ancillary Services relative to their Resource Plan.

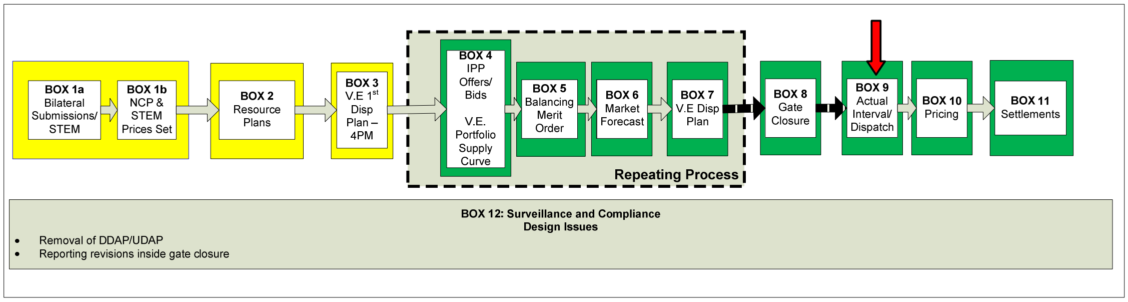
- Normal Facility gate closure requirements may be relaxed if System Management issues a system security advisory indicating a supply shortfall forecast or a supply excess forecast. In these cases Market Participants would be able to increase their offered quantities inside the normal gate closure period in response to a System Management supply shortfall advisory. Market Participants would be able to increase bid quantities (e.g. to effect a de-commitment) within the normal gate closure if System Management has issued a supply excess advisory notice.

- Once normal gate closure has occurred, changes to the BMO/RTBMO will still be required (e.g. for bona fide physical changes to offers/ bids, responses to security advisories, actual wind generation levels etc). The RTBMO used by System Management for dispatch will be the final BMO for pricing purposes.

3.9 ACTUAL INTERVAL/DISPATCH (Box 9)

3.9.1 Purpose:

This section explains how the Balancing market structures outlined above would be implemented. It will explain Dispatch Instructions leading into a half hour period, real time management of load over the half hour and the role of LFAS within the new Balancing Market.



3.9.2 Background:

Instantaneous supply must match instantaneous demand using production under Resource Plans, non-scheduled generation, Balancing service and Ancillary Services.

The Balancing service follows the expected trend during the half hourly dispatch interval in the difference between Resource Plans and the net of total demand, non scheduled resources and steady state requirements of plant providing Ancillary Services[4]. The load following Ancillary Service tracks the instantaneous difference between demand, including losses, and all other production. This principle is unchanged from the status quo.

Instructions to deliver Balancing (Balancing dispatch instructions or Balancing DIs) will be formulated just prior to the start of each half hour in accordance with the RTBMO to ramp to specified MW targets at specified ramp rates at (or from) a specified time within the interval.

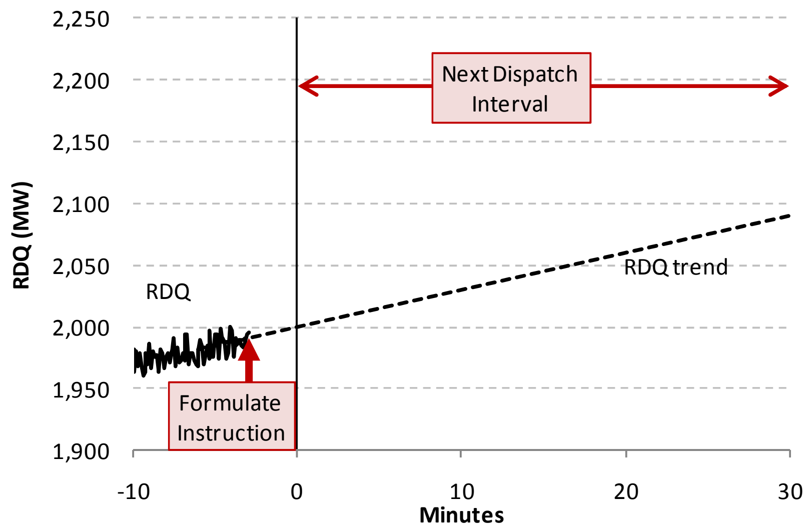
The primary objective of dispatch is to maintain security and minimise the cost of dispatch.

3.9.3 Proposal:

- System Management will use the RTBMO to formulate Balancing DIs.
- If the facilities providing LFAS are to change, relevant LFAS providers would be instructed to enable/disable the service and System Management would bring the relevant facilities into/out of the AGC system.
- Prior to a dispatch interval, System Management will estimate the underlying MW trend in total generation requirements during the next dispatch interval.
    - o This quantity is called Relevant Dispatch Quantity (RDQ) for the remainder of this paper.

---

[4] See previous discussion on requirements to provide Ancillary Services.



- System Management will formulate Balancing DIs in accordance with the RTBMO so as to meet the expected RDQ with the objective of minimising the cost of dispatch. System Management will need to develop systems to formulate Balancing DIs. Where a Facility is selected for LFAS, AGC capability will be required and any conjoint Balancing DI would be issued via AGC. For facilities not selected for LFAS, systems will be required for System Management to issue and for Market Participants to receive Balancing Dispatch Instructions.

- System Management will have overriding authority to intervene in order to maintain security but will be expected to follow market based processes where feasible.

- System Management would continue to monitor security and Facility responses to Balancing dispatch instructions during an interval and would issue new instructions if required.

Format of Dispatch Instructions:

- A Balancing DI is an instruction to a Facility to change output:

  - For an IPP or Verve standalone Facility, an instruction is relative to RP (assumed to be zero if no Resource Plan submitted).

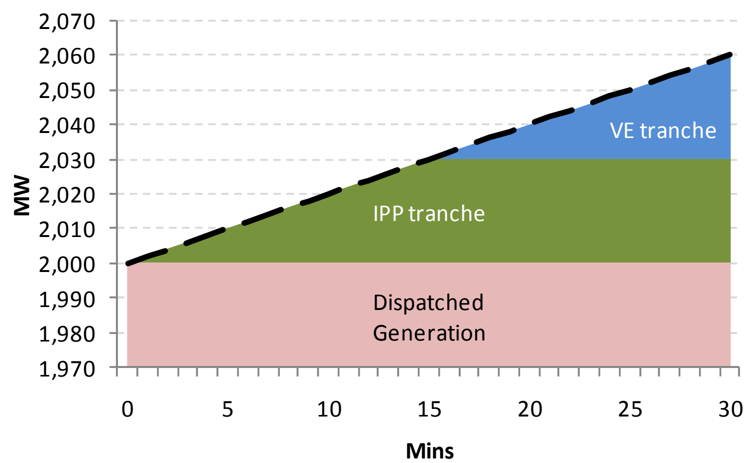
  - For Verve's portfolio, System Management will issue instructions to facilities to adjust their gross output so that the portfolio is dispatched to meet RTBMO requirements.

- A Balancing DI is an instruction to change output once and in one direction:

  - System Management will typically issue one only ramp rate and MW target to a Facility just before a trading interval (with LFAS compensating for residual imbalances within the trading interval).

  - If necessary, System Management may need to issue new instructions within a trading interval (for example, to maintain LFAS services within their offered MW regulation ranges or to address unexpected system events within a dispatch interval).

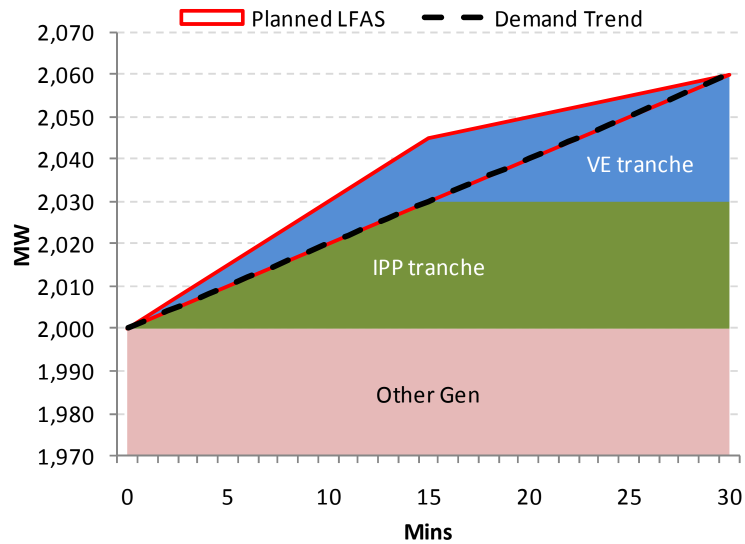
- Subject to the above, Balancing DIs will typically be issued prior to an interval and consist of:
    - o A MW target;
    - o A ramp rate (less than or equal to specified maximum Facility ramp up/down rates); and
    - o A time to start ramping (to distinguish clearly between the Balancing and LFAS roles, under normal circumstances this time will be no later than say 15 minutes (to be confirmed) into the interval).
- These concepts are illustrated below:



- In the example shown, an IPP Facility Balancing offer is able to be dispatched at less than its specified maximum ramping rate to follow the expected trend in RDQ (the dashed line). This minimises the use of the higher priced Verve tranche.

Planned LFAS:

- A consequence of the above methodology is that where it is necessary to dispatch multiple offer/ bid tranches in a dispatch interval, they could be instructed to ramp up linearly to an end of interval target as illustrated below.
- As illustrated, this implies a certain level of LFAS is in effect planned (aside from variations from trend) during dispatch intervals – which is called “planned LFAS” in the remainder of the paper.



Practical dispatch considerations:

- It is important to recognise that Balancing DIs will be based on market parameters which do not account for all factors that affect operation of a generating Facility within a half hour. For example; to reflect automatic governor response to system frequency changes; having to put equipment in/out of service while ramping (such as coal mills, feed pumps etc); block loading/ ramping/ hold requirements when bringing a Facility into service etc; or Facility problems/ delayed start-ups etc. As a result Balancing DIs are incapable of defining sub half hour production requirements precisely. Dispatch via AGC will reduce some of the sources of imprecision but not all and is not mandatory in order for a Facility to contribute to Balancing.

- To the extent practical, offers/ bids should take all relevant factors into account (being reasonable estimates of the capability of a Facility if dispatched) and Market Participants will be expected to follow instructions to the extent practical. Consistent and material deviations from instructions developed in accordance with bids/offers would be a compliance matter. Deviations from instructed DIs are to some extent inevitable and need to be viewed in the context that half hourly dispatch in any event is inherently imprecise, being based on estimates of trends in demand and intermittent supply during a dispatch interval, and made prior to the interval.

  While System Management is entitled to rely on instructions being implemented in accordance with offers through the market over a half hour, Market Participants will also be required to inform System Management of all relevant limitations on response to DIs. This will enable System Management to determine dispatch of Balancing and Ancillary Services across the power system as a whole.

Outstanding issues:

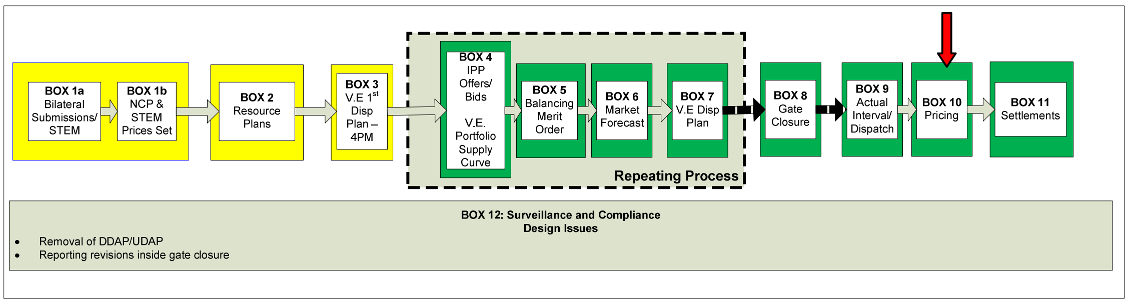
- As noted above, System Management will require decision support software that incorporates the above rules with the total generation forecasts and the RTBMO. For example, to manage the potential of multiple tranches being dispatched in an interval, including one ramping down while another ramps up, to help determine the appropriate start times, targets and ramp rates for Facility instructions (taking into account Resource Plans where a Facility is already ramping to a MW target during the interval).

- Verve liquid facilities: Verve will be able to separate dual fuelled facilities from its portfolio submission, with associated resubmission flexibility up to gate closure. Verve will also be able to update Facility submissions if a material change in circumstances criterion is met (need to define). The alternative of requiring System Management to dispatch IPP submissions ahead of Verve liquid facilities (as now) and adjusting the RTBMO could be considered further but is problematic given that the Verve Portfolio Supply Curve is not Facility specific.

3.10 PRICING (Box 10)

3.10.1 Purpose:

This section describes the calculation of prices within the short term operation of the WEM



Balancing Price:

Objective: balancing price to reflect the marginal price of resources dispatched by System Management to provide actual balancing from IPP and any Verve facility prices and Verve PSC prices.

3.10.2 Proposal:

- The balancing price is to be calculated ex post from the Energy Relevant Dispatch Quantity (ERDQ) and RTBMO for the half hour trading interval, based on actual MW (SCADA) levels for facilities and the Verve portfolio at the start of each interval and maximum facility ramp rates.

- Constrained on/off payments will be made to participants dispatched by System Management where the price of the bid or offer dispatched is inconsistent with the balancing price. This is discussed under Settlements.

3.10.3 Details:

- The ERDQ is the total amount of energy generated ('sent out') by facilities in the trading interval. This will need to be calculated using SCADA given delays in obtaining metering data and lack of metering at Verve facilities. Ideally the ERDQ would be calculated by averaging SCADA readings across the trading interval. Alternatively, end of period readings for the current and previous intervals could be averaged.

- The methodology involves calculating the amounts of energy that could have been generated in merit order from each tranche in the RTBMO, and in the case of unscheduled supply what was actually generated, to satisfy the ERDQ.

- The balancing price will be set the day following the trading day at the price of the marginal tranche in the above calculation.

Example:

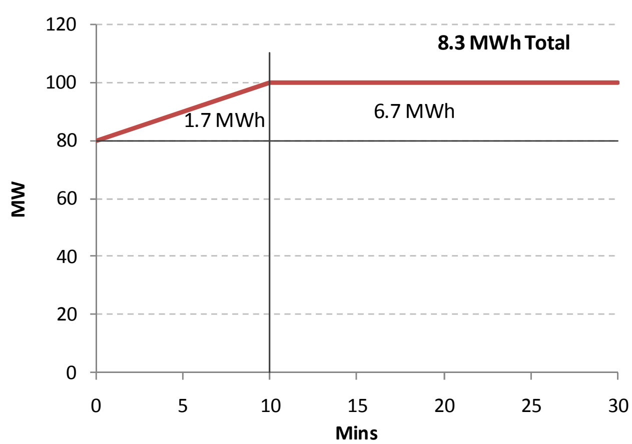
Basic

- For each facility based tranche in the RTBMO, the maximum and minimum amounts of energy that could have been dispatched in the interval will be calculated. This will take into account the amount of generation from the relevant facility at the start of the trading interval and the maximum ramping rate of the facility.

- For example, consider a 100 MW facility that is operating at its resource plan level of 80 MW at the start of an interval. Suppose the balancing submissions for that facility were as follows:

Facility Submission (Resource Plan = 80 MW flat)		
Parameter	**MW**	**$/MWh**
Offer (Up) 1	20	$50
Bid (Down 1)	80	-$275
Total Capacity	100	
	MW/min up	**MW/min down**
Max facility ramp rate	2	5

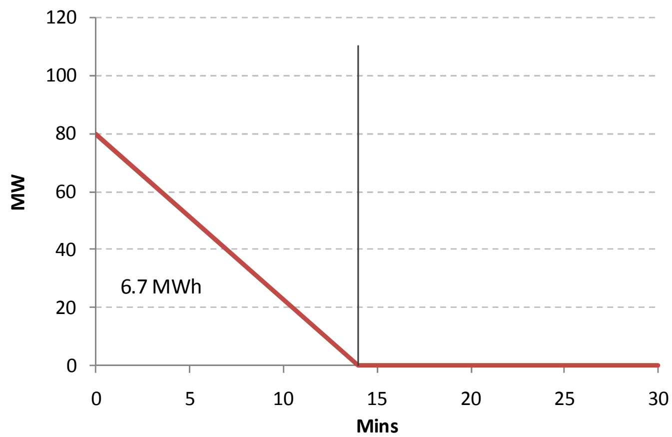
- The maximum amount of energy that the facility could be instructed to generate from the $50 per MWh tranche would be 8.3 MWh as illustrated below:



- The minimum amount of energy that the facility could be instructed to generate from the $50 per MWh would be zero (i.e. if the facility did not need to be dispatched off its resource plan).

- The maximum amount of additional energy that the facility could be instructed to generate from the tranche at negative $275 per MWh would be 40 MWh (i.e. if the facility did not need to be dispatched off its resource plan level).

- The minimum amount of energy that the facility could be instructed to generate at negative $275 per MWh would be 6.7 MWh as depicted below.



- These calculations would be carried out for each facility based tranche in the RTBMO.

- For each Verve portfolio tranche, the maximum and minimum amounts of energy that could have been dispatched would be the maximum quantity offered and zero (no ramp rate constraints).

- The dispatchable quantities would then be sorted in price order (as in the RTBMO) to establish the balancing price with reference to the ERDQ. For example, as in the stylised example below. If the ERDQ was anywhere between 540 and 548.3 MWh, the balancing price would be $50 per MWh (set by the shaded IPP offer 1).

				Cumulative MWh	
Tranche	Min MWh	Max MWh	$/MWh	From	To
VEPSC3	0	200	$275	548.3	748.3
IPP offer 1	0	8.3	$50	540.0	548.3
VEPSC2	0	300	$40	240.0	540.0
VEPSC1	0	200	-$50	40.0	240.0
IPP bid 1	6.7	40.0	-$275	6.7	40.0

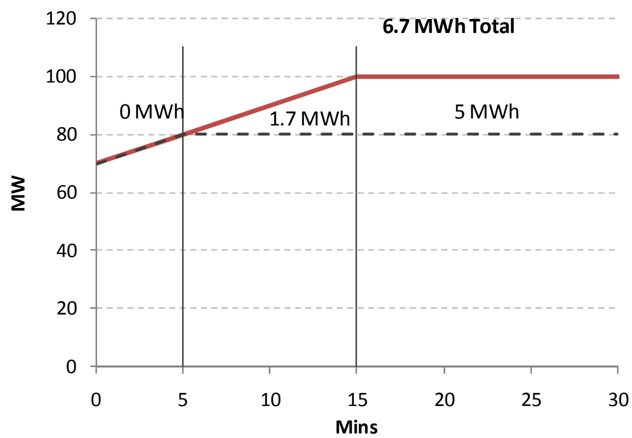
Accounting for ramping within resource plans

- In the above example, the IPP is operating at the resource plan level at the start of the interval and has a fixed resource plan throughout the interval (i.e. no change in resource plan level (NCP / own load) from the previous interval).

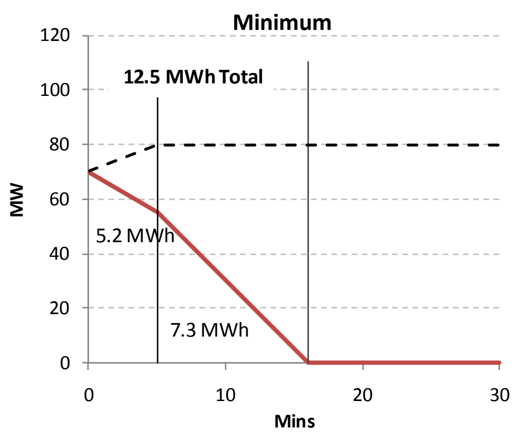
- In practice, the facility's resource plan may include ramping to a new level (refer box 2). For example, assume that in the above scenario, the facility is operating at a resource plan level of 70 MW at the start of the interval and that the resource plan ramps up to 80 MW[5] at 2 MW per minute. As illustrated below, the maximum energy

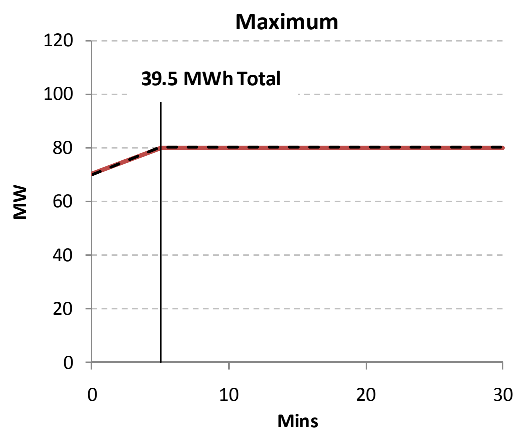
5 e.g. 40 MWh NCP.

that could be dispatched from the IPP offer 1 tranche is 6.7 MWh. As before, the minimum is zero (if it does not need to be dispatched off resource – the black dashed line).



- For the IPP bid 1 tranche, as illustrated below, the minimum and maximum amounts of energy able to be dispatched in the interval are 12.5 MWh and 39.5 MWh respectively.





- The dispatchable energy for IPP offer 1 and IPP bid 2 tranches in the pricing table would then be as follows (changes from the previous table shaded):

				Cum MWh	
Tranche	Min MWh	Max MWh	$/MWh	From	To
VEPSC3	0	200	$275	546.3	746.3
IPP offer 1	0	6.7	$50	539.6	546.3
VEPSC2	0	300	$40	239.6	539.6
VEPSC1	0	200	-$50	39.6	239.6
IPP bid 1	12.5	39.6	-$275	12.5	39.6

Unscheduled generation

- Suppose the above example is extended to include an unscheduled generation facility. Its actual energy production for the interval would be inserted into the above table at the bid price in its balancing submission. For example, suppose a wind farm had submitted a balancing submission of negative $40 per MWh (refer examples in box 5). If the wind farm actually produced 30 MWh during the interval, the above table would be as follows:

Tranche	Min MWh	Max MWh	$/MWh	Cum MWh From	Cum MWh To
VEPSC3	0	200	$275	576.3	776.3
IPP offer 1	0	6.7	$50	570	576.3
VEPSC2	0	300	$40	270	570
Windfarm	0	30	-$40	240	270
VEPSC1	0	200	-$50	40	240
IPP bid 1	12.5	39.6	-$275	12.5	40

Constrained on/off

Constrained on/off payments will be made to participants dispatched by System Management where the price of the bid or offer dispatched is inconsistent with the balancing price. This is discussed under Settlements.

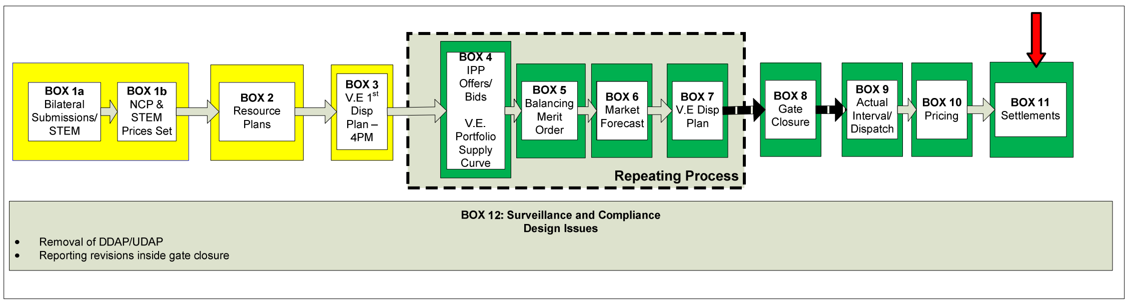
3.10.4 Further work:

The inclusion of load curtailment in the ERDQ.

3.11 SETTLEMENTS (Box 11)

3.11.1 Purpose:

This section describes the primary settlement transactions.



In principle settlement transactions are unchanged from the current market in that

Parties providing Balancing up are paid the Balancing price and parties Balancing down pay the Balancing price.

New transactions are to be created in relation to constrained on/off payments where payments at the Balancing price are inconsistent with participant offers. (For system security constrained on/off situations, the net result will effectively be the same under the current pay as bid constrained on/off regime).

Principle:

- A market transaction will exist whenever metered half hour (hh) dispatch differs from hh NCP (no change).
- A market transaction will have occurred when an IPP Facility or Verve standalone Facility output is increased or decreased from Resource Plan or when Verve's portfolio is dispatched above or below residual NCP (i.e. NCP less any Verve standalone Facility Resource Plans) as a result of:
    - An instruction from System Management for Balancing.
    - An instruction from System Management to load to a specified level, the SSASB, (consistent with the offer from the market participant in order to be capable of providing Ancillary Service (e.g. part loading for LFAS). See also constrained on/off payment).
    - Automatic response from individual plant providing Ancillary Service.
- All market transactions will be paid at the Balancing price.
- Under defined circumstances a constrained on/off payment will also be made (discussed below).
- Parties selected to provide Ancillary Service will also receive an enablement payment in accordance with the design of the particular Ancillary Service.
- Market Participants dispatched by System Management to operate at an SSASB that is different to their Resource Plan will be entitled to be paid a constrained on/off payment (as appropriate) in addition to payment for the market transaction at the Balancing price as noted above.
    - Note: dispatch of energy as part of the delivery of an Ancillary Service around a relevant SSASB will not attract a constrained on/off payment (any cost impacts will be presumed to be reflected in the enablement fee submitted by the Market Participant)
- Windfarms will receive payment for being dispatched down based on difference between actual output and ex-post estimate of actual output possible during the interval

Settlement of constrained on/ off amounts:

Objective: To recompense Market Participants where the price of a Facility Balancing offer or bid dispatched by System Management is inconsistent with the calculated Balancing price.

- A Facility dispatched by System Management above (below) its Resource Plan will pay the market Balancing price for the quantity involved (normal settlement of Balancing amounts). Constrained on or off payments may also be required to compensate for differences between the Balancing price and the price of offers or bid tranches dispatched by System Management.

- For example, suppose the Balancing price is determined to be $15 per MWh. A Market Participant that was dispatched down below its Resource Plan by System Management and had a bid price of $10 per MWh, would have expected to pay that amount, not $15/MWh. So the Market Participant would receive a 'constrained off' compensation payment of $5/MW to compensate for the difference.

- This holds for negative priced bids as well. For example, had the Balancing price been negative $15 per MWh and the Market Participant's bid price negative $20 per MWh, the IPP would have paid negative $15 per MWh (i.e. received $15/MWh) but expected to have paid negative $20 per MWh (i.e. receive $20 per MWh) for the quantity of downwards Balancing it provided. In this instance, compensation would be paid at negative $5 per MWh (the Market Participant would receive $5 per MWh) for the quantity of downwards Balancing it was instructed to provide).

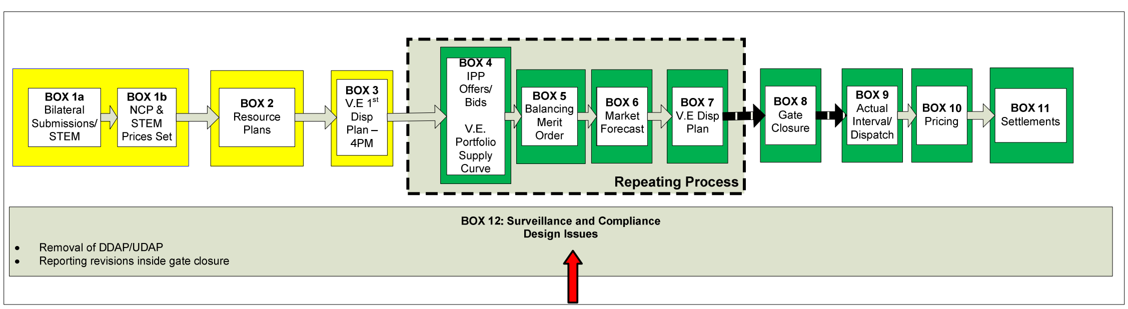
- The constrained off (or on) event may have been because of a system security situation[6] (in effect as now) or (a new requirement) due to approximations that must be made in formulating dispatch instructions to follow expected trends in dispatch intervals and in calculating half hourly Balancing prices ex post.

- Constrained on/off payments will be allocated to Market Customers proportional to their energy use in the interval the payment was made.

3.12 MARKET POWER, SURVEILLANCE AND COMPLIANCE (Box 12)

3.12.1 Purpose:

This section explains the expanded role of surveillance and compliance monitoring in the context of the new competitive Balancing Market.



3.12.2 Background:

---

[6] The WEM currently provides for as bid payments for security constrained dispatch of IPP facilities. Going forward, that will still be the case $Q_{dispatch}$ * PriceAsBid (now) is same as $Q_{dispatch}$ * $Price_{Balancing}$ + $Q_{dispatch}$ * ($Price_{Balancing}$ - $Price_{bid}$)

Market power can have a positive or negative impact on market outcomes. The ability to exercise market power detrimentally to the objective of the market is common in many electricity markets. On the other hand the threat or actual exercise of temporary of market power can be a key incentive for competitors to enter a market or reduce costs. Detrimental market power can be managed by careful design of the market to incentivise participants to bid at SRMC and/or including provisions such as the requirement in the WEM for parties with market power to bid at SRMC, by countering the effects through contracts and also by ex post penalties or threats of penalty.

Monitoring and surveillance of a market can be used to identify both the exercise of market power and compliance with market rules. Compliance with market rules is important for the orderly conduct of an electricity market especially where coordination of operation must occur in very short timescale. Compliance is also important where rules have been designed to manage market power.

This section briefly notes the impact on market power, surveillance and compliance of the package of changes proposed in this document.

- Compliance with formation of Resource Plans given that UDAP and DDAP penalties are proposed to be removed and the requirement is to be relaxed when NCP changes;

- Surveillance of the basis for renominations – given the proposal to allow renominations under some circumstances such as following material change and for bona fide physical reasons specially within gate closure periods;

- Compliance with Balancing instructions;

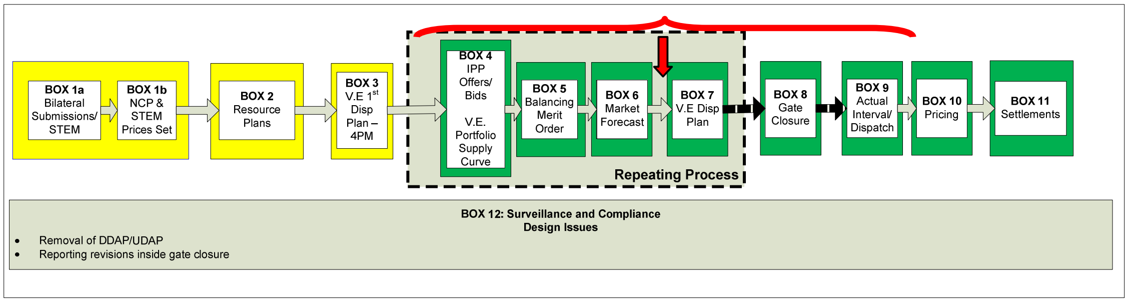
- Compliance with provision of Ancillary Services;

- Level and reason for constrained on/off payments (to assist future development);

- Ancillary service offer prices; and

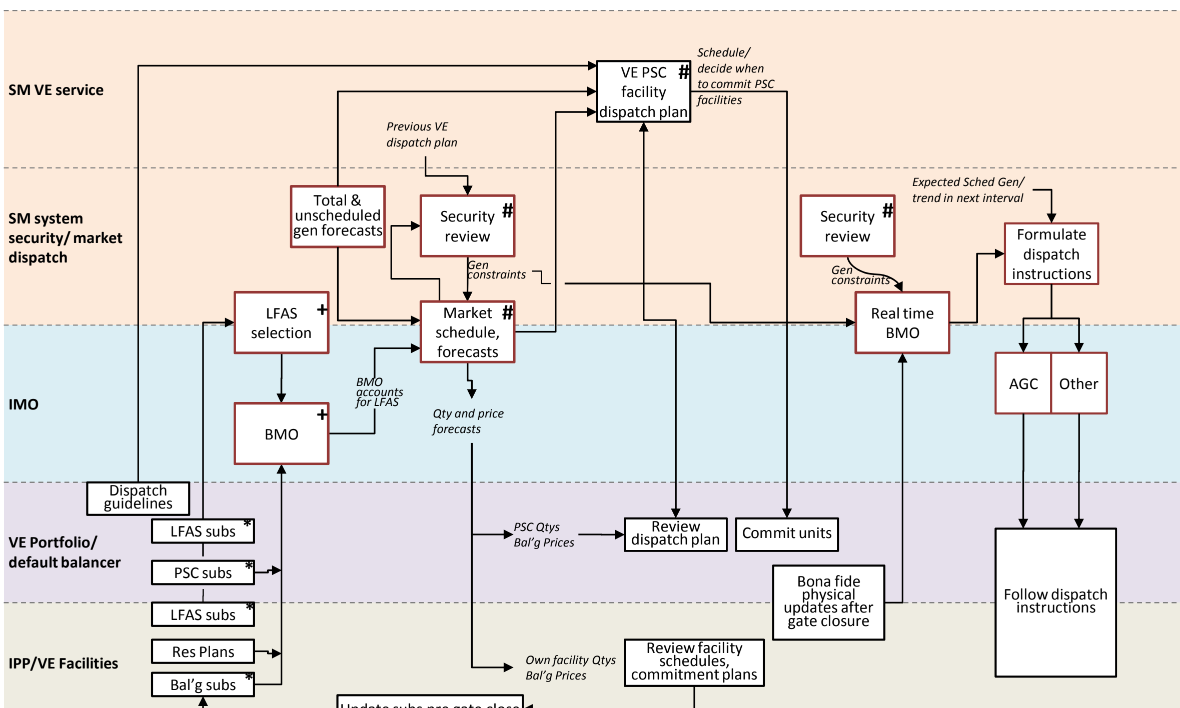
- If appropriate - Operational definition of market power and existing requirement for SRMC prices in bids/offers.

APPENDIX A: PROCESS, ROLES AND RESPONSIBILITIES



The following diagram illustrates the processes (including where process are repeated over the course of a day) and the roles and responsibilities within the proposed design described in the 12 stages.

Overview of Market Processes



Notes:

*
- Can revise pre relevant gate closure
- Otherwise only for bona fide reasons
- Or in response to SM 'security states'

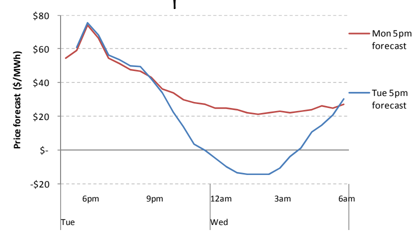
+
- Update when submissions revised and/or regular intervals
- Real time BMO accounts for bona fide changes after gate closure, up to interval

#
- Ongoing and as required

APPENDIX B: OVERNIGHT EXAMPLE

Overnight example

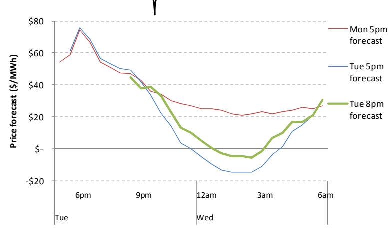
- Initial 5pm market forecast (scheduling day) indicates overnight prices of around $20/MWh
    - Issued 30+ hours ahead of overnight intervals
    - Issued several hours after NCPs established, resource plans submitted
- 5 pm forecast (trading day) indicates lower overnight prices
    - e.g. lower demand/ higher wind than forecast 24 hours beforehand
    - 7-8 hours before overnight intervals*

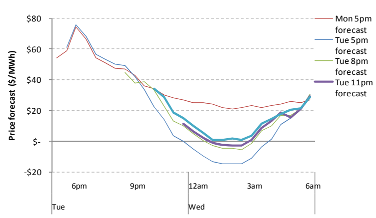


* *Had intermediate price forecasts indicated this trend, participants could have responded earlier given flexibility to revise facility submissions*

Overnight example *(cont'd)*

- A MP may consider it worth decommitting a facility and submit a bid that would do so (e.g. low –ve price)
- Reflected in later 8pm market forecast
- If de-commitment opportunity seen as worthwhile (taking start up into account etc), leave bid at gate closure
- If gate closure 2 hours out, could also leave decision until 11 pm





APPENDIX C: GLOSSARY

Appendix 4 – Sapere: Cost Benefit Analysis

sapere research group

Introducing Competition to Balancing Services

A high level cost-benefit analysis

Kieran Murray

April 2011

About Sapere Research Group Limited

Sapere Research Group is one of the largest expert consulting firms in Australasia and a leader in provision of independent economic, forensic accounting and public policy services. Sapere provides independent expert testimony, strategic advisory services, data analytics and other advice to Australasia's private sector corporate clients, major law firms, government agencies, and regulatory bodies.

Wellington
Level 9, 1 Willeston St
PO Box 587
Wellington 6140
Ph: +64 4 915 7590
Fax: +64 4 915 7596

Auckland
Level 17, 3-5 Albert St
PO Box 2475
Auckland 1140
Ph: +64 9 913 6240
Fax: +64 9 913 6241

Sydney
Level 14, 68 Pitt St
GPO Box 220
NSW 2001
Ph: + 61 2 9234 0200
Fax : + 61 2 9234 0201

Canberra
Level 6, 39 London Circuit
PO Box 266
Canberra City
ACT 2601
Ph: +61 2 6263 5941
Fax: +61 2 6230 5269

Melbourne
Level 2, 65 Southbank Boulevard
GPO Box 3179
Melbourne, VIC 3001
Ph: + 61 3 9626 4333
Fax: + 61 3 9626 4231

For information on this report please contact:

Name: Kieran Murray

Telephone: +64 4 915 7592

Mobile: +64 (0)21 245 1061

Email: KMurray@srgexpert.com

Executive Summary

This report summarises our assessment of the costs and benefits of a proposal to introduce competition into the provision of balancing services in the South West Interconnected System Wholesale Electricity Market (WEM). The results of this study are intended to inform a decision by the Rules Development Implementation Working Group around whether to proceed with the proposal.

Scope and method of study

The study is focussed on economic effects- changes to the level of real resources available to the economy. Economy-wide effects, as opposed to individual effects on particular parties, are estimated. Factors that do not result in changes to resources (and associated economic welfare), such as price effects and wealth transfers are excluded. The methods employed involved modelling, desk-based analysis and consultation with industry stakeholders.

The analysis supports proceeding with the proposal

We quantified a small number of direct benefits (as opposed to benefits that are indirect or more diffuse or less sure) and compared these benefits with the costs of the proposal. This analysis shows that the economic welfare of society would be improved as a result of the proposal. That is, the benefits of the proposal outweigh the costs. In present value terms, the net benefits to the economy range from $24.81m in the high (optimistic) scenario, to $ 8.91m in the low (pessimistic) scenario. The ratio of benefits to costs is 2.58 in the high scenario and 1.37 in the low scenario. Doing nothing would mean foregoing the net benefits available from the proposal.

Summary results (to be modified)

	High	Medium	Low
Total benefits	$40.52 m	$35.98 m	$32.97 m
Total costs	$15.72 m	$19.71 m	$24.06 m
Net benefits	$24.81 m	$16.27 m	$8.91 m
Benefit-cost ratio	**2.58**	**1.83**	**1.37**

The positive results are robust to changes in parameters and assumptions

Changes to key parameter values and assumptions did not alter the essential conclusion that benefits outweigh costs. The net benefits associated with the proposal were relatively insensitive to changes in the costs of inputs, a range of additional scenarios around cost and benefit levels, the discount rate used in the analysis and the time period used in the study. Only when the study period was substantially truncated (from a period of seven years to below three) or when the discount rate was multiplied by a factor of seven (from 8% to over 55%) did the proposal result in net disbenefit (i.e. a benefit-cost ratio below one in value).

Some effects not able to be quantified, but still important

The results mentioned relate solely to those effects that we could quantify. There are other effects that are also relevant, but are either not able to be quantified or would not be captured by the timeframe for the study. These effects include incentives to investment, confidence levels, longer-term transitional impacts and price signalling impacts.

Our assessment is that these non-quantifiable effects are as important as the quantifiable impacts. In terms of scale, they may be more significant. The impact of the non-quantifiable effects is to provide further support for the proposal, though we cannot accurately state the magnitude of non-quantifiable benefits.

The proposal is efficiency enhancing and consistent with wider WEM objectives

In summary, we estimate that there are clear efficiency-enhancing effects associated with the proposal in terms of:

- Productive efficiency- least-cost production of electricity.
- Allocative efficiency- resources devoted to generation most suitable for balancing.
- Dynamic efficiency-producing appropriate signals around investment and encouraging innovation.

These effects support the WEM objectives.

Table of Contents

1 Introduction

1.1 Background

In August 2010, the Rules Development Implementation Working Group (RDIWG) was established by the Market Advisory Committee (MAC) of the South West Interconnected System Wholesale Electricity Market (WEM). Recently, the RDIWG agreed to conduct further analysis of a proposal that would open up the provision of balancing to competition in a way that recognises the role of Verve Energy as the default balancer for the time being. The analysis will consider operating impacts and the costs and benefits of the proposal. The work is to be finalised by early May 2011.

1.2 Purpose of report

The major purpose of this report is to provide an assessment of the benefits and costs of allowing market participants in the WEM to provide balancing services in a competitive market for balancing services. We use the assessment technique of cost-benefit analysis (CBA).

CBA is valued by decision-makers as it produces a clear understanding of the resource (economic) costs and benefits of particular proposals (i.e. whether society will be better off from the proposal). In addition, the results of CBAs are readily comparable across a range of policy and industry areas, enabling comparison (and prioritisation) of initiatives in a manner that is consistent and coherent.

1.3 Lessons from CBA of electricity market reforms

Internationally, there has been a substantial amount of restructuring across electricity markets in recent decades and this has been accompanied by a significant amount of research into the costs and benefits of both proposals ex ante, and implemented changes ex post. This is not the appropriate place for a lengthy review of this body of work. However, some high level points may be made.

A useful summary of US electricity industry cost benefit assessments was completed in 2006 by the Electric Energy Market Competition Task Force.[1] This review

[1] The Electric Energy Market Competition Task Force (2006) Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy.

considered thirty individual assessments undertaken between 2000-2005. Some general conclusions were drawn from the review. A number of these conclusions could be viewed as pertinent to the techniques employed in the CBA:

- Assessments often overemphasised the benefits with little discussion of the costs of restructuring proposals.
- Models are gross simplifications of the complexity of the electricity market and make simple and at times misleading assumptions about market behaviour.
- There are often data limitations necessitating assumptions, which can drive the result of the modelling. Sensitivity analysis of assumptions made is important.

Other conclusions warn the user of the results of the analysis against assuming that all the relevant information can be incorporated in this type of analysis:

- Many of the most significant benefits, which are often the motivation for changes, are difficult to quantify and therefore left out of the assessments. Maintaining system reliability and facilitating lowest cost electricity production were highlighted as key amongst these.
- Assessments often do not consider the distribution of costs and benefits across society, whereas in reality this may form an important component of the decision.

The decision criteria therefore should in most cases be broader than the quantified information available from the CBA.

In 2002, a NECA paper assessing the options for capacity mechanisms in the National Electricity Market notes the need for criteria other than the broad efficiency objective in the National Electricity Code to be considered.[2] The assessment criteria adopted for that study included:

- Consistency with market and NEC objectives.
- Effect on participants' risk profiles and prudential requirements.
- Economic efficiency implications.
- Form, extent, incidence and equity of charges and payments.
- Relative merits of market-based solutions versus central intervention.

---

[2] Travis Consulting (August 2002) Capacity Mechanisms: The Options, prepared for NECA. These criteria are drawn from Putnam, Hayes and Bartlett Asia Pacific (1999) Capacity Mechanisms in the National Electricity Market: A discussion paper prepared for NECA.

- Simplicity and transparency.
- Transition arrangements, including the impact on incumbent revenue and expenditure.
- Long-term viability, in particular incentives for future investment.
- Stakeholder confidence in the market.

The Nordic electricity markets were progressively liberalised through the 1990s and are now integrated through Nord Pool at the wholesale level, while progress is ongoing at the retail level. As part of integrating the retail markets, the integration of balancing services is required.[3] A long list of guidelines was suggested for establishing an integrated market. Although this problem is slightly different to that facing Western Australia some of the guidelines may be relevant:

- Balancing service selection should be market oriented and economically efficient, contributing to operational security at least cost.
- Markets should promote effective competition, not create unjustified technical barriers to trade or unnecessary barriers to entry, not aggravate market power and be non-discriminatory.
- Changes to market rules should be made through a clear and transparent process and enforced in a clear manner.
- In order to avoid the misuse of market power incentives should be created by the structure of the market to encourage participation by generation and load.

Our reading of the experience with CBA of electricity market reforms elsewhere is that we must be mindful of the technical details of CBA and that not all of the key motivational factors for market reforms are conducive to quantification through a CBA. We also observe that the vast majority of studies we located were completed after market reforms had been implemented. This suggests that it may be more difficult to apply quantification techniques before reform is implemented because these techniques require the proponents of reform to be specific about the intended changes and expected benefits. The work of the RDIWG is therefore unusually (in a positive sense) rigorous in its approach.

[3] NordREG Towards Harmonised Nordic Balancing Services Common Principles for Cost Allocation and Settlement, Report 3/2008.

1.4 WEM Objectives

The relevant motivating factors for WEM are determined by reference to the objectives established in the Electricity Industry Act 2004:

- To promote economically efficient, safe and reliable production and supply of electricity and related services in the South West inter-connected system (SWIS).
- To encourage competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors.
- To avoid discrimination 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.
- To minimise the long-term cost of electricity supplied to customers from the SWIS.
- To encourage measures to manage the amount of electricity used and when it is used.

It is not possible to achieve these objectives with a single initiative. For example, measures to facilitate entry of new competitors could include establishing regulatory certainty through clear rule change processes, eliminating unnecessary technical requirements, ensuring non-discriminatory access to markets, and enhancing transparency around market operations and pricing. The multi-faceted nature of the solution to such problems should not mean that measures cannot be implemented independently of each other.

In the case of the objective to reduce the long-term cost of electricity supplied to consumers, economists generally accept that opening markets to new participants would reduce long-term costs by introducing competitive pressures around current offering strategies and longer-term investment decisions. To minimise supply costs it is also necessary to maintain a high level of stakeholder confidence in the operation of the market, as risks are priced into decisions by investors. Incremental change is a valid way of maintaining this confidence while progressing toward the desired outcome of an open, competitive market.

A long-term perspective needs to be taken on the evolution of the market toward increasing competition and lowering costs. The introduction of competition for supply of balancing services should be seen in the context of this larger objective and valued as an initial step to this goal, in addition to its own measured net benefit.

1.5 Structure

This report is structured as follows:

- Section 2 describes the proposal in more detail.
- Section 3 outlines the nature of costs and benefits relevant to this analysis
- Section 4 sets out the baseline case against which the costs and benefits will be compared.
- Section 5 details the estimated effects of the balancing market proposal and explains the basis of those estimates, including caveats and assumptions.
- Section 6 discusses the likely net effect of the proposal.
- Section 7 concludes with summary comments and recommendations.

Background material around the analytical approach and its key components is included as an appendix.

2 Proposal under consideration

This section outlines the basic features of the proposal to introduce competition into provision of balancing services. The final design of the market, and indeed whether or not to proceed, is still under consideration. Therefore we describe the features in a somewhat generic manner; refinement will be possible once further details become clear. This section also contains a problem statement which sets out our understanding of the rationale for the proposal.

2.1 Problem statement

The MAC established the RDIWG (involving representatives from across the industry) to assess problems in specified areas and identify solutions. The problems most relevant to this analysis are:[4]

1. There is very limited opportunity for participants other than Verve to participate in providing balancing services and this inevitably means the cost of balancing is higher than it needs to be.
2. Provisions for Balancing Support Contracts have not been effective to date.

[4] See: "Wholesale Electricity Market- Next Steps. Market Evolution Program: Summary" for a full list of the identified problems/issues. Available at: http://www.imowa.com.au/mep-overview

3. The calculation of MCAP (Marginal Cost Administered Price) and the role of UDAP and DDAP (respectively Upward and Downward Deviation Administered Price) mean that balancing prices are not cost reflective and this leads to inefficient incentives for decisions about prices and participation and inequitable financial transfers between participants that compromise the integrity of the WEM.

In addition, there are issues associated with the Short-Term Electricity Market (STEM) in terms of its ability to provide incentives to participate, including a lack of transparency, timing issues and the single pass design, and rigidity of requirements for resource plans to match STEM outcomes. Barriers to participation render the STEM less effective as a means of price discovery. Furthermore, the transparency and cost issues are exacerbated by having a default balancer that does not provide facility-based submissions, meaning delays in the discovery of important prices, and little opportunity to mitigate the effect of those prices.

2.2 Proposal under consideration

In keeping with the current design of the wider wholesale market, a hybrid (simple portfolio/facility) arrangement is suggested for the proposed balancing market.[5]

2.2.1 STEM/ resource plans/ dispatch plan

- The bilateral submissions and STEM process would operate as now.
- IPPs would submit resource plans as now.
- System Management would prepare the initial Verve dispatch plan as now (taking account of resource plans, wind/ demand forecasts and Verve guidelines).
- A balancing price forecast would be prepared using STEM supply curves (assuming all IPPs in the curve and Verve are available for dispatch), resource plans and the latest operational load and wind forecasts. i.e. in effect, treat the participant balancing submissions (described in section 2.2.2) as revised offers following the market forecast.

[5] This description is as set out in the IMO Paper "Balancing Support" dated 23 November 2010. While we understand that detailed design work is still ongoing, the basis of the proposal remains largely the same as outlined in the 23 November paper and this provides the basis for the estimation of costs and benefits.

2.2.2 Balancing submissions

- Late in the afternoon, Market Participants would make balancing price submissions.
- IPP balancing submissions would be by facility:
    - Offers/ bids relative to facility resource plans (or gross offers for a facility not in service)
    - All IPPs would submit balancing prices, with prices reflecting willingness to participate in normal balancing or otherwise.
    - Half-hourly price-quantity submissions would be desirable to maximise flexibility to participate.
- Verve's submission would be by portfolio for each trading interval:
    - Verve would submit its full supply curve (as it does now for its STEM supply curve submission). Initially, the existing STEM submission could be used if that would enable quicker implementation.

2.2.3 Balancing merit order

- The Balancing Merit Order (BMO) would be prepared on a gross basis.

2.2.4 Scheduling and dispatch

- IPPs would operate to resource plans unless dispatched off plan by System Management (as now).
- System Management would schedule Verve facilities as now in accordance with the Verve guidelines (rescheduling if need be to remain within the guidelines, to account for IPPs in the balancing merit order and/ or for system security purposes).
- System Management would use the balancing merit order to the extent practical for dispatch purposes (noting discretion for system security purposes). This would involve:
    - Determining when a balancing dispatch instruction is necessary (e.g. by observing when the frequency regulation/ load approaches limits or is expected to).
    - Monitoring the Verve loss adjusted quantity in real time.
    - Dispatching any IPP quantities (or separately offered Verve facilities) at break points specified in the balancing merit order. IPPs will need to manage constraints extending beyond a trading interval through

their offers and bids rather than expecting inter-temporal trade-offs to be made by the IMO, in preparing the merit order, or System Management, in formulating dispatch instructions.

- Dispatching Verve facilities, in accordance with the Verve guidelines, until an IPP offer or bid break point in the merit order is reached (or a standalone Verve facility). This will at times involve trade-offs in selecting which Verve facilities to dispatch around IPP break points given inter-temporal factors, although similar to the current situation.

2.2.5 Balancing settlements

- System Management would advise the IMO of any IPP quantities it has dispatched (to identify the marginal quantity, establish the marginal price, identify any out of merit dispatch and establish authorised deviations).
- IPPs that were dispatched above their resource plans by System Management (authorised) would receive the marginal balancing price (or out of merit payment if necessary).
- IPPs that were dispatched below their resource plans by System Management (authorised) would pay the marginal balancing price (or an out of merit payment if necessary).
- Verve would be paid/ pay on the same basis for quantities above/ below its NCP.
- IPPs with unauthorised deviations would face the marginal balancing price (i.e. no UDAP/DDAP) for the deviations but be required to provide bona fide reasons for compliance purposes.

3 Taxonomy of costs and benefits

This section sets out the range of costs and benefits considered in this analysis. It is not exhaustive, but rather reflects the practical nature of the undertaking. In relation to benefits, we have focussed on a small number of that have direct effects, as opposed to impacts that are indirect, more diffuse or less sure. On the costs side, there is slightly more certainty, particularly in relation to timing as costs tend to be incurred upfront and generally have a finite life.

Table 1 Taxonomy of major costs and benefits			
Effect	**Components/drivers**	**How expressed**	**Evidence source/strength**
Costs			
Personnel	• Staffing requirements for extended trading periods, additional relationship management and altered duties • Training associated with new arrangements and systems	FTEs/time converted to marginal (additional) expenditure in dollar value terms	Market participants, System Management, IMO.
Systems- assets	• IT requirements to manage in-house trading and forecasting requirements • IT requirements in terms of the interface between participants and IMO	Additional (or re-configured) hardware and software needs converted to marginal (additional) expenditure in dollar value terms	Market participants, System Management, IMO.
Systems- processes	• Monitoring costs (e.g. fuel positions of IPPs; Supervision and awareness costs for System Management (SM)) • Additional preparation of manuals and/or instructions • Associated rule changes • Changes to dispatch costs for default balancer and SM	Additional time costs expressed in net (i.e. total cost minus any offsetting benefits) terms converted to marginal expenditure in dollar value terms	Market participants, System Management, IMO.

Benefits			
Prices	• Removal of DDAP and UDAP and other distortions • IPP tranches lying between relevant quantity and the balanced market position (i.e. MCAP is not cost-reflective)	Impacts on behaviour from the removal of distortions to the balancing price (i.e. what a "clean price" means for balancing)	IMO
Efficiency	• Dispatch of Verve plant for "everyday" balancing requirements when other (IPP) plant could have been dispatched at lower cost • Dispatch of Verve plant for "extreme" balancing requirements when other (IPP) plant could have been dispatched at lower cost. Also, IPPs and retailers face volatility in MCAP – a business risk • Gate closure that is closer to actual trading (i.e. greater plant availability) • Participants can operate plant more efficiently through the balancing market rather than keeping to counter-productive resource plans (i.e. more flexibility)	Resource cost savings from dispatch of less expensive plant in dollar value terms Avoided costs as a result of flexibility.	Market participants, IMO
Investment	• Appropriate signals determine: ○ Nature of investment (i.e. type of plant) best suited to market	Additional investment in dollar terms	Market participants

	situation ○ Quantum of investment (i.e. degree of security/comfort in WEM)	Altered investment New entrants	

3.1 Additional benefits

The table above only contains the effects that are able to be estimated in a quantifiable sense (albeit with some imprecision). There are also a range of other effects that are important, but less amenable to quantification and/or do not result in purely economic outcomes (e.g. financial transfers, which are distributional effects rather than resource costs). These effects are important because they influence behaviour and therefore indirectly affect outcomes that matter. Some of these effects provide softer support for the numbers, in terms of confidence that the proposal will provide a net benefit.

We see the following instrumental benefits arising that have not been quantified.

3.1.1 Transitional advantages

This form of benefit is largely unseen. The benefits arise from the contribution of a competitive balancing market towards preparedness for further WEM evolution. That is, a balancing market provides opportunities for participants to undertake activities that may be beneficial in future. The behaviour changes likely to arise from participation in a balancing market represent a step along the path towards a liberalised and efficient electricity market. In other words, a balancing market provides impetus. The adjustments now may result in avoidance of some of the costs of transition in the future. The proposal is complementary to wider market change objectives and may ultimately pay additional dividends in the future.

3.1.2 Increased confidence

Competitive provision of balancing services may also result in greater confidence levels. Confidence is a necessary, but not sufficient, condition for innovation, which has significant payoffs in the longer term as it is a key driver of dynamic efficiency. The more flexible security processes and automated software that result from the proposal are likely to produce savings that are not immediately quantifiable but that assist in an operational sense. In addition, the central clearing nature inherent in the design of a balancing market should alleviate impediments to participant-to-participant balancing support contracts associated with credit risk, because the IMO will have a prudential role. Participants may also have more confidence about bidding into the STEM knowing that they can resort to a balancing market if their physical situation changes (e.g. if they are forced to buy out of a bad position or if plant is unreliable). While there is a possibility that the proposed balancing market effectively replaces the STEM, it is also possible that they will be complementary in nature. That is, the balancing market results in better all-round operation of the WEM (including the STEM).

3.1.3 Better risk allocation

On the back of increased confidence comes a greater willingness to bear risk. At present the risk-reward calculus is skewed towards safer and more familiar avenues (i.e. bilateral contract arrangements). The enhanced transparency resulting from the proposal may alter those decisions. In discussing the merits of competitive markets for electricity balancing, the European Regulators Group for Electricity and Gas states:

" … transparency concerning market rules, price formation, and market participation will also facilitate the functioning of the market by allowing market parties to make informed decisions and minimise risk concerning investment and operation."[6]

One such decision concerns the choice between renovating existing plant and the purchase of new plant. Where new plant is more amenable to participation in the balancing market and is more efficient in terms of electricity output for given inputs than the existing plant then wider dynamic efficiency benefits accrue from a balancing market than would otherwise be the case, as the market alters these investment decisions in favour of more "balancing capable" capacity. The prospect of stranded costs/assets may also be reduced as result of the balancing market proposal.

3.1.4 Qualitative and long-term benefits swamp short-term effects

The quantifications reported in this study comprise a small number of direct, short-term benefits. In an industry as capital intensive as the electricity sector, the primary benefits of introducing competition into the balancing market will be experienced over the medium to long term due to enhanced incentives. For example, the 30 cost benefit studies of electricity market reforms reviewed in the United States Report to Congress found very large benefits to consumers from increased competition in electricity markets. One study of the PJM market for instance, estimates that the benefits being experienced by residents in that market (which has been operating for sufficient time for competition to have affected investment decisions) amount to a saving of $117 per annum on each residential

6 ERGEG Guidelines of Good Practice for Electricity Balancing Markets Integration, Ref: E05-ESO-06-08 7 June 2006, European Regulators Group for Electricity and Gas. Available at: www.energy-regulators.eu/

electric bill.[7] The future savings, summed and discounted to the present, exceed the total electricity costs for one year.

4 The baseline

To model the benefits of the proposal, we studied the balancing outcomes since 2008, reviewed the papers presented to the RDIWG, and talked to participants about their experiences with balancing. We used the data obtained from these investigations to forecast balancing costs.

Because of some of the distortions involved with the current balancing regime it is difficult to estimate the actual economic costs of balancing at present. Some of those distortions are:

- IPP offers used in determining MCAP.
- Irregularities with the relevant quantity process.
- Verve portfolio-based (rather than facility-based) bidding.

There are a number of ways we can estimate the financial cost of balancing and the economic advantages of opening it up to competition.

Of note is that balancing volumes and overall costs have decreased since 2008. Taking a detailed look at the data reveals several main conclusions:

- First, the supply cushion (or gap between available capacity and actual load) is the main driver of balancing costs. The cushion has widened somewhat between 2008 and the present, which, in turn, has caused balancing costs to decrease.
- Second, while intermittent generation has been a factor in some extreme balancing events, overall it is not a significant causal factor of balancing requirements. At present it is responsible for around 8% of total balancing. That being said, the addition of the Collgar windfarm will increase the contribution of intermittent generation to balancing volumes.

[7] CAEM, Estimating the benefits from restricting electricity markets: an application to the PJM region. http://www.caem.org/website/pdf/PJM.pdf

- Third, there is evidence that, as a result of some legacy gas contracts coming up for renewal, the STEM price is likely to rise over the time period studied. This will, in turn, cause balancing costs to increase.
- Fourth, the IMO's statement of opportunities provides information on how it believes that load will increase over the next years. Contrary to possible expectations, we do not believe that load increases will cause balancing volumes to increase. Load increase will have an effect only through its influence on energy prices.

4.1 Modelling approach

This section sets out the components of, and general approach to the modelling we have undertaken. It contains short descriptions of the process, inputs and reference to assumptions. The overarching principles governing our modelling effort (and the overall project) are as follows.

- *Internal consistency*- avoiding (or minimising) any contradictions or inconsistencies in the assumptions invoked or parameters used (e.g. alignment of factors such as participation rates, timing of costs and benefits and what constitutes an economic impact) as well as checking any conclusions are consistent with the supporting analysis.
- *External validity*- in essence, ensuring the results of the study are able to be understood (i.e. accessible and transparent), accepted and reproduced by outside parties if needed.
- *Efficiency*- rather than reinvent the wheel, we look to build on existing material and look to avoid re-litigating past decisions; sticking to our brief.
- *Objectivity*- we do not bring any strong prior beliefs or positions into the analysis and let the data do as much of the talking as possible, without setting out to find a particular outcome (or set of outcomes).

4.1.1 Process

We have drawn on a number of data sources, studies and meetings with market participants to establish a model to capture the benefits of the balancing proposal. We are interested in how the proposal would lead to a change in the physical dispatch of electricity and the related overall costs, rather than any changes to prices or changes to an individual participant's cost or revenue structure. For that reason, we have not considered the implications of the paper on Balancing Price Formation, which was presented to the RDIWG on 2 November 2011, to the extent that it deals with questions of wealth transfer rather than physical dispatch.

4.1.2 Inputs

We have had access to a wide range of data supplied by the IMO, including SCADA data, and bid and offer data. We have also had available the detailed data on the benefits identified in the paper on Balancing Support presented to the RDIWG on 23 November 2010.

4.1.3 Assumptions

Specific assumptions are set out in detail in the relevant sections that follow.

4.2 Forecasts

We have analysed balancing as it takes place in the WEM. Using data from the beginning of 2007, we have worked out the main drivers of balancing in volume terms and evaluated why MCAP deviates from the STEM price.

DDAP (the downwards deviation administered price) and UDAP (the upwards deviation administered price) do not feature in this analysis. Although these prices are relevant to the extent that they cause penalties to IPPs, they are not incurred by all participants who deviate from plans and are therefore an unnecessary complication.

Time periods are defined as the year to 30 September, consistent with the Statement of Opportunities. So, 2007/08 is the year from 1 October 2007 to 30 September 2008.

Estimating forecasts of balancing costs is not a straightforward process. Figure 1 shows that balancing costs (expressed in MCAP) have declined significantly since 2008, while Figure 2 illustrates the relativity between balancing up and balancing down over the same period.

Figure 1 Costs of balancing

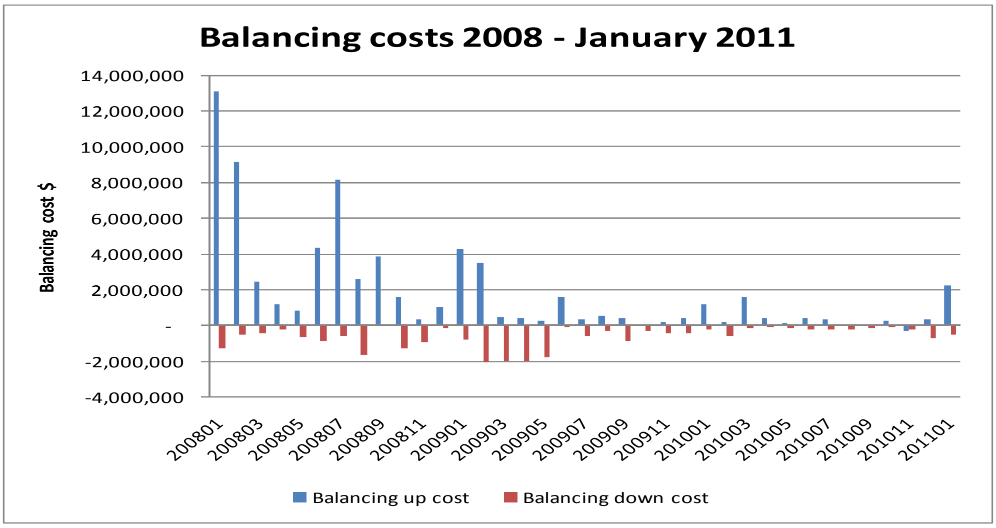
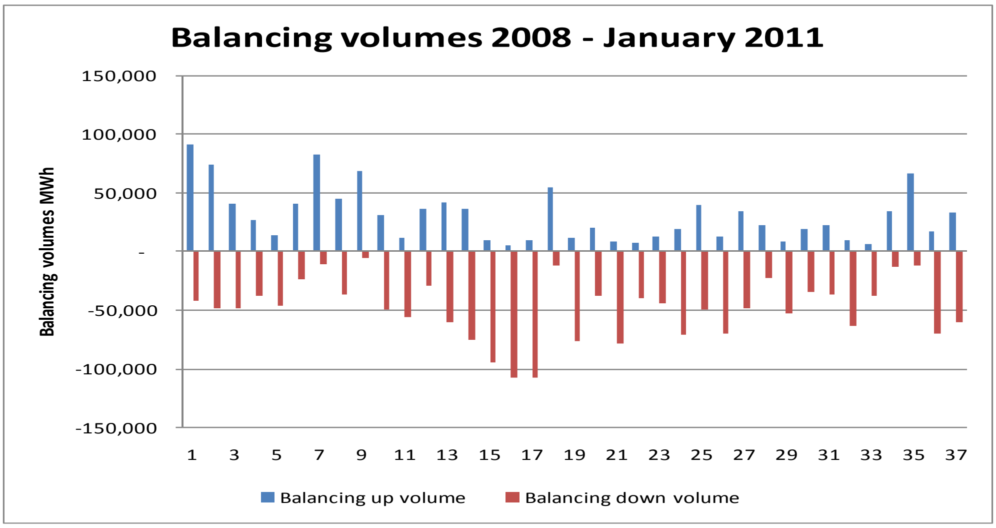


Figure 2 Balancing volumes



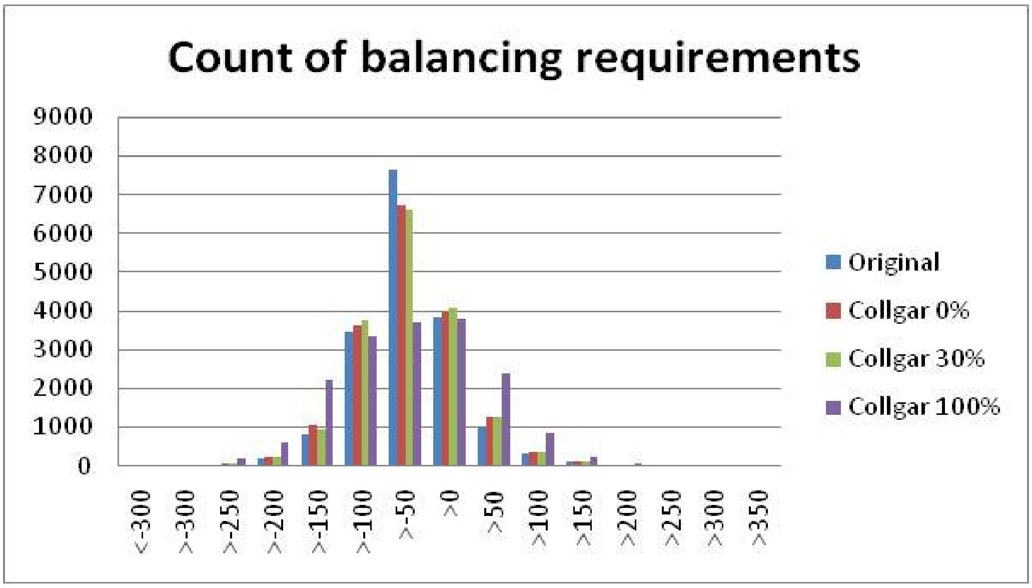
Our examination of the data shows that the distortions giving rise to balancing requirements i.e. forecasting inaccuracies, over/under submission have diminished over the past two years, which has reduced somewhat the need for balancing. At the same time there has been an increase in the "supply cushion" which explains the decreasing average STEM price.

The time frame we have looked at, since the beginning of 2008, has seen two moderately sized windfarms in operation: Emu Downs and Walkaway. However, intermittent generation has not been a major causal factor of balancing requirements. There have been trading periods where intermittent generation had a significant marginal effect, but it is not a significant contributor to overall balancing volumes.

Within our time frame there will be a number of changes to the composition of the generating fleet in the WEM and of demand as outlined in the Statement of Opportunities. These will have an effect both on the amount of balancing required and the availability of generation to assist with balancing.

We have modelled the effect of the Collgar wind farm on balancing. We have assumed that it will become fully operational in April 2012 at its stated capacity. Its operating characteristics will be similar to the existing wind farms and the capacity credits awarded to it accurately reflect its average output. The outputs of Walkaway and Emu Downs are correlated at around 40%. In this analysis we have assumed a correlation of 30% between the future Collgar farm and the existing farms. Figure 3 shows the effect of different correlations on balancing volumes. As can be expected, the higher the correlation, the more volatile the balancing requirements – as peaks and troughs in production are exacerbated.

Figure 3 Collgar correlation and balancing requirements



Our analysis has shown that even as annual consumption increases the need for balancing does not. We have not observed a strong link between increasing load and increasing balancing requirements.

The weighted average STEM price in the year 2009/10 was significantly below previous years. The weighted average price in 2009/10 was $27.88/MWh, compared to $52.09 for the three years to 30 September 2010. We believe that the price in the year 2009/10 reflects an unusually large supply cushion, a situation that it unlikely to last. For that reason we have decided to scale some of the results up to reflect the likelihood of a steeper price curve. The scaling factor we have derived is 1.0849. We apply this factor to the relevant results as a one-off effect from 2011/12.

5 Impacts of proposal

This section identifies and discusses the costs and benefits associated with the proposal, focussing on the direct and tangible impacts firstly, before commenting on impacts that are less quantifiable and not able to be captured with any precision in this study (e.g. longer-term and/or qualitative impacts).

With reference to Table 1, the cost categories are essentially the same as those in the table. On the benefits side there are essentially two categories where direct, quantifiable benefits can be obtained. The first category is so-called availability benefits, made up of the following:

- IPP STEM offers not currently dispatched.
- Changes to bidding behaviour from compressed timeframes.
- Increased availability of generation following outages.

The second category includes the costs avoided as a result of not having to curtail baseload generation.

5.1 Costs

As shown in Table 1 above, the main cost categories relate to personnel and systems changes. The costs included are those specifically attributable to the balancing proposal itself. In the case of common or shared costs, where the costs are highly aggregated, we have used a top-down allocation approach, where a percentage of the shared or common costs are attributed to the proposal. Where costs would have been incurred in the absence of the proposal (e.g. expenditure on systems upgrades that would have taken place regardless of the balancing market proposal) then these costs have been excluded.

Discussions with stakeholders were use to make appropriate judgements on the quantum of costs included in the analysis. Given the evolving nature of the proposal design, these costs are still largely indicative. For this reason, we present cost ranges, rather than point estimates.

General assumptions used to determine the costs of the proposal are as follows:[8]

- Stakeholders will undertake the necessary investment to allow participation in the balancing market regardless of their (expected) actual degree of participation (i.e. cost estimates are not adjusted to assumed participation levels).
- The prices associated with key inputs (e.g. labour and capital) reflect the scarcity of such inputs (i.e. costs assume availability of inputs).
- The price of labour remains unchanged over the study period (i.e. we have not inflated the estimated salary costs over time).
- With the exception of System Management, no explicit labour productivity adjustment has been assumed.[9]
- There is some degree of uniformity in requirements between stakeholders (i.e. cost estimates for participants can be applied to others, in a broad sense).
- A seven-year project life.
- Full implementation and set-up for all participants will be completed within two (calendar) years of approval.
- A discount rate of 8% applies.[10]

5.1.1 Total costs

Table 2 shows the total estimated costs associated with the balancing market proposal for "high" (**$30.22million**) and 'low**"** (**$19.45 million**) cost scenarios

---

[8] Additional, more specific assumptions relating to particular estimates are detailed in the subsequent sections concerning the particular cost estimates.

[9] This productivity adjustment is predicated on assumed labour-saving and/or labour-enhancing properties from automation of processes. In the case of System Management we have applied a 10% per year cost reduction factor (to the ongoing personnel required) in the low-cost scenario, a 5% per year cost reduction in the medium scenario and have left ongoing personnel costs unaffected in the high cost scenario.

[10] In deciding which discount rate to use, we searched for an "industry standard" discount rate used in terms of electricity investment in Western Australia, but were not able to determine that such a thing existed, or even if it would be useful for a project such as this as net economic benefits are not typically discounted at, for instance, estimated WACC. We are comfortable with 8% as a central figure. Sensitivity to the discount rate is explored below.

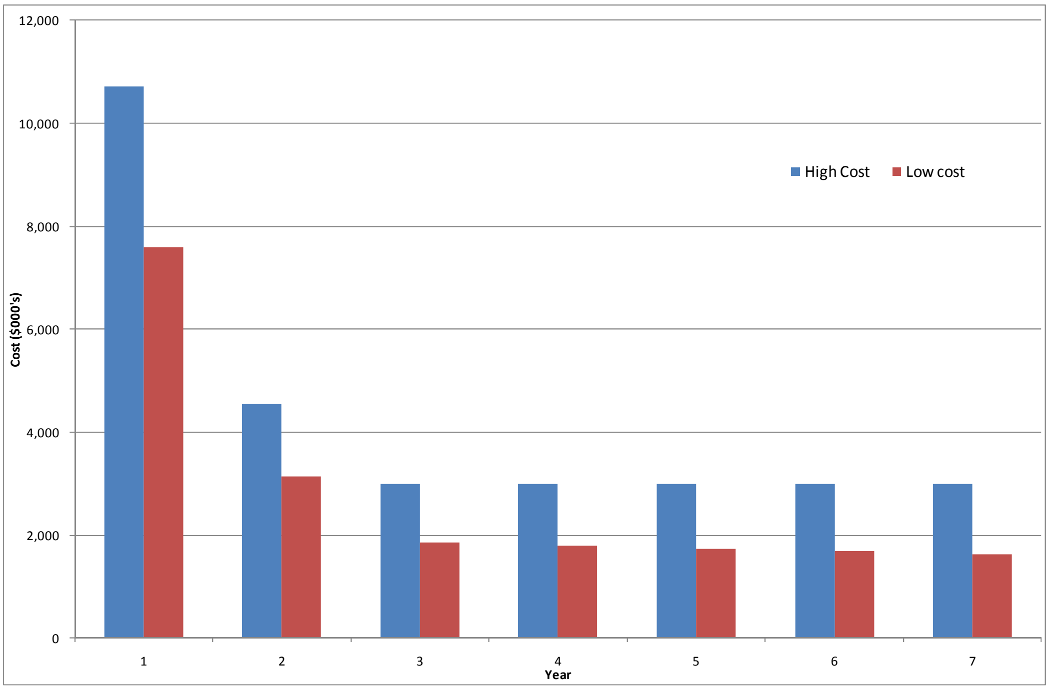
respectively. The figures indicate the relatively intensive upfront commitment associated with the proposal - see the broad cost profile in Figure 4 below. The “high cost” scenario estimate of total costs is therefore around 55% higher than the “low cost” scenario.

Set-up and implementation costs represent around 42% of total (undiscounted) costs in the “high cost” scenario and around 47% of total (undiscounted) costs in the “low cost” scenario.

Table 2 Total cost (undiscounted)

Description	Costs -$ (High)	Costs -$ (Low)
Set-up and implementation	$12.70 m (over two years)	$9.15 m (over two years)
Ongoing	$17.52 m (over five years)	$10.30 m (over five years)
TOTAL	**$30.22 m**	**$19.45 m**

Figure 4 Cost profile



The major difference between the two cost scenarios is that the “low cost” scenario assumes that costs for System Management are 50% below those associated with the "high cost" scenario.[11] In addition, costs for the remaining stakeholders are reduced (from "high cost" scenario levels) by the same proportion as indicated by IMO costs. That is, the IMO identified that their actual costs related to balancing ranged between 90% and 70% of MEP costs. The lower bound of this range is around 78% of the upper bound and thus, costs were scaled down by that percentage. For example, costs of $100 in the "high cost" scenario would be $77.78 in the "low cost" scenario. In effect, we assumed the interval identified by the IMO as appropriate for all other participants, in the absence of available evidence to the contrary.

For both scenarios we have assumed that only one third of ongoing labour costs are incurred in the first year and half in the second year. This assumption allows for the time required to set-up, test and then implement required systems changes. Thus, there is some degree of overlap in terms of the two-year and five-year separation between "one off" and ongoing costs highlighted in the table.

While not reported in detail here, we also derived a "medium" scenario. This scenario assumes the midpoint for IMO costs (80%) and a scaling factor for all other participants costs (excluding System Management) of around 89%. In relation to System Management we have assumed that costs are 25% below the "high" scenario. This scenario is used more extensively in subsequent sections.

5.1.2 Cost detail

Table 3 below presents the costs in more detail. It shows that, in relation to the "one-off" costs associated with set-up and implementation, system assets are the predominant cost category. As expected, the labour component of set-up and implementation costs is relatively minor, but total ongoing labour costs are significant (across a longer time period).[12]

Table 4 shows the high and low costs by stakeholder. The majority of costs accrue to System Management and the IMO respectively. The IPPs category includes costs identified for Verve Energy. In reality the costs incurred by IPPs (excluding Verve Energy) are relatively minor. This table again highlights the impact of cost assumptions for System Management. The low cost scenario assumes a 50%

[11] The costings we received from System Management were expressed as "orders of magnitude" with an error bound of up to 50%.

[12] The key assumptions used for labour costs are that a trader/analyst is paid a salary of $100k and a system operator/engineer is paid a salary of $95k. Factoring in overheads of 50% results in cost figures of $150k and $142.5k respectively.

reduction in costs as well as a 10% productivity payoff in terms of ongoing labour costs related to this proposal.

Table 3 Further cost details (undiscounted)

Description	High cost, $ (% of total)	Low cost, $ (% of total)
Personnel- ongoing	$17.52 m (58%)	$10.30 m (53%)
Personnel- set-up and implementation	$1.43 m (5%)	$1.14 m (6%)
Systems- assets	$7.05 m (23%)	$5.26 m (27%)
Systems- processes	$4.22 m (14%)	$2.75 m (14%)
TOTAL	**$30.22 m**	**$19.45 m**

Table 4 Stakeholder cost detail (undiscounted)

Stakeholder	High cost, $ (% of total)	Low cost, $ (% of total)
System Management	$11.30 m (37%)	$4.72 m (24%)
IMO	$7.64 m (25%)	$5.94 m (31%)
IPPs[13]	$11.28 m (38%)	$8.79 m (45%)

[13] For the purposes of this report, IPPs include Verve Energy.

5.2 Direct benefits[14]

We have drawn on the paper on Balancing Support[15] presented to the RDIWG on 23 November 2010 in this section. We assess the overall economic benefits, not the effects on individual participants. While some of the extreme events that have taken place recently (such as on 10/11 January) may have had significant effects on individual participants, if these costs are offset by equal benefits to other parties then they have no relevance to an assessment of changes to resources available to the economy and therefore cannot be included in the analysis. We have not quantified the benefits to parties of reduced volatility; however, we have addressed this point in the qualitative benefits.

We discuss in turn the following direct benefits from the new balancing market:

(i) An ability by IPPs to clear their existing unused STEM offers ;

(ii) A marginal increase in the bidding of capacity given that compressed time frames allow participants to recast their bids based on new information.

(iii) The return of capacity from outages.

(iv) Fewer curtailments of base load generation.

5.2.1 IPP offers to STEM available for balancing

The benefits estimated in this section result from improved scheduling of generation. Currently, because IPPs are excluded from balancing except for system security or to ensure dispatch in the merit order before distillates, there are occasions where inefficient costs are incurred. For instance, Verve generation is dispatched when cheaper IPP generation was available on the STEM curve. Similarly, Verve generation is curtailed when it would have been cheaper to curtail a more expensive IPP generator.

This possible benefit is contingent on the assumption that IPPs are willing to generate or be curtailed as signalled in their STEM offers.

[14] A description of the process of estimating benefits relating to all relevant categories in included as an appendix.

[15] Balancing Support, IMO paper, 23 November 2010

From our discussions with IPPs we have established that there is interest in taking part in balancing were the opportunity to become available.

The difficulty lies in assessing how much IPP generation becomes available for balancing and whether it will displace Verve generation appropriately in the merit order. With such uncertainty in mind, we have taken a conservative approach to estimating the benefits.

The Balancing Support paper captures a number of the benefits that are available. That paper looked at what current STEM offers by IPPs would have been accepted had system management been able to dispatch them. It estimated for the year 2009/10 that there were potentially $2.7m of savings to be made. We estimate that with the advent of the Collgar wind farm that the total savings/benefits are **$3.05m in 2011/12**. We believe that this is a reasonable estimate of the economic advantages related solely to IPPs that were available to the STEM and are now available for balancing.

We consider this estimate is likely to increase over the next few years given that there could be greater availability of fast start plant than during the period analysed.

We note that this benefit amounts to $174 per trading period.

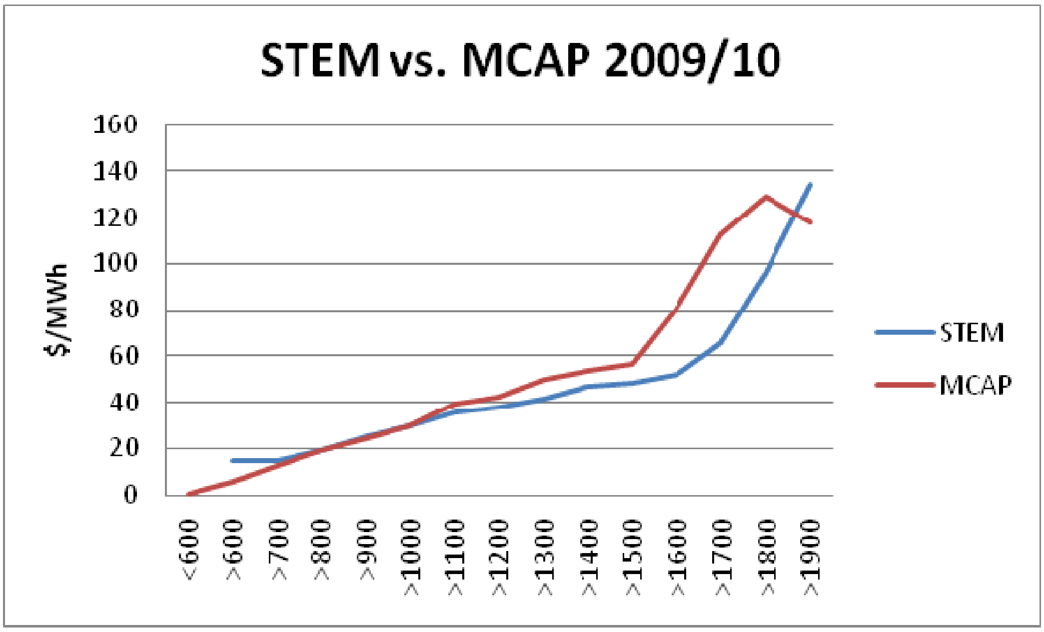
We have also performed some analysis on participation scenarios which we estimate could run between 90% and 100%. The reason we assume relatively high participation is that there is no assumption made on any change in current behaviour. The analysis that was performed captures most of the benefits from relatively small changes in load meaning that these changes in generation for IPPs are simple to effect and do not require a substantial change to fuel positions.

This benefit has been scaled up to reflect the likelihood of a steeper price curve in future years. It has also been scaled up to reflect the advent of the Collgar windfarm on results.

5.2.2 Reactions to more recent information

Most bidders, because of the type of plant they have, take into consideration inter-temporal factors when formulating bids. Baseload generation with slow start-up times will often be bid into the market at prices significantly less than SRMC to ensure that it is not curtailed during low demand periods. Likewise, there are many occasions where schedulers prefer not to have plant that is only part-dispatched and will price it high to ensure that it is not dispatched at all. The effect of this is that the STEM offer curve can only be considered an accurate signal of intentions to generate or to be curtailed at the margins of the load forecast. This can perhaps best be illustrated by comparing the MCAP and STEM curves for 2009/10 at different load intervals (see Figure 5).

Figure 5 STEM and MCAP comparison 2009/10



As the figure illustrates, even though MCAP is calculated using the same offer information as the STEM, there is a significant difference between the two price curves[16]. The reason for this is that participants form expectations as to the load forecast and bid accordingly. If load is high then more generation is made available. The reverse is also true.

Traders have to take into account minimum operating ranges for plant. Traders will know based on their observations of historic load levels and of other plant outages whether their plant is likely to be dispatched. This has an effect on how generation is bid into the market. It can have the effect of both under and over-bidding (in price terms) to ensure that the outcome that the trader wants is achieved. Once plant reaches its minimum operating range there is more of an expectation that bids will lie close to the SRMC, however, there is a certain degree of distortion once balancing exceeds relatively small bounds.

Figure 6 illustrates the nature of IPP bidding as it stands. This chart is for 2009/10 and shows how, on average, the majority of IPP generation is offered in at price

[16] Readers will note that there is an anomaly at the upper end of the load range. There are fewer observations at this load range so it is more vulnerable to distortions.

caps. If even a fraction of this generation can be made available to be cleared at dispatchable prices then the benefits are potentially significant.

Figure 6 – IPP STEM submissions 2009/10

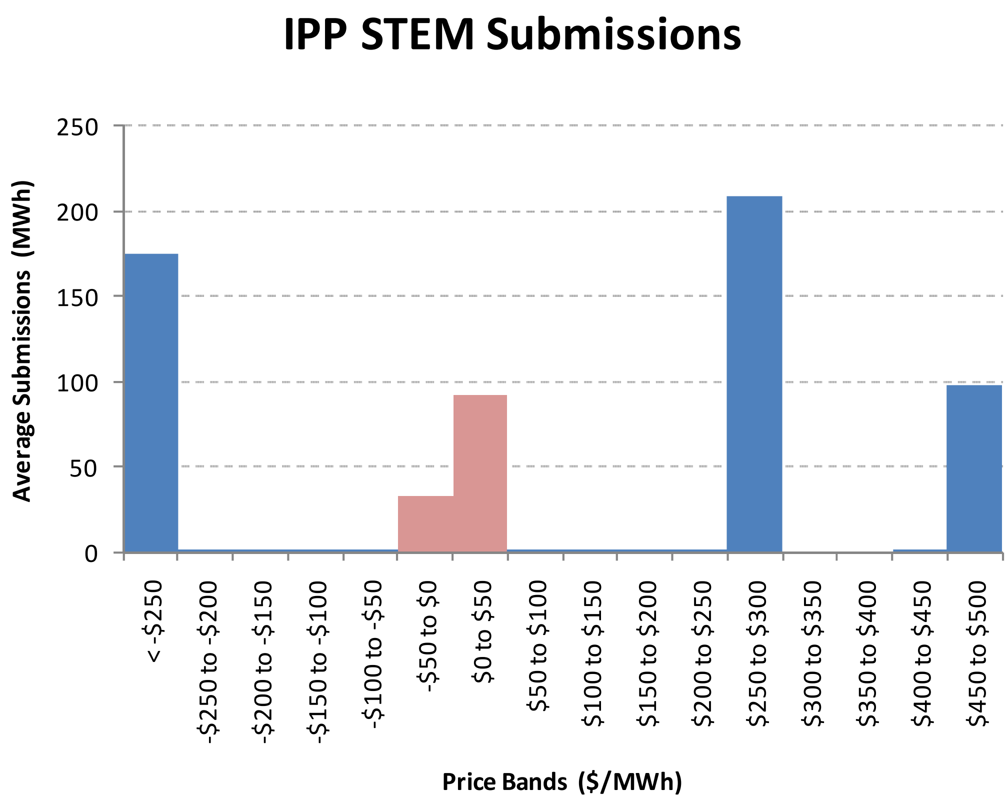
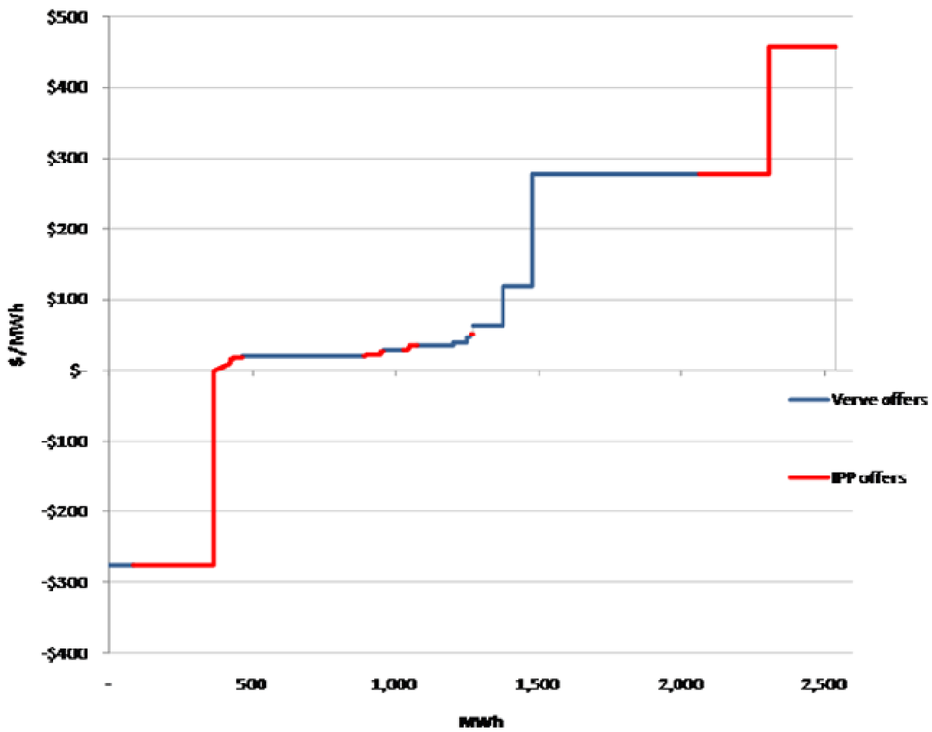


Figure 7 shows for a single trading period what the STEM price curve looks like. As can be seen there is some IPP generation that is priced closed to the clearing price ($26/MWh) but the bulk of generation has been priced at the extremes. This high/low priced generation might be rebid in a balancing market to be brought into the merit order, which could result in fewer extreme deviations.

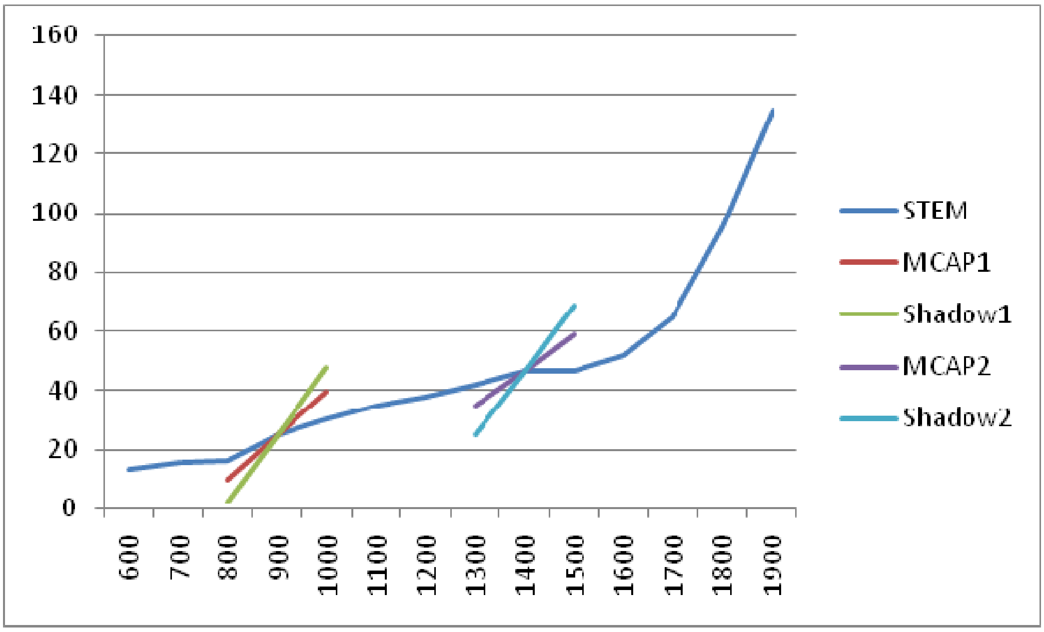
Figure 7 – Offers for 7 February 2010 at 5pm



Another factor which causes offers to chase load is that participants with a limited stock of fuel will look to maximise revenue throughout the whole day rather than treat each trading period equally. Generation that is available for one trading period might not be available for another if fuel is limited. The obvious consequence of this is that plant is bid in for the higher price periods at dispatchable prices and during lower price periods is bid in at higher cost. This factor also contributes to distortions in the balancing outcomes that are observed presently.

Conceptually, what is happening is shown in Figure 6. For each load forecast there is an MCAP deviation curve that represents the willingness of participants to move from their current levels of production based on their previous day submissions. However, there is also a shadow MCAP deviation curve that represents the reality that only Verve resources are used for balancing, leaving out other, possibly in-merit, production. The Balancing Support paper itemises the advantages that accrue when moving from the shadow deviation curve to the MCAP curve. We have captured the benefits that are potentially available when the MCAP curve approaches the STEM curve.

Figure 6 Conceptualisation of MCAP-STEM divergence



It is important not to overstate these benefits as there will always be a degree of uncertainty even with a two-hour window before dispatch. Furthermore, in cases where balancing is driven by a plant outage then it is possible to overstate the benefits considerably if we assume that plant is still available for balancing.

The method we have used involves estimating the surplus that is available if the MCAP curve graphed above were to tend towards the STEM price curve. Such an approach yields between **$2.17m** and **$3.62m** of benefits. Because of the distortions involved in the current calculation of MCAP and because the STEM is formed on uncertain information it is important to show care in calculating the possible benefits.[17] We have assumed that participation could vary between 60% (low case) and 100% (high case) when calculating this benefit. Note that even if a single IPP were to participate in balancing the participation might exceed 50% given the balancing volumes.

[17] These distortions were detailed in the paper on Balancing price formation (IMO paper, 2 November 2010) which showed the impact on MCAP of relevant quantity inconsistencies. We have attempted to remove some of the relevant quantity inconsistencies to ensure that the starting point for balancing is correct. Currently, for small volumes of balancing down (less than 2MW, MCAP actually exceeds STEM on average).

We have also been able to test these numbers against some information provided to us by market participants and are satisfied that the participation assumptions and the magnitude of the benefit are correct.

This benefit has been scaled up to reflect a steeper price curve in future years but no adjustment has been made to balancing volumes when estimating the value of the benefit.

5.2.3 Early plant return following forced outages

Another quantifiable benefit of availability is from early return to production following forced outages. At present because of the early gate closure for trading, there is less generation made available for dispatch than there might otherwise be. There are two reasons for this. One is that a cautious participant may not want to schedule plant that is due to come back to service but with some uncertainty. This is because that participant can incur DDAP penalties if that plant is not ready to generate. The second concerns situations where plant does become available earlier than expected for dispatch. This generation would be available for balancing, even if not available for dispatch. We estimate that around 72GWh of cheaper generation might be dispatched, which would displace more expensive generation. We estimate that the saving would amount to $13.33/MWh (at 2009/10 prices) and that the total savings for 2011/12 would be around **$0.96m**.

This estimate is based on 1000MW of IPP generation available for three extra days in the year. The $13.33/MWh is an estimate of the displacement of more expensive generation.[18] It is accepted that these numbers are averaged at quite a high level; however discussions with participants regarding some specific events give us comfort as to the magnitudes.

No scaling has been performed on these results.

5.2.4 Reduction in cycling costs

The final quantifiable benefit is that it is less likely that baseload generation will have to be curtailed. We understand that the costs of having to cycle a thermal generator are around $40k per event.[19] We have estimated that, based on recent practice, with

[18] This number has been calculated by removing 200MW from the offers stack at various load levels and noting the effect. The results are weighted across all load scenarios so as not to be distorted by a few high prices.

[19] See The Cost of Cycling Coal Fired Power Plants, Steven A. Lefton, Power Plant O&M and Asset Optimisation, 2006.

a more efficient balancing system there may be 30 fewer curtailment events compared with the alternative, or a saving of **$1.2m** per annum.

Further information on the effect of the Collgar wind farm suggests that the amount of cycling could increase around five-fold. If the balancing market were able to prevent that cycling from happening then that suggests that a saving of $6m would be possible. There are two reasons why this assertion could be problematic.

First, if that level of cycling were to emerge then it could cause irreparable damage to plant, which would force investment into new plant that would cope better with cycling.

Second, under the status quo arrangements it is possible for balancing support contracts to be entered into. These contracts, while still not nearly as efficient as a transparent balancing regime, would still result in some advantages over current practice if they were to result in a reduction of cycling events.

Given that balancing support contracts have not emerged with the current level of cycling it might be safe to assume that there is still some increased level of cycling that would be acceptable, even if a five-fold increase would be clearly unacceptable. We have assumed, therefore, that a balancing market would result in 45 fewer cycling events over the status quo, or a saving of **$1.8m**, from the introduction of Collgar.

No scaling has been performed on these results.

5.2.5 Summary of direct benefits

Table 5 contains benefits estimates across categories and years. These benefits range from **$46.30 million** in the low scenario to **$56.89 million** in the high scenario. It is important to note that, in order to account for set-up and implementation requirements this stream of benefits is for the years 2011/12- 2016/17 only.

Case study one – an outage

Note that the numbers used in this example regarding offers are illustrative only and are not intended to reflect the position of any participant.

On 10 January 2011 an unplanned outage at one of Griffin's Bluewater units caused some extreme pricing of MCAP. For 17 trading periods on 10 January, MCAP was at its cap of $336/MWh. The STEM price did not exceed $65/MWh on 10/11 January.*Part one: IPP changes offer*

Let us suppose that there was an IPP that was willing to generate 200MW at $100/MWh for both days. Let us suppose also that the true cost of the highest price cleared Verve offer was 85% of the stated MCAP price (which also allows for the possibility of the highest priced offer being only partially cleared). There were 33 trading periods where there was 200MW of balancing required where MCAP was greater than $100/MWh. Calculating this benefit (e.g. for 12:00-12:30 on 10 January when MCAP was $336/MWh) gives the following: [$336*.85 - $100] * 200/2 = $18,560.

The assumption being made is that the IPP is displacing 200MW of generation which had a SRMC of $285.60 (336*.85).

Adding up the results for all the trading periods where the above criteria were met on 10/11 January would result in an economic saving of $470,000.

Part 2 – early return to service

Let us suppose now that because the cause of the forced outage was unknown, the IPP was unsure of when it was safe to recommence bidding into the STEM. Suppose that its own SRMC is $25/MWh and that because of the early gate closure it lost out on 20 trading periods when the highest price cleared offer was $70/MWh, which represented a participant with 200MW of energy which was fully cleared. Under a balancing regime, this IPP could return to service for those 20 trading periods and displace the highest price cleared offers up to its capacity. The benefit can be represented as follows: [70-25] * 200/2 * 20 = $90,000

Case study two – curtailment of base load plant

In this scenario, higher than forecast wind in the early morning trading periods has forced the shutdown of a Verve coal unit which had been running at 150MW. At the time of the shutdown there was IPP generation at more modern baseload facilities that could have been curtailed of 150MW. The STEM price was $50/MWh. Verve had signalled a decommitment price of -$10/MWh at one of its coal units. The IPP was willing to curtail its baseload at $10/MWh, but had offered the generation into the market at -$200/MWh to ensure dispatch. The curtailment lasted 10 trading periods.

Advantage two – IPP rebidding

In this case the IPP decides to rebid its generation at $10/MWh. The advantage is the difference between the IPP SRMC and Verve's SRMC for 150MW over 10 trading periods or: 150/2 * ($10 – (-$10)) * 10 = $15,000

Advantage four – no curtailment of unsuitable plant

Because Verve did not signal the capital cost of the curtailment in its bid we assume that another $40,000 of costs are avoided by having a modern IPP baseload facility curtail its plant, which would not incur the same wear and tear on its machinery.

Table 5 Benefit summary (undiscounted)

	2010/11[20]	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Availability benefits ($m)								
Use of current IPP offers in STEM	2.57	2.90	3.01	3.01	3.01	3.01	3.01	3.01
Further IPP generation available from more timely information	2.51	2.72	2.72	2.72	2.72	2.72	2.72	2.72
Further IPP generation available from early outage return	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Sub-total availability benefits	**5.76**	**6.57**	**6.69**	**6.69**	**6.69**	**6.69**	**6.69**	**6.69**
Cost saving from avoiding cycling plant	1.2	1.5	1.8	1.8	1.8	1.8	1.8	1.8
Total quantifiable benefits- medium scenario	**7.23**	**8.07**	**8.49**	**8.49**	**8.49**	**8.49**	**8.49**	**8.49**
Total quantifiable benefits- low scenario	**6.59**	**7.38**	**7.79**	**7.79**	**7.79**	**7.79**	**7.79**	**7.79**

[20] For illustration only

Total quantifiable benefits- high scenario	**8.20**	**9.13**	**9.55**	**9.55**	**9.55**	**9.55**	**9.55**	

6 Net effects

Having separately considered the costs and benefits in the section above, we now turn to the integration of such impacts. Reiterating, the period for the analysis is seven years. However, to allow for the set-up, implementation and testing requirements discussed previously, the comparison is essentially between seven years of cost and six years of benefit; i.e. we have assumed no benefits accrue at all in the first year while set up is taking place.

6.1 Summary results

Table 6 presents summary results comparing the discounted costs and benefits for those categories of benefit where quantification is possible. The scenarios presented are as follows:

- *High*: low cost and high benefit
- *Medium*: medium cost and medium benefit
- *Low*: high cost and low benefit

All of the scenarios result in a positive benefit-cost ratio (BCR). That is, there is a net benefit to society from the proposal. Even the most pessimistic scenario results in benefits that outweigh costs. Conversely the most optimistic scenario results in benefits that are around twice the costs of the proposal. While there is some risk comparing proposals in terms of subject matter, the calculation of (monetised) benefit-cost ratios does allow these estimates to be compared with alternative investments including "doing nothing".

It is important to keep in mind that these results do not include indirect or qualitative benefits.

Table 6 Summary results for quantifiable categories

	High	Medium	Low
Total benefits	$40.52 m	$35.98 m	$32.97 m
Total costs	$15.72 m	$19.71 m	$24.06 m
Net benefits	$24.81 m	$16.27 m	$8.91 m
Benefit-cost ratio	**2.58**	**1.83**	**1.37**

6.2 Sensitivity analysis

In addition to the summary results shown above, this section considers the impacts of adjusting key assumptions and testing alternative scenarios. While there are myriad factors that can potentially be altered, we focus our attention on the following:

- Combinations of (already modelled) cost and benefit scenarios
- Alternative parameters (e.g. study period, discount rate)
- Alternative cost and benefit intervals

6.2.1 Different scenarios

In addition to the three scenarios presented in Table 6, there are six further permutations (using the existing modelled parameters):

1. High cost, high benefit
2. High cost, medium benefit
3. Medium cost, low benefit
4. Medium cost, high benefit
5. Low cost, low benefit
6. Low cost, medium benefit

As might be expected, altering the relative scenarios does not materially affect the BCR (i.e. by definition, they are bounded by 2.58 and 1.37), but does give a clearer sense for possible values for both costs and benefits.

Table 7 Alternative cost and benefit scenarios

	1	2	3	4	5	6
Total benefits	$40.52 m	$35.98 m	$32.97 m	$40.52 m	$32.97 m	$35.97 m
Total costs	$24.06 m	$24.06 m	$19.71 m	$19.71 m	$15.72 m	$15.72 m
Net benefits	$16.46 m	$11.92 m	$13.26 m	$20.81 m	$17.25 m	$20.26 m
Benefit-cost ratio	**1.68**	**1.50**	**1.67**	**2.06**	**2.10**	**2.29**

6.2.2 Alternative parameter values

We now consider the effect of alterations to the time period under study, the discount rate applied and cost/availability of employed labour.[21] We examine the effects of such changes with reference to the "medium" scenario above.

Table 8 shows the effect on net benefits and the BCR from different discount rates, relative to the "medium" scenario. A higher discount rate means we place less value on benefits (and costs) incurred in the future than we do at present, while the opposite is also true. As mentioned in the assumptions above, we were unable to find an appropriate "industry standard" discount rate to use.

Given the benefits increase over time while the costs decrease, we would expect some asymmetry in the BCR as the discount rate gets higher. While this is true, the figures show that, in general the BCR is relatively insensitive to changes in the discount rate. Only at a discount rate greater than around 55% would the BCR reduce to below "break even" (i.e. costs exceed benefits).[22]

Table 8 Alternative discount rates

	Original scenario	Very low disc. rate	Moderately low disc.rate	Moderately high disc. rate	Very high disc. rate
Discount rate	8%	2%	5%	11%	20%
Net benefits	$16.27 m	$23.07 m	$19.36 m	$13.68 m	$8.10m
Benefit-cost ratio	**1.83**	**2.00**	**1.91**	**1.75**	**1.54**

Table 9 shows the effect of altering the time period for the analysis (again relative to the original "medium" scenario). With a severely truncated study period of three

[21] By employed labour we refer to employees and salary rates as opposed to contracted labour. While the scenario analysis implicitly includes changes to labour cost, it does so in a general sense (i.e. all other input costs changes as well). Here we are focussing specifically on labour cost changes, holding all other costs constant. By changing cost, we are indirectly accounting for scarcity.

[22] A discount rate of 55% would indicate that the value of a dollar in one year is less than half the value of receiving that dollar today. Such a discount rate is outside reasonable bounds for this type of analysis.

years the costs are roughly equal to the benefits of the proposal (this is effectively the payback period in present value terms). A moderately truncated study period of five years substantially reduces the net benefit from around $16m to almost $9m, but still has a strongly positive BCR of 1.51.

Table 9 Alternative study periods

	Original scenario	Heavily truncated time period	Moderately truncated time period
Study period	7 years	3 years	5 years
Total benefits	$35.98 m	$13.66 m	$25.67 m
Total costs	$19.71 m	$13.69 m	$16.99 m
Net benefits	$16.27 m	-$0.03 m	$8.68 m
Benefit-cost ratio	**1.83**	**1.00**	**1.51**

Table 10 indicates that if ongoing employed labour costs were to increase by a quarter (and all other costs were to remain the same) then the net benefit of the proposal reduces from $16.27m to $14.92m and the BCR from 1.83 to 1.71. Combining the effect of a shorter time period of five years, and an increase in ongoing employed labour costs of 25%, results in the net benefit dropping to $7.75m and the BCR to 1.43. With a truncated study period of five years, a labour cost premium of 25% (to reflect scarcity) and a discount rate of 41.5%, the proposal “breaks even” with a BCR of around 1 and net benefits of $31,000.

Table 10 Increased labour costs and a truncated study period

	Original scenario	Labour costs increase by 25%	Moderately truncated time period
Study period	7 years	7 years	5 years
Total benefits	$35.98 m	$35.98 m	$25.67 m
Total costs	$19.71 m	$21.06 m	$17.92 m
Net benefits	$16.27 m	$14.92 m	$7.75 m

Benefit-cost ratio	**1.83**	**1.71**	**1.43**

6.2.3 Summary

Overall, the results are robust to changes in key assumptions and parameters, both individually and in combinations. The vast majority of changes still result in net benefit to society. Time period is the factor where there is most sensitivity.

6.3 Other effects

As mentioned in section 3 above, the impacts of the balancing proposal are not restricted solely to the quantifiable impacts we have summarised. There are additional benefits that are either not amenable to quantification (e.g. effects on confidence) or that occur outside the relevant study period (e.g. longer-term effects on investment incentives). In addition, there are other effects that have been raised by participants- the most obvious being so-called "clean price" impacts.

We have not modelled the potential benefits in terms of investment incentives, confidence and "clean price" impacts, but discuss each of these possible effects below. While our discussion considers the effects individually, we wish to note that there are likely to be strong interactive effects. That is, the effects mentioned are best thought of as complements rather than substitutes.

Overall, our assessment is that these other effects are likely to be positive for the basic results derived above. While there may be some unquantifiable costs associated with transitioning to the new balancing market, we assess these to be relatively minor, and outweighed by the potential addition to the benefits associated with the proposal, even if these cannot be enumerated with any precision in this study.

6.3.1 Investment incentives

Creating appropriate investment incentives for new generating capacity has been a key motivating factor in electricity market liberalisation initiatives the world over. Experience with reforms in the 1990's suggested that competitive wholesale markets could and would mobilise adequate (or more than adequate) investment in new generating capacity.[23] On its own, a proposal to introduce competition to

[23] Joskow P (2008) "Lessons Learned from Electricity Market Liberalization." The Energy Journal, v29, special issue #2, pp.9-42.

balancing would not be likely to significantly influence investment decisions. Stakeholder discussions confirmed this view, with other factors such as reserve capacity mechanisms having greater influence.

Nevertheless, the proposal is unlikely to have no effect at all on investment incentives. As part of a wider package involving privatisation of state-owned enterprises, vertical and horizontal restructuring to facilitate competition and mitigate self-dealing and cross-subsidisation problems, good wholesale market designs that facilitate efficient competition among existing generators, competitive entry of new generators, and retail competition (at least for industrial customers), the balancing proposal is likely to support the investment incentives that accompany successful reform programmes (Joskow, 2008).

Using values for the capital cost from a recent AEMO report, multiplied by the installed capacity in the SWIS, we derive a crude estimate of the replacement value of current installed capacity of around $13.5 billion.[24] For illustrative purposes only, a small change in this large number would result in estimated effects that are considerably greater than the quantified effects summarised above. A 0.5% increase in the overall value of investment totals some $67.5m. We cannot claim these as benefits attributable directly to the balancing proposal, but do make the point that potential (positive) impacts on investment incentives do have the potential to add significantly to the net benefit estimates we have derived.

The scale of investment is not the only relevant dimension in this discussion. The composition of investment is likely to matter as well. All else equal, a balancing market is likely to influence the type of plant that generators will look to invest in, going forward. We would expect that generators would face stronger incentives to invest in "balancing-capable" plant than if there was no opportunity to participate in balancing provision. To the extent that such plant is more suitable to overall market operation (e.g. flexibility, better ramp rates and minimum loads), there are likely to be efficiency impacts.[25] We are not able to capture these to any extent in this analysis, but again it is important to observe the possibility of their existence.

[24] ACIL Tasman Pty Ltd (2010) "Preparation of Energy Market Modelling Data for the Energy White Paper- Supply Assumptions Report."Report for AEMO/DRET. Available at: www.aemo.com.au/planning/0400-0019.pdf

[25] Joskow (2008) refers to the application of high-powered incentives created by competitive wholesale electricity networks leading to lower generator operating costs and improved availability. We have captured only the latter in our quantified benefit estimates.

6.3.2 "Clean price" impacts and confidence

RDIWG participants have previously considered work examining the inherent distortions to the price relating to balancing. That work estimated that the "cost" of such distortions amounted to approximately $8m per annum.[26] These price effects characterise wealth transfers (as opposed to changes in real resources available to the economy) and their removal cannot be counted as economic benefits as such, they may have important behavioural impacts that are relevant.

In the case of "extreme" events such as plant tripping, the presence of the distortions exacerbates the resulting balancing impacts. In effect, the MCAP adjustment is artificially more significant than might otherwise be the case. Again, these effects are essentially transfers between parties with a net economic effect of zero, but the party on the "wrong" side of the transfer may be left questioning the stability of the operation of balancing. This uncertainty may apply more generally to participation in the WEM and ultimately have economic impacts in the form of reduced confidence and concomitantly lower levels of commitment to investment as a result.

We stress that no allowance has been made in our benefit estimates for such an occurrence being avoided as a result of the balancing proposal. The possible impacts on confidence, which were referred to indirectly by some market participants, of the balancing proposal might also increase the quantified benefits over time. We caution that the impacts are likely to manifest in the form of increased investment so should not be counted twice.

Finally, we wish to mention the role that consistency with the WEM objectives might play. As mentioned previously, the success of reform processes relies on a package of (interdependent) measures, rather than a single initiative. The WEM objectives provide a quasi measure of success in that they set out what is looking to be achieved. The balancing proposal supports the competition-driven aspects of the WEM objectives, as well as the efficiency aspects of the objectives. Joskow (2008) considers that voluntary transparent organised spot markets for energy and ancillary services (day-ahead and real-time balancing) that accommodate bilateral contracts and self-scheduling of generation if suppliers choose are basic design features that contribute (along with allocation of scarce transmission capacity) to success. This is consistent with the high-level market objectives and thus should be mutually reinforcing in terms of confidence levels.

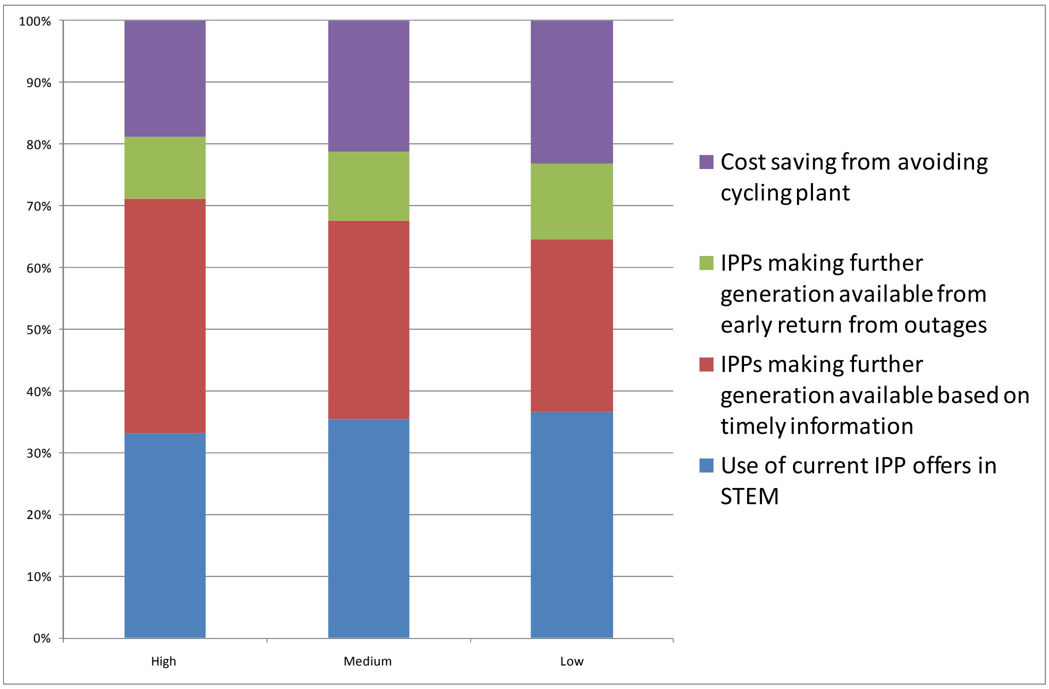
[26] See "Balancing price Formation" paper at http://www.imowa.com.au/f139,963182/Combined_RDIWG_Mtg_5_Papers.pdf

There are likely to be transitional benefits from the balancing proposal (e.g. by adapting systems, processes and people now, it becomes easier and less costly to do so in future) but there may also be transitional costs (e.g. getting "up to speed" may take longer than anticipated). Neither of these effects can be enumerated with any degree of precision.

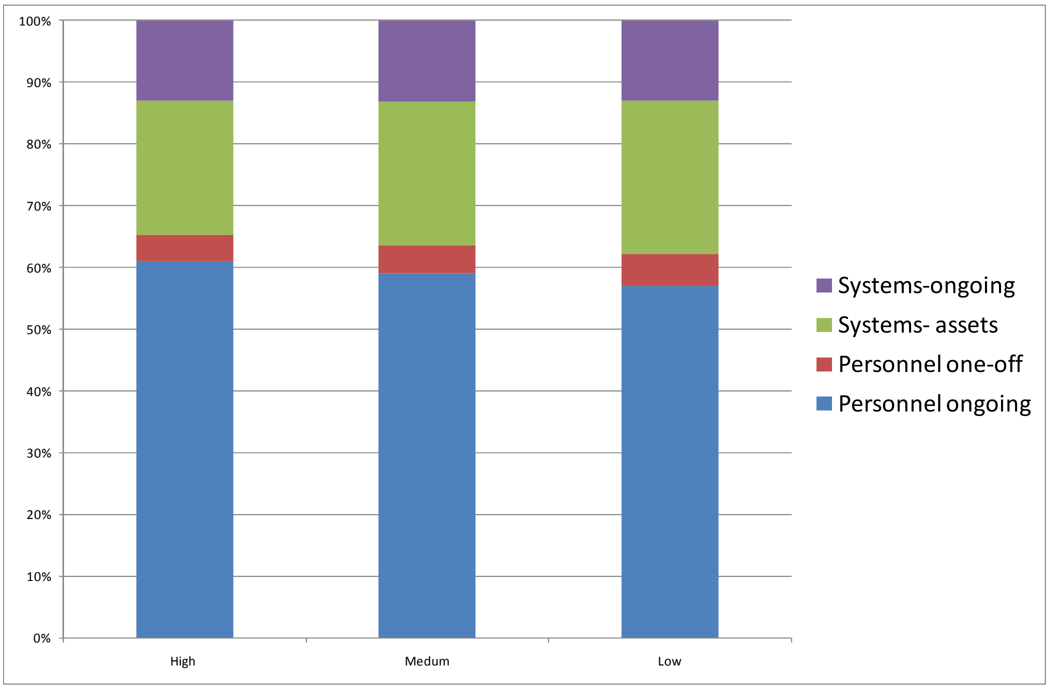
7 Conclusions

We draw the following conclusions from this work:

- Conducting a CBA specifically for competition in balancing is not a straightforward or trivial exercise, but important guidelines do exist in respect of competitive impacts in electricity markets more generally.
- CBA is the "right" method of assessment given the well-established principles and techniques embodied in the economic cost-benefit approach. That is, considering impacts economic welfare overall provides more useful information than individual party impacts, which may involve wealth transfers (as opposed changes to real resources available in the economy).
- Under reasonable assumptions, the introduction of competition/creating a balancing market will result in net benefits to society, i.e. an increase in economic welfare.
- The net benefits are estimated to range from $24.81m (at the upper end) to $8.91 (at the lower end). These figures translate into benefit-cost ratios of 2.58 (the benefits are around 158% greater than the costs) and 1.37 (the benefits are around 37% greater than the costs) respectively.
- The positive benefit-cost result is robust to alternative scenarios and a wide variety of changes to key parameters. Only more "extreme" changes such as reducing the study timeframe to below three years, or increasing the discount rate to above 55% would result in a benefit-cost ratio below the break even value of one.
- Far and away the biggest contributors to benefits are explained by IPP offers in STEM that are currently not able to be routinely dispatched (but would be able to be under the proposal) and the behavioural response from IPPs as a result of more timely information:



- The majority of costs, across the study timeframe of seven years, is explained by ongoing personnel across all scenarios, with asset-related systems changes the second biggest contributor to costs:

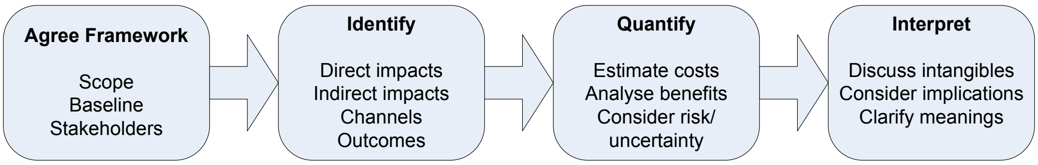


- This assessment is not just about the quantifiable impacts. Other non-quantifiable effects accrue to the proposal:
    - increased levels of confidence in the wider market (through reductions in distortions as well as proposals that are consistent with the WEM objectives);
    - improved incentives to invest (altering the level and type of investment undertaken); and
    - benefits in the form of lowered (or avoided) costs through easing the wider transitional burden towards a well-functioning market.
- These other effects cannot be included in the quantified analysis, but we assess their impact as being supportive of the positive overall contribution of the proposal.
- In sum, we estimate that there are clear efficiency-enhancing effects associated with the proposal in terms of:
    - productive efficiency- least-cost production of electricity;
    - allocative efficiency- resources devoted to generation most suitable for balancing; and
    - dynamic efficiency-producing appropriate signals around investment and encouraging innovation.

Appendix A- CBA methodology

Anatomy of a CBA

The basic analytical framework for a CBA is shown below. The aim should be to work systematically through the various steps sequentially to better highlight the basis, linkages and scale of impacts being measured. Often CBAs conflate steps two and three. We recommend these steps be separated to aid understanding, remove ambiguity and highlight the thinking that underpins the various analytical steps. In other words, we see merit in avoiding "black-box" types of analysis where the derivation of the estimated effects is difficult to understand and subsequently reproduce, replicate elsewhere, question or modify.



The framework is amenable (but not limited) to a quantitative analysis, that allows for alternative options to be compared in a consistent way. It consists of the following:

- A baseline scenario — the baseline case would represent a scenario in which no intervention would be pursued.
- Problem definition — what is the nature of the problem (including consideration of where and upon whom the effects of the problem fall)? This involves clear identification of linkages, channels through which impacts are felt, and the specific outcomes being sought.
- Option identification — a set of alternative options should be considered and developed alongside a well articulated rationale for intervention.
- Impact assessment — the benefits and costs of each option should be assessed relative to the baseline scenario (that is, it should show the net change of the option), including distributional and equity considerations.
- Interpretation — explanations of what the numbers , concepts and estimation procedures mean are crucial in terms of understanding what conclusions can (and importantly cannot) be drawn from the analysis.

Each of these points is considered in greater detail below.

Baseline scenario

The baseline, or 'business-as-usual' (BAU), case establishes the scenario in which no intervention is pursued. It provides the benchmark to assess the efficiency and effectiveness of different options.

Notably, the BAU should not depict a stagnant market. Rather, the BAU should reflect the dynamics of the WEM generally, as well as the impacts of major initiatives around the volume and composition of known investments.

Ideally, the baseline would reflect on the variables listed in the table below. However in the interests of tractability, a much smaller list of variables will be utilised.

Table 2.1: Variables considered in the BAU

Category	Variable
Economic	Household construction
	Age of household stock
Demographic	Population
	Number (and composition) of households
Energy	Energy consumption
	Electricity prices
	Investment in generation (and transmission)
Other	Weather patterns

Appropriate lifespan

'Time' is likely to be a key factor in determining the success of any change proposal. Furthermore, it is the nature of many investments that:

- most costs are borne up front; and
- benefits are accrued for a (potentially significant) period of time thereafter.

(Additionally, some maintenance and operating costs may be incurred over the life of the investment, however these are likely to be minor.)

Consequently, it is important that the analysis defines both how long a policy will induce new investment, and for how long those benefits will accrue.

In making this determination, the assessment should be realistic about the lifetime of the policy. For instance — when is it likely that a policy would be replaced? Is there a natural limit on the policy life? It is not unreasonable to limit the life of a policy of this nature to a period of 5-10 years.

Noticeably, benefits are likely to continue for a period that extends substantially beyond this. It would be appropriate to assume a benefits stream that lasts as long as any asset. This could be as long as 25 years.

Once the asset has expired, no further benefits or costs will be accrued. Although it is likely to be replaced by a like asset, the decision to reinvest is outside that of the policy.

Discount rate

Related to the above discussion is the choice of a relevant discount factor.

A discount factor allows for the comparison between streams of costs and benefits that occur at different points in time. The choice of the discount factor is especially important for the issues at hand here, because of the disjointed nature of costs and benefits. A discount factor too low is likely to over state the benefits of the proposal, while a discount factor too high, will do the reverse.

Standard public policy analysis suggests a discount rate of 10 per cent for investments of this nature. This is a default rate, meaning that alternative rates might be used if arguments can be mounted to that effect. Because of the sensitivity of the results to this factor however, it may be informative to present a range of results using a different rates (such as 5, 7 and 12 per cent).

Problem definition

Before any options (or action) are considered, it is important to crystallise precisely the problem at hand. The rationale for intervention should be grounded in overcoming a market failure, and this rationale should be clearly articulated. Moreover, appropriately identifying and defining the problem will help to guard against proposals that only act to treat symptoms, and should minimise any unintentional outcomes.

Option identification

In light of the problem definition above, the next step of the analysis is to define a set of options that may address the defined problem. It is often useful to identify a range of potential solutions. Given the work done previously by the RDIWG to determine the most viable alternative approach, we have restricted our focus to a single option.

Impact assessment

At the heart of the analysis is the impact assessment. The impact assessment considers all of the benefits and costs that are incurred as a result of the proposal/s being pursued. Note that the exercise being conducted here is different to making a business case, which considers the investment proposition from a financial (accounting) perspective. What is required is an economic perspective — it is important that the assessment be holistic in its approach and assesses the impact economy-wide. That is, an economic lens requires the CBA to be resource-based (focus on the effects (costs and benefits) on resources available to society) rather than merely financially-based.

The 'impact' should be assessed relative to the baseline scenario — that is, it should show the **net** change of the option.

Identification of costs and benefits

The analysis should attempt to identify costs and benefits incurred to the fullest extent possible. Where practical, benefits and costs should be quantified to allow for a more malleable comparison.

Non-quantifiable impacts

It will not be possible to quantify all benefits and costs. This may, for example, be due to data limitations.

Non-quantifiable impacts are still important, and are noted in the analysis along with an indication of the magnitude of those impacts and how they might impact on the assessment.

Avoid double counting

The analysis should be cautious of, and avoid, double counting of benefits and costs.

Unintended consequences

While the analysis may attempt to be holistic and identify all costs and benefits, there may be some unintended consequences that arise from the proposal.

Some unintended consequences may be identifiable as risks. There may be, for instance, uncertainty about the behaviour of market participants (i.e. will they participate fully and is the way they participate likely to be subject to strategic/gaming behaviour?). To a degree, these risks can be accounted for through a sensitivity analysis and highlighted as key assumptions to the assessment. However, others may simply not be included in the analysis.

Describe option features

Finally, having identified the net impact of the proposed option, the options need to be compared in a useful and meaningful way. This comparison can be conducted with the use of two key metrics:

- Benefit-cost ratio (BCR) — the BCR reports the ratio of benefits to costs. A BCR greater than unity implies that benefits exceed costs; and a BCR less than unity implies the reverse. Benefits and costs used to calculate the BCR are presented as the discounted sum.
- Net Present Value (NPV) — the NPV reports the net impact of the option on the economy (compared to the do-nothing BAU scenario). The streams of benefits and costs are discounted and reported in present value terms, and the NPV is calculated by subtracting the present value of costs from the present value of benefits.

Note that the BCR can be a very useful tool, especially when the benefits (or costs) of each option are the same — and only costs (or benefits) differ. For example, if different balancing options produced the same level of benefits, and what varied between each option were the costs, then the option with the greatest BCR (i.e. lower costs) would present the more obvious case to be pursued.

These two metrics will provide some assistance in making a recommendation. Excluding non-quantifiable impacts, only those options with a BCR greater than 1 (that is, an NPV greater than zero) should be considered as desirable solutions.

Sensitivity analysis

A sensitivity analysis should support the assessment — especially where the degree of uncertainty is high.

A useful tool for testing the sensitivity of the BCR and NPV to the various assumptions made is a 'breakeven analysis.' Under the breakeven analysis, key variables are individually increased (for costs) or decreased (for benefits) until the BCR is reduced to unity. (This is the same as having an NPV of zero.). The analysis shows the degree to which it is necessary for costs to rise, or benefits to fall, before the option breaks even.

Appendix B- Forecast and benefits estimation methodology

Balancing forecasts with addition of Collgar

A. *for 0% correlation*

1. Work out variations from average production in MWh for existing wind farms
2. Assume that same distribution exists for Collgar
3. Scale the variations up to Collgar's average production
4. Enumerate the number of times that Collgar causes balancing to go vary in bands of 50MW
5. Apply variations to balancing distribution

B. *for 100% correlation*

1. Multiply existing variations of wind from average by scaling factor to get Collgar production

C. *for 30% correlation*

1. Scale intermittent generation to Collgar average (i.e. capacity credit number) and reduce to 30%. Distribute the remaining 70% randomly across trading periods.

Calculating benefits from displacement of generation

A. *Estimate advantage from MCAP approaching STEM*

1. Develop a grid for load (100MWh bands) and balancing (50MWh bands) pairs
2. For each pair calculate the expected STEM price on forecast load, the expected STEM price on revised load, and the expected MCAP on revised load
3. Count the number of occurrences of each pair
4. Calculate the surplus by estimating the area below each change in circumstances; then calculate the difference.

Issues: how much of the curve to assume; how steep to make benefits.

Calculating availability following outage benefits

1. Calculate a reasonable number of trading periods of additional availability
2. Calculate a reasonable estimate of displacement cost advantage by estimating the effect of 200MW of lost generation at different load intervals (result $13.33/MWh)

Scaling the benefits

1. Use change in slope of STEM price curve to scale advantages

Calculating cycling plant costs (avoided)

1. Estimate the number of times plant has to be cycled
2. Use international standard to estimate cost per occasion

Appendix C- Information sources

Statement of Opportunities, IMO document, July 2010

- Load forecasts
- List of current generating assets
- Planned generation

Balancing Support, IMO paper, 23 November 2010

- Raw data showing by trading period the advantage from IPPs' STEM offers being used for balancing for 2009/2010

2010 Margin Peak and Margin Offpeak Review, Final report to IMO, SKM-MMA, 17 November 2010

- Properties of existing generators table

IMO website (by trading period)

- STEM and MCAP
- Balancing volumes
- Load forecast

Other information

- SCADA data for all generators for 2009-2010

Other documents consulted:

Valuing the Capacity of intermittent Generation in the South-West Interconnected System of Western Australia, MMA Confidential Report to the IMO, 29 January 2010

Scenarios for Modelling Renewable Generation in the SWIS, ROAM report to the IMO, 25 August 2010

Economic Evaluation of Cycling Plants, Siemens Reference Power Plants, H. Emberger, Dr D. Hoffman, C. Kolik, 2007

The Cost of Cycling Coal Fired Power Plants, Steven A. Lefton, Power Plant O&M and Asset Optimisation, 2006

Development of balancing in the Internal Electricity Market in Europe, K Verhaegen, L. Meeus, and R. Belmans, Electrotechnical Department ESAT-ELECTA, 2006

Gas prices in Western Australia – Review of inputs to the WA Wholesale Energy Market, ACIL Tasman, prepared for the IMO, May 2010

Balancing price formation, IMO paper, 2 November 2010