Independent Market Operator

Reserve Capacity Mechanism Working Group (RCMWG)

Agenda

Meeting No.	3
Location:	IMO Board Room, Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Tuesday 17 April 2012
Time:	Commencing at 2.00 to 5.00pm

Item	Subject	Responsible	Time
1.	**WELCOME**	**Chair**	2 min
2.	**APOLOGIES / ATTENDANCE**	**Chair**	2 min
3.	**MINUTES ARISING FROM MEETING 2**	**Chair**	10 min
4.	**ACTIONS ARISING**	**Chair**	10 min
5.	**PRESENTATION: Harmonisation of Demand Side and Supply Side Capacity Resources**	**Dr Richard Tooth Sapere Research Group**	90 min
6.	**PRESENTATION: RCM Review Report 2**	**Mr Mike Thomas The Lantau Group**	30 min
7.	**GENERAL BUSINESS**	**Chair**	10 min

Independent Market Operator

Reserve Capacity Mechanism Working Group

Minutes

Meeting No.	2
Location:	IMO Boardroom Level 3, 197 St Georges Terrace, Perth
Date:	Tuesday 27 March 2012
Time:	Commencing at 2.00pm – 5.00pm

Attendees	
Allan Dawson	Chair
Suzanne Frame	IMO
Brendan Clarke	System Management
Andrew Sutherland	Market Generator
Ben Tan	Market Generator
Shane Cremin	Market Generator (Via phone)
Brad Huppatz	Market Generator (Verve Energy)
Amanda Rudd	Market Customer (Proxy)
Patrick Peake	Market Customer
Steve Gould	Market Customer
Stephen MacLean	Market Customer (Synergy)
Andrew Stevens	Market Customer/Generator
Jeff Renaud	Demand Side Management
Geoff Down	Contestable Customer
Justin Payne	Contestable Customer
Paul Hynch	Observer (Office of Energy)
Wana Yang	Observer (Economic Regulation Authority)
Additional Attendees	
Mike Thomas (The Lantau Group)	Presenter
Aditi Varma	Minutes
Fiona Edmonds	Observer
Jenny Laidlaw	Observer
Greg Ruthven	Observer
Apologies	
Corey Dykstra	Market Customer

Item	Subject	Action
1.	**WELCOME AND APOLOGIES / ATTENDANCE** The Chair opened the second meeting of the Reserve Capacity Mechanism (RCM) Working Group (RCMWG) at 2:05pm. The Chair welcomed the members in attendance and noted apologies received from Mr Corey Dykstra prior to the meeting. The Chair acknowledged Ms Amanda Rudd as a proxy for Mr Dykstra and Mr Shane Cremin linked via phone. The Chair also introduced Mr Mike Thomas from The Lantau Group.	
2.	**MINUTES ARISING FROM MEETING 1** The following changes were noted on page 8: • Mr Huppatz noted that ~~keeping~~ a discussion on the classification of Outages ~~in the out-of-scope list would limit the amount of attention given to~~ should have been included as a part of the scope of the dynamic refund regime. There was discussion among RCMWG members regarding the level of detail required in the recording of minutes. RCMWG members decided that it was important to retain some level of detail relating to the reasoning behind decisions taken and the various topics raised in discussions.	
3.	**ACTIONS ARISING** The Chair noted that all action points from the previous meeting had been completed.	
4.	**PRESENTATION ON RCM OPTIONS DISCUSSION FOR THE RCMWG: MR MIKE THOMAS, THE LANTAU GROUP** The Chair invited Mr Mike Thomas to present his paper on the over-supply of capacity in the Wholesale Electricity Market (WEM). The following points of discussion were noted: • Mr Stephen MacLean queried Mr Thomas's opinion on the consistency of a market-based approach with the administrative features of WEM. Mr Thomas responded that it was important to assess the level of governance in WEM. He also noted that WEM was similar to the Singapore market because of its administrative nature. • Mr Andrew Stevens noted that in the event of excess capacity, retailers are faced with increased costs in the form of an increased Shared Reserve Capacity cost. Discussion ensued amongst RCMWG members over how costs of excess capacity were shared in the market. Mr Thomas concluded that the key point was that the excess reserve capacity had to be paid for in some way by Market Participants. • Mr Thomas commented that the solution to the problem of excess capacity should not be such that it removes today's problem of excess only to create tomorrow's problem of shortage. Mr MacLean noted that the current market design may have the potential for future shortages in reserve capacity.	

Item	Subject	Action
	The Chair highlighted that in 2008-09, the market faced shortages and the IMO procured Supplementary Reserve Capacity (SRC). • Mr Thomas talked about the analysis on the indicative value of lost load. He noted that the analysis showed that the difference between the administrative value and the economic value of capacity credits was high. On this point, Mr Huppatz noted that the Planning Criterion is not only based on the probability of exceedence, the market also places high value on unserved energy. Mr Thomas acknowledged that the current analysis did not delve deeper into that issue. However, he noted that the issue around value creation in a few number of hours remained. • On the issue of excess capacity, Mr Sutherland highlighted that it was important for the group to understand the make-up of the capacity surpluses. Mr Stevens and Mr MacLean noted that this was an important question to consider. Mr Thomas observed that in a pure market-based mechanism, it is never possible to know what caused the problem and only the effects are visible. Mr Peake noted that in a market-based scenario, older, inefficient plants might be retired whereas in RCM, older plants continued to produce power. Mr Thomas noted this point. He added that the causes of excess capacity could potentially change in the future and therefore, it would be more useful to think of the problem as active or passive behaviour of participants. Active behaviour is characterized as participants actively making commercial decisions in the market and passive behaviour is characterized as participants' exposure to decisions made by other stakeholders. • Discussion ensued on uncontracted Capacity Credits. Mr Sutherland mentioned that large OCGT plants do not generally rely on the RCM to be built because they have large capital costs. In his opinion, a lot of the uncontracted Capacity Credits present in the market might be supplied by projects with low capital costs or low debt-to-equity ratios. He added that retailers would prefer contracting for the long term to match their capacity requirements. He also observed that there are potentially other hedges working outside of the RCM. Mr MacLean added that retailers are also concerned with volatility in the market and their preference is to hedge their risks by locking in contracts. He added that retailers would prefer to contract to meet their energy requirements and would contract for capacity only if they perceive a discount was being offered on the prevailing Reserve Capacity Price (RCP). However, the RCM offered generators a higher expected price. Mr Peake added that the volatility in the RCP has made participants contract outside the market. Mr Sutherland added that the RCP is a blunt instrument as it tends to attract capacity that can be offered by projects that have low capital costs. Mr MacLean suggested that the Maximum Reserve Capacity Price (MRCP) should be sensitive to the type of capacity that the market needs at a given time. Mr Cremin observed that the market would buy energy if it is needed irrespective of the RCM. He noted that it should only be the peak capacity on which an administrative control might be needed. • Mr Thomas proceeded to talk about the five-yearly MRCP review. He further discussed the corrective action that could be	

Item	Subject	Action
	taken to discourage excess capacity. He mentioned that the RCP setting process did not allow for the RCP to adjust enough in response to excess capacity in the market. Mr MacLean queried if the purpose of the adjustment was to only discourage excess capacity or also to act as an administrative method to create an efficient price that could be received in an auction. Mr Thomas responded that the RCP did not have any connection with a reserve capacity auction outcome. Mr Shane Cremin noted that the adjustment mechanism was not only to discourage excess capacity but also to encourage bilateral contracting. Mr Tan observed that a problem with increasing the slope of the sliding scale was that it would perversely incentivise retailers to increase capacity because the book value of a capacity credit may decrease. This implied that the sliding scale would need a floor price to stop a massive injection of capacity in the market. Mr Sutherland argued that the sliding scale would imply that more expensive capacity such as those supplied by coal fired plants or combined cycle plants would get priced out of the market till only DSM capacity was left as the cheapest option. • Mr Thomas proceeded to present his recommendations on the excess capacity adjustment slope. Mr Thomas added that preference should be given to adjusting the RCM in ways that could make it more consistent with market-based outcomes rather than considering a replacement of the current mechanism. Mr MacLean noted that he had been working on an option that would not be a complete overhaul of the market but would still be closer to a market based mechanism. Mr Peake mentioned that it was important to consider that a shortfall of capacity would be less acceptable than excess. Mr Sutherland mentioned that it is difficult to fine-tune the mechanism without knowing the cause and effect. Mr Thomas responded that market mechanisms always work in information asymmetry where exact causes are not known and market players tweak their decisions and then assess the consequences • Mr Thomas also presented a spigot-control mechanism as an alternative solution to the excess capacity issue. The Chair mentioned that a spigot control mechanism creates barriers for new technologies to enter the market. He added that perverse behaviours like not voluntarily decommissioning old plants would be incentivised. Mr Peake added that such a mechanism could also create situations where peaking generators could drive out generators that have low fuel costs. This would then flow to the energy market in terms of higher prices. • Mr Sutherland argued that the same issue existed with the steep sliding scale. If too much excess capacity existed in the market then projects with large capital costs face high entry barriers. He added that low capital cost, high variable cost capacity is affecting the energy prices. Mr Thomas observed that a similar situation exists in Korea. Mr Huppatz and Mr Stevens argued that a steeper discount factor will create a distortion in the capacity market. Mr Sutherland argued that without a cap on the sliding scale, lower capital cost capacity like DSM would persist providing more capacity as long as the price is high enough. • Mr Stevens argued that the most efficient outcome was only	

Item	Subject	Action
	possible if the proportion of baseload generation, mid-merit and peaking generation capacity existed in the shape of a pyramid. He argued that a higher percentage of DSM and peaking capacity in the market indicated inefficiencies. The Chair emphasized that the load profile in the SWIS was such that a healthy mix of plants was required. Mr Jeff Renaud added that DSM in WEM is almost at its saturation point. He noted that irrespective of the price, there was only a finite amount of demand response. Discussion ensued on the risks created by the sliding scale. Mr Peake noted that with a steeper sliding scale, risks to a large capital investment are increased but that does not necessarily mean that the technology would face entry barriers. Companies would look for a higher margin before investing in new projects. Mr Thomas noted that changing the risk profile is at the heart of the steep sliding scale. The idea is to discourage excess investment in harder to finance projects as well as undermine investment in easily financed unnecessary projects. Mr Down noted that a variable price will also motivate contestable customers to consider changes to their capacity mix. He added that sustainable technologies will become more important. Mr Thomas acknowledged the importance of this point and added that this alternative adds a little more volatility to the market which will drive both generators and customers in the market to reconsider their positions. • Discussion ensued on the potential magnitude of impact of a shortage in capacity. The Chair reiterated that loss of load is a major cost to the market. • Mr Thomas concluded his presentation with a discussion on active and passive behaviours in the RCM and his recommendations. • The Chair reiterated the IMO Board's view that the RCM has provided benefit to the WEM since 2004. He noted that the WEM started with a shortage of capacity and has dealt with significant economic growth in Western Australia. The Board's perspective was that this mechanism should be adjusted rather than restructured to provide better economic incentives for existing and new capacity. • Mr Sutherland cautioned that the market could potentially become unattractive to investors given the recent MRCP reduction, the impending forecasting methodology review and peak demand reductions. The Chair noted that the RCMWG's advice may be to do nothing. However he observed that some ideas in Mr Thomas's recommendation would appear attractive and should be given adequate consideration. • The Chair concluded the discussion by inviting Mr Thomas to evaluate the concepts of a steeper sliding scale and expected value of capacity for the consideration of the RCMWG at its April meeting. Mr MacLean offered to provide details to the RCMWG on the topic of excess capacity costs to retailers. Mr Sutherland, Mr Payne and Mr Stevens asked if analysis could be provided on the composition of existing excess capacity. • Ms Yang noted that forecasting uncertainty is indispensable and that the last Statement of Opportunities (SOO) had shown a significant reduction in the load forecast. She noted that any discussion on the RCM should adequately consider the	

Item	Subject	Action
	reductions introduced by the SOO. *Action Points:* • *The IMO to conduct analysis on the composition of excess capacity in the RCM and provide updates at the April RCMWG meeting.* • *Mr Thomas to conduct further analysis on his recommendations for the RCM and provide updates at the April RCMWG meeting.* • *Mr MacLean to circulate his analysis on costs of excess capacity to the market among RCMWG members.*	**IMO** **Mr Thomas** **Mr MacLean**
5	**PROPOSED SCHEDULE OF WORK FOR RCMWG** The Chair noted some participants had requested that the timing of the discussion on the alignment of a dynamic reserve capacity refund regime should be brought forward and lengthened to about 5 months. The Chair noted that the IMO will endeavour to accommodate this request. However, he mentioned that the plan for the next RCMWG meeting was already finalised and it would include Dr Tooth's presentation on harmonisation of DSM with generation capacity. He also noted that Mr Thomas would be invited to the next meeting to elaborate his ideas further. *Action Point:* • *The IMO to reissue the proposed work schedule for RCMWG with the changed timing for the discussion on the Dynamic Refund regime.* • *The IMO to invite Mr Thomas to April RCMWG meeting.*	**IMO** **IMO**
6	**CLOSED** The Chair thanked all members for attending and declared the meeting closed at 5.05 pm.	

Independent Market Operator

Reserve Capacity Mechanism Working Group (RCMWG)

Agenda item 4: RCMWG Action Points

Legend:

Shaded	Shaded action points are actions that have been completed since the last RCMWG meeting.
Unshaded	Unshaded action points are still being progressed.

#	Action	Responsibility	Meeting arising	Status/Progress
1	The IMO to incorporate agreed changes and publish Meeting 1 minutes as final	IMO	March	Completed
2	The IMO to conduct analysis on the composition of excess capacity in the RCM and provide updates at the April RCMWG meeting.	IMO	March	Completed
3	The IMO to reissue the proposed work schedule for RCMWG with the changed timing for the discussion on the Dynamic Refund regime.	IMO	March	Completed- See attached
4	The IMO to invite Mr Thomas to April RCMWG meeting.	IMO	March	Completed
5	Mr Thomas to conduct further analysis on his recommendations for the RCM and provide updates at the April RCMWG meeting.	Mr Mike Thomas	March	Completed

#	Action	Responsibility	Meeting arising	Status/Progress
6	Mr MacLean to circulate his analysis on costs of excess capacity to the market among RCMWG members.	Mr Stephen MacLean	March	Completed

Revised Schedule for RCM WG Scope of Works

Issue	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
Oversupply of Capacity in the WEM, Pricing of Capacity in Oversupply Conditions and Additional Costs Imposed on the Market									
Role of DSM in the RCM, and the Fuel Requirements Imposed on Generation Capacity Providers									
The Alignment of the Implementation of a Dynamic Reserve Capacity Refund Regime									
The Allocation of Capacity Costs to Market Customers (IRCR)									
The Impact of Forecasting Inaccuracy on the RCM									
Timeline and Scope for a Periodic Review of the RCM									

NB: Timing of issue discussion is subject to change depending on progress

PRIVILEGED AND CONFIDENTIAL

Report for the Independent Market Operator

Performance requirements for demand-side and supply-side capacity resources DRAFT

Dr Richard Tooth

April 2012

sapere research group

About the Author

Dr Richard Tooth is a Director with the Sydney office of Sapere Research Group. He works on public policy, competition and regulatory issues across a number of industries including water, energy, transport and financial services. Dr Tooth has a PhD in Economics, a Master in Business Administration and a Bachelor of Science.

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.

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
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	

For information on this report please contact:

Name:	Dr Richard Tooth
Telephone:	02 9234 0216
Mobile:	0412 105 817
Email:	rtooth@srgexpert.com

Contents

Appendices

Glossary

DSM	Demand Side Management
DSP	Demand side programme
FERC	The US Federal Energy Regulatory Commission
IRCR	Individual reserve capacity requirement
LOLP	Loss of load probability
MWh	Megawatt hour
PJM	PJM Interconnection LLC, a Regional Transmission Organization (RTO) in the eastern region of the United States
RCM	Reserve capacity mechanism
RCMWG	Reserve Capacity Mechanism Working Group
RCO	Reserve capacity obligation
SRAC	Short run average cost.
STEM	Short Term Energy Market
SWIS	South West interconnected system
WEM	Wholesale Electricity Market

1. Introduction

The Reserve Capacity Mechanism (RCM) is a mechanism to support the Wholesale Electricity Market (WEM) in the South West interconnected system (SWIS) in ensuring there is sufficient reserve capacity to meet reliability targets. The RCM allows for capacity to be provided by generation resources (predominantly thermal generators) or through reductions in demand, known as Demand Side Management (DSM).

The Reserve Capacity Mechanism Working Group (RCMWG) has been established to assess the issues highlighted by The Lantau Group in its report "*Review of RCM: Issues and Recommendations*" (hereafter the Lantau Report).[1]

Two issues and related recommendations raised in the Lantau Report refer to the performance requirements for Reserve Capacity. The issues and related recommendations are:

- The role of DSM in the RCM

  Recommendation: The Lantau Group suggests harmonising the treatment of demand-side and supply-side (generation resources) by increasing the minimum availability requirement for Demand Side Programmes

- The fuel requirements imposed on generation capacity providers

  Recommendation The Lantau Group suggests refinement of the fuel supply requirement

This paper examines the role of peaking capacity in the market, explores current issues within the WEM and presents some preliminary options for discussion. In the process of the review a number of related issues have been identified. These have been noted but are not discussed at this time.

---

1 This review is one of a number of work streams established (or being considered) to review the issues associated with the RCM that were identified by The Lantau Group. The RCMWG is also considering:

- The issues that impact surplus capacity
- The allocation of capacity costs to Market Customers (Individual Reserve Capacity Requirements)
- The impact of forecasting inaccuracy on the RCM

Furthermore during 2012, the Planning Criterion and the methodology for forecasting the Reserve Capacity Requirement will be subject to a 5 year review by the IMO.

2. Background

2.1 Harmonisation

The issues and recommendations raised in the Lantau Report reflect a concern that despite providing the same role in meeting peak demand requirements and being rewarded similarly, capacity resources are not always treated consistently in the WEM.

All capacity resources provide the same basic function in providing capacity when required and subject to testing and certification, Capacity Credits are assigned to capacity resources and availability classes equally; that is DSM capacity is valued the same as generation capacity (1 MW of DSM = 1 Capacity Credit = 1 MW of generation).

However, currently the Market Rules allow for differences in the treatment of DSM and generation resources. A difference in the treatment of capacity resources is important *if* it discriminates against, or favours, some resources and leads to inefficient investment. This would be contrary to Market Objectives that encourage economically efficient and reliable production and supply and potentially the Market Objective to avoid discrimination (see Market Objectives in Box 3 in the Appendix).

Performance requirements have a role in ensuring that there is consistency in the value provided and that the capacity provided aligns with the needs for capacity. Performance requirements can directly modify the value a set of resources provides by changing their characteristics (e.g. availability) or providing a barrier (when coupled with compliance) to prevent certification of capacity that does not meet the requirements.

A second concern reflected in the Lantau Report is that performance requirements for some capacity resources may be inefficient and/or overly complex. Performance requirements can directly impact on the efficiency of providing a resource to the market.. Requirements that are unnecessarily strict can discourage efficient investment and potentially discriminate against particular technologies.

2.2 Current performance requirements

The performance requirements for DSM and Scheduled Generators vary significantly. DSM providers may nominate a number of availability restrictions (subject to limits) including the maximum hours used, the duration period, and the notice period (see Box 1 below). In effect these limitations have meant that many DSM resources are available for as little as 24 hours in a Capacity Year. Some concerns have been raised that the restrictions on the availability of DSM for dispatch are inefficient and detract from the value that DSM can provide to the WEM – these concerns are elaborated in Section 3 below.

In contrast Scheduled Generators must always be available for dispatch unless undertaking a Planned Outage, and must demonstrate that they have fuel arrangements to allow them to supply generation continuously during the Peak Trading Intervals between 8am to 10pm on Business Days (see Box 2 below). Concerns have been raised that this requirement is unnecessarily onerous for some types of peaking generation providers and may provide a deterrent to investment and distort other operational decisions. These concerns are elaborated in Section 4 below.

Box 1: Performance requirements of DSM

DSM providers may nominate availability restrictions under clause 4.10.1(f), which include:

- Maximum hours per year (must be >= 24)
- Maximum hours per day (must be >= 4)
- Maximum number of dispatch events per year (must be >=6)
- Minimum notice period for dispatch (must be <= 4 hours)
- The hours in which the facility is available (must include 12-8pm on all business days)

Under clause 4.12.8 a Demand Side Programme which has been dispatched to a level equivalent to its Reserve Capacity Obligation Quantity for two consecutive days may be dispatched for the third day by System Management but will not be subject to capacity refunds if declares itself unavailable or fails to perform.

Box 2: Performance requirements for Scheduled Generators

The fuel requirements that are placed on Scheduled Generators stems from Market Rule 4.11.1 (a) which states:

> [...] the Certified Reserve Capacity for a Scheduled Generator for a Reserve Capacity Cycle must not exceed the IMO's reasonable expectation of the amount of capacity likely to be available, after netting off capacity required to serve Intermittent Loads, embedded loads and Parasitic Loads, for Peak Trading Intervals on Business Days [...] assuming an ambient temperature of 41^{O} C;

Where, in Chapter 11 of the Market Rules, a Peak Trading Interval is defined as 'A Trading Interval occurring between 8 AM and 10 PM'.

The application of this requires that facilities must demonstrate that fuel storage, supply and transport arrangements are sufficient to allow 14 hours of continuous operation.

2.3 The value of capacity resources

From the viewpoint of efficiency, we are concerned with ensuring compensation reflects the *marginal* value of a resource. Thus, while a base-load generator may provide capacity over longer periods than a peaking generator the marginal contribution may be identical given the existence of other resources.

The marginal value of a resource is the marginal contribution it provides to the load carrying capability of the system given the existence of other resources.[2] This value reflects how the resource helps to meet the reliability criteria. Because currently the dominant reliability criterion relates to peak demand, the marginal value of capacity resources primarily relates to their availability during very peak times.

The load to be served (and thus the need for capacity) varies substantially over time. The load duration curve (LDC) for the SWIS is characterised by sharp summer peaks. As such, while some capacity is required at all times, higher levels of capacity are only required for a small number of Trading Intervals. For 2010/11 (See the LDC in Figure 2 in the Appendix) the top 5 percent of maximum capacity used was required for around 24 hours in the year and more than 10 percent of maximum capacity used was required for less than 96 hours. The timing of the peak capacity requirements is also reasonably predictable. In each of the 2007/08 to 2010/11 years, the peak was reached on a February weekday between 3 pm and 5pm. In each of the years, all of the top 150 Trading Intervals fell in January, February or March between 9am and 9:30pm.

The marginal value of a capacity resource also depends on other factors including:

- The availability and limitations in the use of the resource.
- The penetration of like resources — due to common limitations the marginal value of a resource tends to decline with greater penetration of like resources.
- The nature of risks to reliability.

.

2 A useful measure of marginal reliability value is the effective load carrying capability (ELCC). This is a measure of the additional load that the system can supply with the particular resource, with *no net change in reliability*. A similar measure is Equivalent Firm Capacity (EFC) which measures the capacity of a benchmark generator that would deliver the same reduction in risk.

3. Demand Side Management

3.1 The nature and role of DSM

DSM providers provide capacity by committing to reducing demand by a guaranteed level[3] on dispatch. [4] While different in mode of operation, DSM serves an identical function to other resources in meeting the peak demand. DSM is acquired through the RCM using the same process as for Scheduled Generation. Dispatch is also largely similar to Scheduled Generators, involving application of a pre-defined merit order,[5] payments on dispatch and the application of capacity refunds for being unavailable when required[6].

There are some inherent differences. DSM is relatively expensive to dispatch — the cost of dispatching DSM includes the opportunity cost to the participating loads of reducing their consumption which for many loads can be significant.[7] Due to the high cost of dispatch, it is efficient for DSM to be last on the dispatch merit order.

DSM capacity is more flexible than other resources – additional capacity can be developed relatively quickly, in small increments and does not involve substantial investment by participating loads. In contrast, increasing Scheduled Generation capacity can be very expensive, time consuming and involve substantial sunk costs. Because DSM can be acquired quickly, DSM has a role in addressing shortages when additional capacity needs to be acquired quickly.

The underlying heterogeneity (variation) of DSM loads is large. The DSM loads are provided by a very large mix of customers of energy of different sizes, needs and locations. This diversity, along with the ability to oversubscribe loads to a Demand Side Programme, helps to minimise the risk associated with some DSM loads being not available.

---

3 There are other types of DSM used in other systems include programs where consumers reduce demand to a fixed level and programs whereby customers voluntary reduce demand during emergencies in exchange for a dispatch payment.

4 The reduction is measured against Relevant Demand, a pre-determined baseline that is intended to reflect the normal operating level when dispatch is likely. There has been substantial consideration of the method for determining Relevant Demand. See Rule Changes RC_2010_29. Consideration of Relevant Demand is out of scope of this review.

5 There are however some slight differences, under both the current market and new Balancing Market scheduled to commence in July 2012. Most notably the availability and response of DSM cannot (at present) be monitored in real-time by System Management.

6 Following the implementation of RC_2010_29, Demand Side Programmes must make capacity refunds during any Trading Interval where they have not associated sufficient loads with their programmes to meet their obligations (i.e. there is a shortfall in what they could provide to the market) and during Trading Intervals where they have a positive Reserve Capacity Obligation Quantity and fail to respond adequately to a Dispatch Instruction.

7 Their high cost to be dispatched is consistent with (anecdotal) reports that, with rare exception, DSM providers bid in at the maximum bid prices for dispatch.

There are a number of advantages and disadvantages in DSM in terms of its contribution to reliability and it would be premature to comment on its relative value. Some of the relevant factors include *inter alia*:

- DSM use is subject to limitations nominated by the DSM providers (as is discussed in this paper).
- DSM is largely un-reliant on fuel resources — thus DSM has particular value in managing reliability during a disruption to fuel supplies. This benefit was reflected in the successful use of DSM in February 2011 in maintaining reliability during a High Risk Operating State caused by a gas supply disruption. Similarly DSM is not subject to risk from transmission failure (and also does not experience transmission losses).
- More generally DSM adds to the diversity in capacity resources in the WEM.
- DSM does not experience forced outages in the same way as generation facilities. While, like Scheduled Generators, DSM providers may declare themselves unavailable, the rate and causes of unavailability differ to Scheduled Generators. The unavailability of DSM may be related to environmental conditions. For example, a Demand Side Programme that represents a single load may be unavailable if a back-up generator associated with that load has failed. Similarly the willingness to provide DSM (e.g. by an industrial customer) may vary with economic conditions. Conversely, DSM aggregators work to ensure that they have a portfolio to manage the risk of unavailability by oversubscribing loads.

3.2 DSM availability and issues

While the specific restrictions vary, the practice of applying limitations to DSM is consistent with other systems. However, relative to comparable programs elsewhere, the minimum availability requirements associated with DSM in the SWIS appear light (A comparison with some similar programs in North America is shown in Table 2 in the Appendix). While the minimum duration of dispatch (4 hours) is comparable with many other systems (but smaller than that used in PJM) the total availability tends to be less.

In the SWIS the minimum total availability for DSM is 24 hours. In contrast the most restrictive PJM program allows for 10 interruptions each of up to 6 hours duration. The ERCOT program is more restrictive; it is only for 2 deployments (up-to 8 hours) per 4 month period but is for only resources that can be dispatched with 10 minute notice. However, ERCOT is considering modifying the requirements to increase the 10 minute notice period and enable renewing of obligations.

Lack of use of higher-availability classes

A notable concern with DSM is that it is not being used as intended. As shown in Table 1 below, the Capacity Credits awarded to DSM have migrated to the lowest availability class.

The lack of participation in the higher availability classes has been attributed to a lack of incentive to participate in these classes. DSM participants in the lowest availability class receive the same rewards as the higher-availability class and are at lower risk of being dispatched more often.

Table 1: Resource by class

	Capacity credits by year							
	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Class1, Generators	3,633	3,984	4,481	5,055	5,125	5,233	5,586	5,587
Class2, 72-96 hrs	-	-	8	-	17	-	-	-
Class3, 48-72 hrs	111	131	81	-	-	108	20	43
Class4, 24-48 hrs	-	-	30	82	117	152	389	457
Total	**3,744**	**4,115**	**4,600**	**5,136**	**5,259**	**5,493**	**5,996**	**6,087**
DSM penetration	3.0%	3.2%	2.6%	1.6%	2.5%	4.7%	6.8%	8.2%

A lack of participation in the higher-availability classes is of concern. There is a risk that much of the potential value of available DSM resources is being wasted due to inadequate incentives to provide greater availability. Limitations on the number of hours of use are of concern for two reasons.

- First, there is a risk that the limits bind and DSM cannot be dispatched when needed. This is of particular concern because, due to correlations in weather patterns and others factors, if DSM is used it may be required several times during the one summer.
- Second, System Management may be hesitant to dispatch DSM early in a summer because of concerns that availability will be limited later when more required.

It appears likely that much of the existing DSM resource could be made more available. As shown in the above table, there was a much greater participation in the higher availability classes in previous years.[8] Anecdotal feedback received in the course of this review included that many customers would be able to provide a higher availability resource if required. Some customers would have significant ability to provide additional capacity. For example, industrial customers with back-up generation may be capable of providing a very high level of availability.

Limitations on use

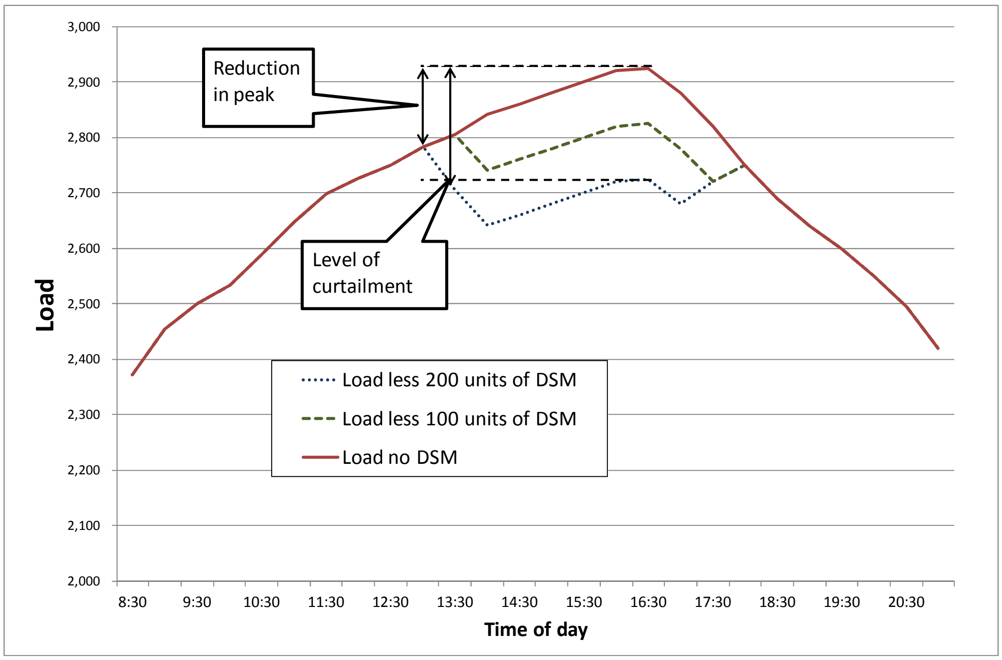
Limitations on use of a capacity resource will not have an impact on the value of the resource if the limitations do not coincide with peaks when capacity is required. However,

8 Anecdotal feedback has been that there was a shift to lower-availability classes as customers realised there was no incentive nominating a higher level of availability.

there is a risk that as more of the limited resource is used, the peaks will shift to periods which are not easily covered by the resource.

An illustrative example of this effect caused by a maximum duration limit is shown in Figure 1 below. In the example, when DSM curtailment is 200 MWs, due to limits on the maximum duration the peak load is shifted to the shoulders with the effect the peak reduction is less the amount of DSM curtailed.[9] When a smaller of amount of DSM used (100 MWs in this example) the reduction in the peak is equivalent to the DSM curtailment.[10]

Figure 1: DSM curtailment – illustrative example.



The penetration level of DSM at which saturation become a factor is unclear. The Capacity Credits awarded in 2013/14 to Class 4 (457 MW from Table 1 above) are significantly less than the 'Capacity associated with Availability Class 4' contained in the Availability Curve (909 MW from Table 3 in Appendix 2). However, the analysis used to determine the later amount does not incorporate consideration of all limitations.

This issue of saturation has been recognised by PJM. PJM periodically conducts a saturation analysis of its DSM programs incorporating consideration of the maximum duration and the maximum number of interruptions allowed.[11]

---

9 DSM could be overlayed to cover the shifting peaks, however this would involve additional DSM.

10 Examples of this peak-shifting occurred during the use of DSM on February 2011 during the period of the Varanus Island gas disruption.

11 The analysis PJM conducts reflects the situation for a fixed quantity of capacity whereby DSM displaces other capacity.

Other limitations on the use of DSM can also be important and increase in significance with greater levels of penetration. In addition to availability and maximum duration limitations other notable limitations of DSM are that a DSM provider:

- can specify that its use is limited to 12-8pm on Business Days;
- can specify a minimum notice period of up-to 4 hours; and[12]
- if scheduled for a third consecutive day, can opt not to provide without penalty (the 'three-day rule').

Another issue is the timing of DSM. To manage the highest peak load DSM should be dispatched so that it layers over the peak. Limitations such as those relating to the notice period may hamper System Management's ability to time the use of DSM when there is uncertainty associated with demand and supply (e.g. Intermittent Generators).[13]

3.3 Other considerations

There are financial issues with DSM that, although not directly within scope, are closely related to this scope of this review.

Dispatch payments for DSM impose a cost on other participants

Scheduled Generators are paid for the energy they provide by Market Customers receiving the energy. The price paid is determined by the energy and balancing markets which is designed to encourage efficient ordering and pricing at the marginal cost of provision.

However, the dispatch of DSM imposes external costs on others. DSM providers receive additional payments when dispatched, which are funded by charges on Market Participants.

These funding arrangements will not have an impact on efficiency in the short-term as they do not impact on the merit order of resources being scheduled. In the long-run they could provide a bias towards DSM, however, the significance would be slight given the small amounts paid in DSM dispatch. Nevertheless the dispatch payments may be viewed as counter to the objective of harmonising the value of capacity resources.

The issue of dispatch payments for DSM has received considerable attention in North America, where it was the subject of recent ruling by the Federal Energy Regulatory Commission (FERC).[14]

---

12 The notification period also tends to be more generous for DSM in the SWIS. Whereas in SWIS the maximum notification period is 4 hours, 2 hours is the norm elsewhere.

13 The effect of DSM use on the 26 February 2011 provides a potential example. On this day, the use of DSM reduced the peak load by the amount of curtailed load. However, the dispatch of DSM coincided with a greater output from Intermittent Generators with the effect that the reduction in the peak use of Scheduled Generators was much less.

14 See FERC (2011). The final ruling came down in favour of compensating demand response an equivalent amount to that of dispatching generator. This approach has been heavily criticised. See, for example, Hogan (2010).

3.4 Options for harmonising the treatment of the DSM capacity with generation capacity

Two broad options for modifications to DSM performance requirements are presented below. These are just presented for discussion – other options are feasible.[15]

D1 Modify minimum availability requirements

Concerns over the low-availability of DSM might be simply addressed by increasing the minimum availability requirements for DSM. This would result in an increase in the value of the DSM resources that are provided but may result in a reduction in the amount of DSM that is offered to the market.[16]

The impact on the value of DSM capacity is closely related to the amount of DSM and other capacity in the market. The impact on the relative value of DSM would depend on the saturation of low-availability DSM. If there is an excess of low-availability DSM, then an increase in minimum availability would have limited cost (in terms of lost DSM) and have some benefit in increasing the value of the DSM that is presented.

The minimum availability criteria could most simply be increased by retiring one of the lower availability classes. Currently the higher DSM availability classes are not used. As such relative to the current practice there is little cost to amalgamating these classes.[17]

D2 Refine other DSM performance requirements

In addition to the minimum hours of availability, there are other performance requirements for DSM that may be made modified. For example, modifications may be made to:

- The maximum notification period allowed
- The maximum duration limit
- The periods during which DSM may be called
- The Capacity Refunds associated with failing to respond when DSM is called on a third consecutive day.

---

15 An alternative option employed by PJM is to regulate the amount of a limited availability DSM product but allow registration in higher availability products. A saturation analysis is undertaken to determine the amount of each product and an auction process use to allocation DSM between products.

16 The impact in the amount of DSM offered and the value may not be significant in the short-term. While there is surplus capacity, the likelihood of DSM being dispatched is low and the likelihood that the current minimum level of capacity is binding is very low. Thus an increase in the minimum availability would, by itself, likely have a negligible impact on the likelihood of DSM being dispatched and thus the disincentives for DSM loads providers to participate. There may be some short-term reaction as operations managers at DSM load provider sites may consider that, despite the low likelihood of being dispatched, they need to prepare for a higher level of availability.

17 An alternative option considered but not included is to retire the classes not used. While there would be little cost to doing so, the benefits would be light; primarily relating to simplicity of administration.

The issues and implications are similar to increasing the minimum availability, however there are some differences. The short-term effects of changing some of the above criteria may be significant for some providers. Changing some requirements may effectively prohibit some DSM loads from participating. For example, an increase in the maximum duration limit or shortening of the notice period may be unacceptable for some customers.

The impact on value may also be more significant in the short-term. Modification of some of the above criteria could result in greater potential for DSM to be used during emergencies.

4. Fuel supply requirements

4.1 Issues

As noted above (in Box 2 on page 3) to receive Certified Reserve Capacity Scheduled Generators must demonstrate that their fuel storage, supply and transport arrangements are sufficient to allow 14 hours of continuous operation.

There is a concern that this requirement is unnecessarily onerous particularly for gas-fuelled peaking generators. As most gas is provided on a 'take or pay' basis, it is may be impractical to establish a contract that would ensure fuel supply is available in all circumstances when the facility is expected to run only occasionally. A risk is that this leads to some gas projects not proceeding and/or some generators opting to register as a liquid fuel operation and installing on-site fuel storage. A further concern is that in the event of a major disruption, external factors may affect liquid fuel re-supply arrangements.

The concerns that have been raised reflect the challenges in maintaining a balance in meeting the Market Objectives pertaining to efficiency and reliability.

- In the interests of reliability the IMO should only approve capacity that it reasonably expects will be available when required
- In the interests of efficiency the IMO should not avoid place onerous requirements on providers of capacity unless the benefits exceed the costs.

4.2 How much fuel is required?

The amount of fuel required to be supplied by a particular generator depends on the load requirements and the availability of other generation. If on a given day the load required to be met by generators was perfectly flat and there was no oversupply of generation, then every generator would be required to run continuously for the entire day. At the other extreme if a generator is just needed to supply the short period of time when there is an absolute peak the amount of fuel required would be minimal.

It commonly assumed there are sufficient commercial incentives in the energy market for base-load and mid-merit generators to meet the demand outside of Peak Trading Intervals. This is consistent with the Market Rules that define the periods between 8am and 10pm as Peak Trading Intervals, where additional supply is required. In such case, the role of performance requirements is contained to ensuring that generators are able to meet the incremental energy requirements during the daily peak.

However, this does not mean performance requirements should be set at 14 hours of continuous supply. First, demand during the peak Trading Intervals is not flat — it follows a reasonably consistent and predictable pattern with a peak around mid-afternoon. Peaking generators will share this burden. Second, like base-load plants, some (typically larger scale) peaking plants may have sufficient capacity and incentive to meet much of the 14 hours Peak Trading Interval period. As such, the peak that is left to be met by less rarely used plants may be much smaller.[18]

In 2010, McLennan Magasanik Associates (MMA) completed an analysis (MMA 2010) on the fuel requirements necessary for peaking generators. The analysis was based on application of a simulation model that examined under different scenarios how long each generator may be required. As a result of this analysis MMA concluded that the fuel requirements could be relaxed to allow for 12 hours continuous supply.

However the MMA analysis incorporated assumptions that would lead to a conservative fuel requirement. In particular the assumptions included that:

- peaking plants could only supply up to the limit imposed (i.e. if 12 hours was modelled then no peaking plants could exceed 12 hours) – in effect this limited the extent to which the larger lower-cost plants could alleviate the burden of smaller peaking plants.
- generators were dispatched with a strict merit order with higher cost plant not being used if a lower cost plants was available – in effect this limited the extent to which the higher cost plants could share the burden with other peaking plants.

4.3 Other issues and considerations

Other risks

The current interpretation of the performance requirements for Scheduled Generators focuses on the ability of a generator to have access to fuel to provide continuous supply over the course of a day.

There are however other relevant risks. For example the ability of a Facility to reliably supply in the event of fuel supply disruption and/or to continuously operate over a number of days may also be a consideration. In addition to a lack of fuel supplies there are other risks to reliable capacity resources that may be specific to the individual generators.

Commercial incentives

Generators have a number of existing commercial incentives to provide reliable supply. The combination of the market for energy, ancillary services and capacity refund payments provide incentives for many generators to provide capacity most of the time.

However these commercial incentives may be insufficient in some circumstances to take the necessary measures to achieve the appropriate level of reliability. This will be particularly the

18 The ratio of average use during the Peak Trading Intervals to the height of the peak during these periods gives an indication of the potential to share the load. If this ratio was 1:1 then if all the generators were required at the peak they would also be required for all other Peak Trading Intervals. The lower the ratio, the lower the average time that all generators need to be available. Based on load profiles from 2005/06 to 2010/11 the ratio reached at most 0.72 to 1 during stressed times (where surplus capacity was less than 800 MW). This suggests that if all the peaking generators required to meet the peak shared the burden equally, then they would be required to run at a little over 10 hours (0.72 x 14 hours) each.

case for high-cost generators (where the profit contribution from participating in the energy market is low) and in unusual circumstances, where the benefits of additional risk management may be small. If it is expensive to ensure availability for periods when the likelihood of being dispatched is low, then generators may not put in place sufficient measures to guarantee availability.

Thus the role of performance requirements for Scheduled Generators may be considered to supplement the existing commercial incentives where there is a concern that these incentives are insufficient to meet the IMO's reasonable expectation that a generator will supply capacity. Such unusual circumstances might include:

- When very infrequently used peaking generators are dispatched;
- When peaking generators are required for large use on a number of continuous days; and
- When there are fuel supply disruptions.

The plants that may be required for longer periods also have the greater commercial incentive to manage the risks to the fuel supply. As such, there is a risk that a large fuel requirement is:

- unnecessary for plants that are designed for frequent use; and
- binding and onerous for a plant designed to be used only at extreme peaks.

Other implications

The performance requirements of Scheduled Generators are used as the basis of assumptions regarding the availability of Scheduled Generators for undertaking an analysis of the risk to the unserved energy (USE) criterion. Any modifications to performance requirements would need to consider the impacts on the USE analysis required to be conducted by the IMO.

4.4 Options

Some broad options for modifications to performance requirements are presented below for discussion. These are presented to reflect a range for discussion and are not intended to be comprehensive – other options may be considered [19]

S1 No change or minimal change

The default option for fuel requirements is no change. The IMO would continue to require evidence of 14 hours continuous supply. This is a simple option, which may be justified on the basis that the issues associated with the current approach are not significant enough to warrant change.

[19] For example, a more substantial change might involve creating a separate lower availability class for Scheduled Generators whereby there are lower expectations on the extent of continuous availability and the periods of availability.

S2 Adjust the minimum availability requirement

Under this option a lower continuous supply requirement would apply that reflects that it is unlikely that 14 hours continuous supply would be required. An optimal level would need to be agreed. Potentially this option might be extended to incorporate other means by which Facilities share commitments for continuous supply as discussed in MMA (2010).

S3 Modify the commercial incentives to be available

An alternative to focussing on performance requirements is to place more weight on commercial incentives. A focus on commercial incentives could result in an increase in reliability and provide Scheduled Generators greater flexibility in how they manage the risks to reliability.

This option might be achieved through a modification to the capacity Refund Table that forms the financial implications of the failure to satisfy Reserve Capacity Obligations. Currently capacity refunds for Scheduled Generators are required anytime a generator is unable to supply and are only loosely related to the risk of an energy shortfall.[20]

The refund scheme could be restructured so that size of the refunds is more closely aligned with the times of greatest risk to reliability and give Scheduled Generators appropriate incentive to manage reliability risks.

There are few limits to this approach. Any change could be restructured such that ton average Scheduled Generators are no worse off. Potentially, penalty payments could be imposed — that is payments that are in excess of the Capacity Credit payments received, acknowledging the current restriction on the amount of refunds to the amount of Capacity Credits for generation and DSM resources via the Refund Table. This approach is akin to the implementation of a civil penalty associated with a breach of contract.

However, some care is required in modifying the scheme. There are costs in making the penalties too harsh as this can lead to an inefficient level of risk management (just as excessive fuel requirements could lead to an inefficient level of investment in redundancy). The penalties should not lead to higher cost of reliability than can be achieved by acquiring more capacity.

[20] The costs of not being available to provide capacity primarily exist when capacity is called upon and no other Generation resources are available. Should a capacity resource fail to supply and there is no other available Generation capacity there is a cost associated with dispatching DSM and a very large cost of an energy shortfall.

5. Summary

A summary of the options for discussion are presented below.

Option	Description
D1. Modify minimum availability	Increase the minimum hours that DSM is available. This could be achieved by retiring/amalgamating some DSM classes.
D2. Refine other DSM performance requirements.	Modify other performance requirements including the notification period, minimum duration and the ‘three day’ rule.

With regard to fuel requirements for supply side resources there are a number of options.

Option	Description
S1. No change or minimal change	This may be considered appropriate if tthe issues assoacited with the current approach are not considered to be significant enough to warrant change.
S2. Adopt a lower minimum availability requirement	This would require nominating an alternative (lower) fuel requirement that acknowledges that the current 14 hour requirement may be excessive, and adopting an approach that more closely aligns with the needs of the SWIS.
S3. Modify the commercial incentives to provide reliability	Restructure the financial implications of the failure to satisfy Reserve Capacity Obligations to more closely align Scheduled Generators incentives for reliability with what is required.

References

ACIL Tasman, 2011, 'Fuel availability for capacity credit certification, Implications of the proposed WEM rule change RC_2010_14', Prepared for ERM Power and Infrastructure Capital Group, 11 April 2011.

The Brattle Group, 2011, Demand Response Review: Presented to: AESO. March 2011, available from www.brattle.com/_documents/UploadLibrary/Upload937.pdf

FERC (Federal Energy Regulatory Commission), 2011, 'Demand Response Compensation in Organized Wholesale Energy Markets', Final Rule, Docket No. RM10-17-000, Issued March 15, 2011.

Hogan, William, 2010, 'Demand Response Pricing in Organized Wholesale Markets', paper prepared for Prepared for ISO/RTO Council, 13 May 2010.

Lantau Group, 2012, "*Review of RCM: Issues and Recommendations*".

MMA (McLennan Magasanik Associates), 2010, Fuel Capacity Requirements to Meet System Reliability in the SWIS, April 2010.

PJM 2010, Resource Adequacy Planning Department , 'Demand resource saturation analysis', May 2010.

Appendix 1 Market Objectives

Box 3: Market Objectives

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

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

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

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

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

Appendix 2 Additional charts & tables

Figure 2: Load Duration Curve for year ending March 2011.

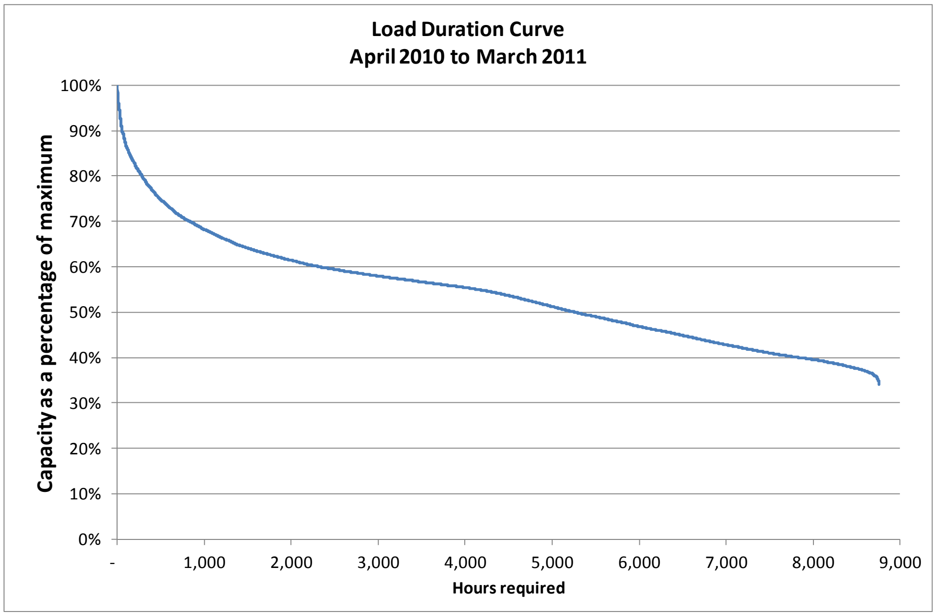


Table 2: Availability requirements of comparable programmes

System	Availability
SWIS – DSM	Minimum 24 hours in total. Minimum 4 hours interruption
PJM - Limited DR Extended Summer DR & Annual DR	Up to 10 interruptions each of minimum 6 hours Unlimited interruptions each of up to 10 hours duration
ISO NY (New York) – Special case resource	No limit on number of interruptions. Minimum 4 hours per interruption.
ISO – NE (New England)	No limit on number of interruptions. Minimum 2 hours per interruption
MISO	Minimum 4 hours interruption, at least up to5 times per year
IESO (Ontario), DR3 Program	Up to either 100 hours or 200 hours per year.
ERCOT – EILS program	Maximum of 2 deployments (or 8 hours) per (4 month) Contract Period. Under review.

Source: See Appendix 3

Table 3: Availability Curve

Availability Curve Information	2012/13 (MW)	2013/14 (MW)	2014/15(MW)
Market Rule 4.5.12(a):			
Capacity required for more than 24 Hours	4209	4390	4806
Capacity required for more than 48 Hours	4116	4280	4694
Capacity required for more than 72 Hours	4041	4202	4631
Capacity required for more than 96 Hours	4004	4149	4590
Market Rule 4.5.12(b):			
Minimum Generation Required	4280	4402	4828
Market Rule 4.5.12(c):			
Capacity associated with Availability Class 1	4280	4402	4828
Capacity associated with Availability Class 2	0	0	0
Capacity associated with Availability Class 3	0	0	0
Capacity associated with Availability Class 4	842	909	945

Appendix 3 DSM programs in other jurisdictions

This appendix includes details of programs by Independent System Operator (ISOs) and Regional Transmission Organizations (RTOs) in North America that are similar to DSM in the SWIS.

The programs go by a variety of names and are often complemented by a range of Demand Resource programs. Unless otherwise noted, the descriptions relate only to programs which involve a demand resource receiving a capacity credit and in return committing to reduce demand when called.

Some recent comparison of programs can be found in The Brattle Group (2011).

ERCOT (Texas)

ERCOT introduced Emergency Interruptible Load Service (EILS) in 2008. Key requirements include:

- EILS Resources are subject to a maximum of 2 deployments (or 8 hours) per Contract Period (4 months) and once per day
- EILS Resources must shed at least 95% of committed load within 10 minutes of of the instruction.

ERCOT is considering modifying the requirements to increase the 10 minute notice period and allowing renewal of obligations to obtain additional hours if ERCOT exceeds the eight-hour obligation within a contract period.[21]

IESO (Ontario)[22]

The IESO operates a DR3 Program in which participants must be available in a period that encompasses approximately 1,600 hours/year and must have selected to participate in one of two of the pre-defined schedules.

- Participants can select activations of up to either 100 hours or 200 hours per year.
- Each activation is for 4 hours.

ISO-NE (New England)

ISO – NE offer five different products: Real-time Demand Response, Real-time Emergency Generation, Critical Peak, On Peak and Seasonal Peak.

- Each type has its specific obligations, but all Demand-Side programs must both offer and deliver capacity in all 12 months of the year.
- Minimum dispatch duration is 2 hours

[21] Source: Mark Watson, 'ERCOT proposed demand-response rule changes draw mixed reviews', 22-Nov-2011 Available at: http://www.platts.com/RSSFeedDetailedNews/RSSFeed/ElectricPower/6704486

[22] Source: https://saveonenergy.ca/Business/Program-Overviews/Demand-Response/Demand-Response-3.aspx

Midwest ISO[23]

MISO provides a range of demand side resources that receive capacity verification. Some of which participate in both energy and capacity markets. Load Modifying Resources (LMRs) are resources that only have an obligation to respond. Their availability requirements are:

- Maintain target level for 4 continuous hours
- Able to respond at least 5 times per year

NYISO (New York)[24]

Installed Capacity Special Case Resources (SCR) — Capacity payments and energy market payments.

- SCR must commit to a load reduction of at least 100 kW with 100 kW increments, subject to a one-hour verification through actual events or NYISO initiated tests
- Minimum duration is 4 hours
- Dispatch notice is 2 hours but must be proceeded by a 21 hour ahead notification

NYISO Also runs an 'Emergency Demand Response Program' whereby payment for energy reduction only.

PJM[25]

PJM offer a suite of load management products with different availability. These are:

- Limited DR: Up to 10 interruptions, minimum 6 hours. June to Sept weekdays, Noon to 8pm
- Extended Summer DR: Unlimited interruptions, min10 hours duration, May to Oct, 10am to 10pm
- Annual DR: Unlimited interruptions, minimum duration 10 hours

Participation in the lower-availability products is limited and an auction process is used to allocate resources where there is excess supply. As a result the price of the products can vary.

For all products a maximum 2 hours notification period applies.

---

23 Sources: The Brattle Group, 'Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design', January 19, 2010, Elements, available at http://www.brattle.com/_documents/uploadlibrary/upload832.pdf

MISO Integration Training, Level 100 — Demand Response as a resource. Available from www.midwestiso.org.

24 Source: NYISO Installed Capacity Manual, January 2012

25 Sources: PJM training material available at http://www.pjm.com/training/training-material.aspx.

For Discussion

Prepared For:

RCM Working Group

RCM Review Report 2 for RCM Working Group

Prepared By:

The Lantau Group (HK) Limited

1902A Tower Two Lippo Centre

89 Queensway, Hong Kong

Date: 10 April 2012

TABLE OF CONTENTS

TABLE OF FIGURES

TABLE OF TABLES

1. OVERVIEW

At the March Reserve Capacity Mechanism Working Group (RCM WG) meeting, a number of issues were raised for further discussion. Ahead of turning to those issues, we summarise three key points from the previous meeting:

- The RCM is an administrative mechanism and, by design, does not adjust as dynamically to market conditions as a pure market-based mechanism would. While that may make the RCM less-than-perfect, it does not necessarily mean the RCM is "broken". The perfect can, as everyone knows, be the enemy of the good. If the RCM works well enough, or relevant RCM parameters are able to be adjusted frequently enough and with sufficient transparency, then the case for changing the RCM becomes weaker. The case for changing the RCM depends on whether the RCM adjusts sufficiently to stop (most) investment that is not needed while supporting (enough) investment that is needed. It also depends on the costs and risks associated with designing and implementing changes that achieve the desired results without costly unintended consequences.
- Currently, there are too many capacity credits in the WEM. Regardless of cause(s), which we consider below, the economic value of capacity credits currently available in the WEM is substantially lower than the RCP value set by the workings of the RCM. The RCP is too high when it creates a continuing "development" signal for capacity credit resources at a time when there is already a significant excess of reserve capacity.
- The results of the MRCP review should not be underestimated in terms of their impact on investment signals in the WEM. The significant reduction in the MRCP drives a flow-through reduction in the RCP, which naturally reduces the commercial attractiveness of potential sources of new capacity credits, all else equal.

In the follow-on discussion, we look at three issues in more detail:

- What has "caused" the excess capacity in the WEM, and how (whether) that matters in thinking about the role of the RCM and scope for changes to it;
- How the RCM and capacity "markets", generally, influence investment decisions by type of resource; and
- Evolution of the RCM, taking into account the MRCP review and other concerns identified.

2. CAUSATION

2.1. THE RCM AND OTHER DRIVERS

The amount of excess reserve capacity in the WEM arises from a number of sources. Table 1 estimates new capacity entering the WEM by attributed factor.

Table 1: Capacity additions (MW) by attributed factor[1]

	Capacity Year						
Attributed Factor	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**Total**
Schedule 7	536						536
Displacement tender		256					256
MRET		1	1	90	5	19	116
Government policies					220		220
Market outcomes		331	109	10	112		562
Demand-side resources	47	0	71	87	181	45	431
Total Capacity Addition	583	587	181	187	518	64	2120
Excess Reserve Capacity	278	527	113	302	495	775	

The attributed factors have included:

- Schedule 7 of the Electricity Corporations Act 1994 – which was the requirement by WPC to tender for new capacity through an open and non-discriminatory process should it require new energy or capacity in the SWIS. This was in force until WPC was disaggregated;
- The Displacement Mechanism in the Original Vesting Contracts (dated 2005), which applied to Synergy and commenced after WPC was disaggregated. Under this Mechanism, Synergy was required to Tender for certain volumes of energy and capacity (which could be supplied by new or existing plant) to meet franchise customer volumes;
- The Mandatory Renewable Energy Target – which requires that all retailers supply a certain percentage of their loads from renewable energy sources. This target was set at 9500 GWh across Australia in 2001 and increased in 2009 with an Expanded MRET intended to target 20 percent of electricity to be supplied by renewables by 2020. This has effectively driven a growth in renewable options with the penalty payments of AUD40/MWh from 2001 to 2010 and AUD65/MWh from 2010; and
- Certain policy decisions by the WA Government such as the refurbishment of Muja AB (220 MW).

Schedule 7 and the Displacement Tender accounted for over 780 MW, but affected the WEM from the beginning. Subsequent entry decisions would have been taken with knowledge of the effect or likely effect of those initial policy-driven initiatives. The combination of resources added to the WEM due to market outcomes (essentially, the absence of any other attributed factor) and demand-side resources contributes the vast

1 Source: IMO

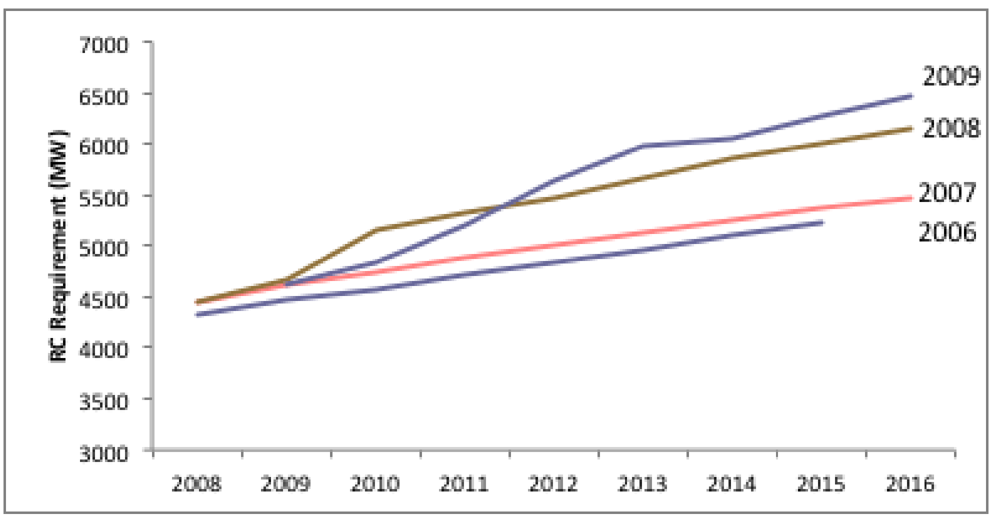
majority of capacity credit sources added to the WEM, accounting for over 960 MW. The MRET scheme accounts for significant renewable resource adoption, principally wind, particularly for the capacity year 2011. It is also clear that public policy also influences investment timing and magnitude, a factor that is important to consider when determining how much risk to expose market stakeholders to with respect to the prospect that excess reserve capacity can be caused by factors originating outside of the WEM.

Looking forward, the RCM is the only mechanism left in the SWIS (other than government direction through Verve) to drive new investment in non-intermittent facilities. Schedule 7 and the Displacement Mechanism no longer exist. The expanded MRET scheme will continue to bring new capacity online, though most of this is likely to be intermittent in nature. Given the lead times for baseload capacity, the RCM needs to guide investor expectations such that future investments are expected to be commercially viable at the same time they are also physically needed in the WEM.

2.2. LOAD FORECAST UNCERTAINTY

Load forecasts are inherently uncertain as market conditions can change dramatically over time. From 2006 to 2009, forecasts exhibited considerable timing uncertainty (compare 2008 and 2009), but were generally upward trending, with each subsequent year's outlook suggesting even greater reserve capacity requirement than had been expected previously, as shown in Figure 1.

Figure 1: Load forecasts: 2006 to 2009[2]



More recent forecasts indicate a different "trend". Figure 2 shows the extent of change by showing the most recent forecast 2011 (black) compared to 2010 (red) as well as earlier forecasts. The forecast for 2009 is shown for reference, as well. Notably, between 2009 and 2010, virtually no growth was projected.

2 Source: IMO

Figure 2: Load forecasts: 2009-2011[3]

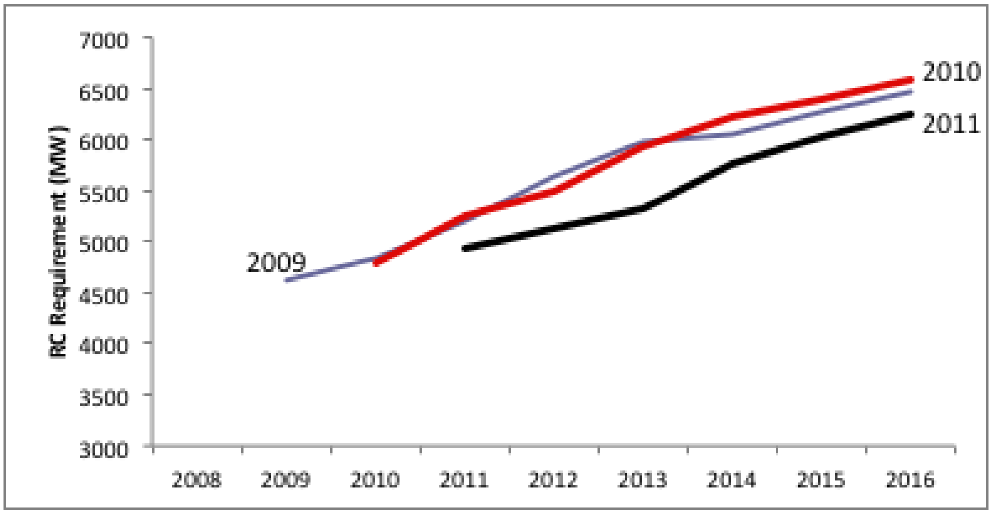


Table 2 summarises the RCR by capacity year over time.

Table 2: Reserve Capacity Requirement

	SOO Publication Year					
Capacity Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
2008	4322	4442	4452			
2009	4463	4609	4666	4623		
2010	4581	4737	5146	4836	4778	
2011	4721	4881	5314	5191	5261	4930
2012	4844	5009	5477	5632	5501	5121
2013	4965	5122	5674	5978	5937	5312
2014	5102	5257	5849	6049	6213	5773
2015	5219	5361	6004	6268	6392	6032
2016		5470	6148	6465	6597	6240

By 2011 the RCR for 2013 had been revised downward by 189 MW from what it had been in 2010 for the 2012 capacity year. The downward revision is particularly stark when considering that the projected estimated of the RCR for 2013 had been 5937 MW in 2010, a value that was revised down to 5312 MW, a downward revision of over 600 MW. Clearly, load uncertainty is a driver of the economic value (and risk) of capacity credits.

The challenge of forecasting lumpy loads in a smaller market is evident in Figure 3, which illustrates the range of uncertainty present in a single forecast.

3 Source: IMO

Figure 3: The challenge of block load forecasting in the WEM[4]

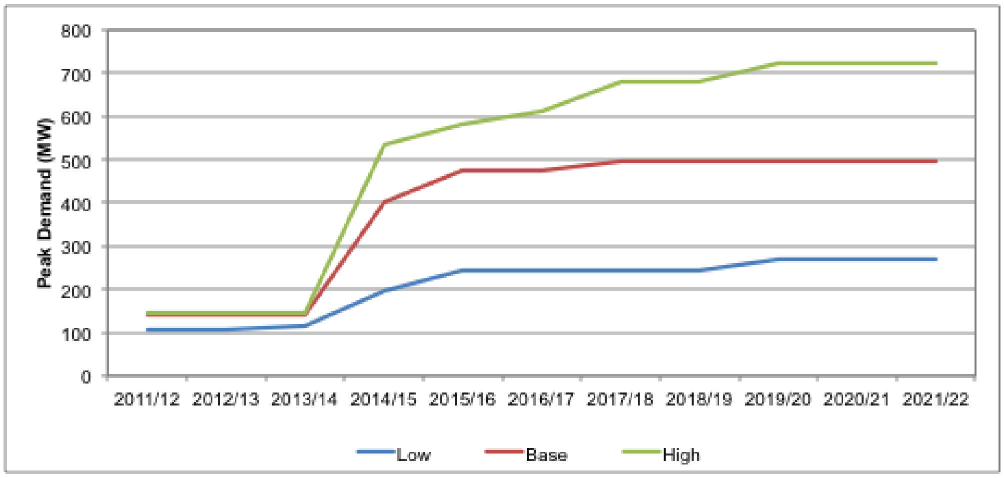
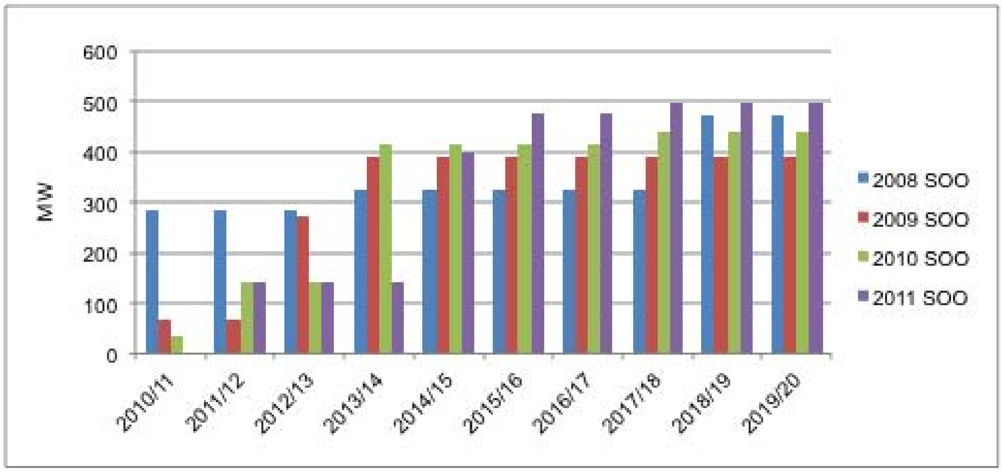


Figure 4 highlights the extent of uncertainty across SOO forecasts with respect to just six potential large loads. Whereas on one side of the equation it is important to establish the committed status of generation projects, it has proven difficult to achieve a similar level of “commitment” for block loads. In other markets, centrally developed forecasts and data are often an important service, but responsibility for interpreting forecasts and forming views of future supply and demand levels remains with the investor. A potentially important question for the RCM is whether or how load forecast uncertainty, which at some point is irreducible, is to be handled. Theoretically it may be possible to improve a forecast, but that is not the issue here. The issue, which does not go away even if a forecast is the very best possible forecast, is that the future is uncertain, and that, in the WEM, the RCR can be influenced significantly by changes in the timing of a very small number of large potential loads.

4 Source: IMO

Figure 4: Block load forecasting uncertainty across forecasts[5]



5 Source: IMO (From 2011 Statement of Opportunities)

3. HOW THE RCM INFLUENCES CAPACITY INVESTMENT CHOICES

A MW of capacity cannot just be summoned to exist in specific hours. Investment is required. In order to attract and support new investment, the expected value of the RCP must be capable of equalling or exceeding the annual carrying charge (capacity charge) associated with a pure peaking (or peak lopping) resource. The MRCP sets the maximum value for the RCP in the WEM. The MRCP needs to be high enough that the resulting *expected RCP* is able to support new capacity investment when and as that investment is actually required. The other condition is that the expected RCP should be *less than* the level necessary to support new capacity investment at a time when such capacity investment is not needed.

3.1. THE VALUE OF PURE CAPACITY

Consider the choice between investing in an incremental MW of a pure peaking resource or an incremental MW from a unit with a lower marginal dispatch cost. Both units would provide exactly the same reliability benefit. In addition, the unit with the lower dispatch cost could displace higher-cost resources. Accordingly, the unit with the lower dispatch cost has a second source of value.

The total value associated with a unit with a lower dispatch cost than a pure peaking unit resource equals the contribution from both sources—that is, the capacity value plus the additional dispatch value. Static equilibrium is a notional point where a power system has a perfectly optimal mix of all different types of capacity. At this point, the total value for either a baseload or a mid-merit technology would just equal the annual carrying cost for the peaking resource (assuming that the peaking resource is an economic addition at the margin). In short, the higher carrying cost of a non-peaking resource is perfectly offset by the dispatch cost savings. This point of optimality gives rise to the following simple "rule":

$$Capacity\_value + Annual\_dispatch\_cost\_savings = Annual\_carrying\_cost$$

If a power system has the optimal mix of technology to serve expected load, then as load grows, new investment will be needed in each load segment whether it be new peaking capacity, new mid-merit (flexible) capacity or new baseload capacity. When the plant mix is optimal, each type of capacity in the optimal mix would fulfil this equilibrium condition.

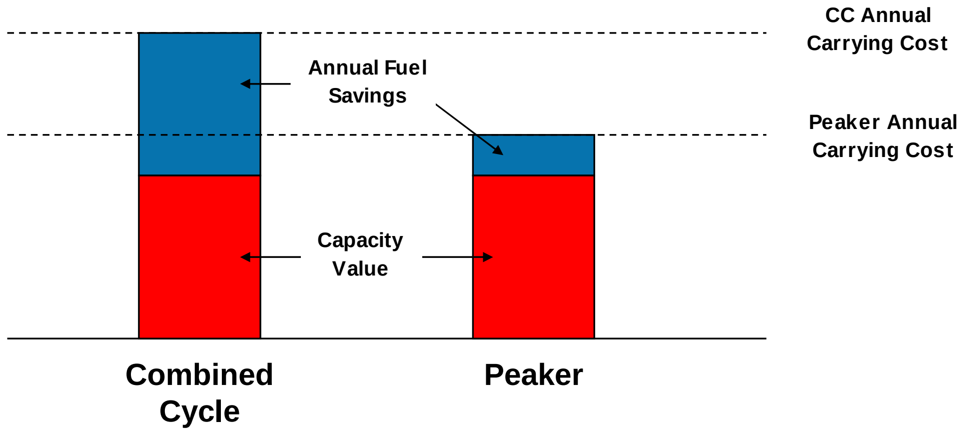


Figure 5: Optimal Investment by Type

It is the role of the RCM to produce the "red" portion of Figure 5, which in the WEM corresponds to the reference peaking technology (160 MW open cycle gas turbine). The energy market portion of the WEM then adjudicates whether dispatch cost differentials across different technologies and fuels provide sufficient additional value to tilt the investment decision away from a pure capacity resource and towards something else.

The workings of the RCM need to get the "capacity value" sufficiently right that the WEM neither falls short of capacity nor supports materially excess investment.

3.2. The MRCP review in perspective

The changes to the MRCP in the recently concluded review have resulted in an MRCP that reflects an expected value of new capacity—a best estimate of the cost of building a reference peaking resource. The result has been a significant reduction in the MRCP that, as previously discussed, reflects methodological and definitional considerations and not just revisions to parameters to reflect ever-changing market conditions. The review resulted in an overall reduction of approximately 32 percent in the MRCP for the 2014/15 Capacity Year. Of the overall 32 percent reduction, 23 percentage points reflect changes to the MRCP formulation, as summarised in Table 3.

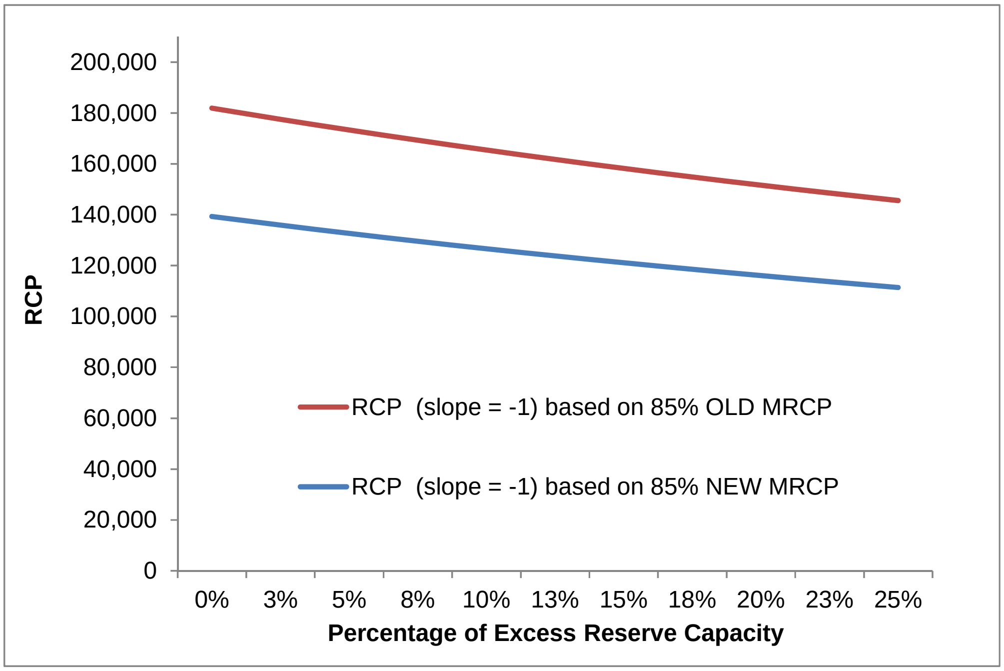
Table 3: Summary of MRCP review adjustments[6]

MRCP after year-on-year changes			$214,100
Methodological and Definitional changes	Amount $	Amount %	Adjusted Result
Inclusion of inlet cooling	-18,800	-8.80%	195,300
Revised Transmission Cost methodology	-30,300	-14.20%	165,000
Increased fuel allowance (increase from 12 to 14 hours)	100	0.00%	165,100
Use of average land cost	1,400	0.70%	166,500
Revised cost escalation/WACC methodology	-6,500	-3.00%	160,000
Debt issuance cost included in WACC (relevant portion)	-500	-0.20%	159,500
Annual insurance costs included in Fixed O&M	4,400	2.10%	163,900
Net change	**-50,100**	**-23.40%**	**$163,900**

6 Source: *Final Report: Maximum Reserve Capacity Price for the 2014/15 Capacity Year*, IMO, February 2012.

Figure 6 highlights the impact of the recent MRCP review on the relationship between the RCP and the amount of excess reserve capacity.

Figure 6; Impact of the MRCP review on the RCP relationship to excess reserve capacity



In the next section, we discuss the implications of this change and other potential changes that could be made to the RCM to improve its overall responsiveness to market conditions in the WEM.

4. OPTIONS AND APPROACHES: FURTHER DISCUSSION

4.1. OVERVIEW

The adjustment of the RCP plays two important roles:

- It establishes the risk borne by generators and retailers respectively in relation to the overall level of excess reserve capacity in the WEM. If the RCP adjusts effortlessly and perfectly with market conditions, the risk of excess is borne primarily by capacity resource investors. If the RCP adjusts less perfectly or in a constrained manner, more of the risk is shared by capacity resource users. In addition, if the adjustment is not "perfect" there is greater risk of inefficient outcomes (too much or too little investment). At the same time, pushing more risk to resource investors tends to create more volatility by increasing the sensitivity of investment viability to market conditions.
- It determines the overall economic value created or destroyed by the workings of the RCM insofar as the RCM creates or supports appropriate signals for investment given supply and demand conditions and expectations in each Capacity Year.

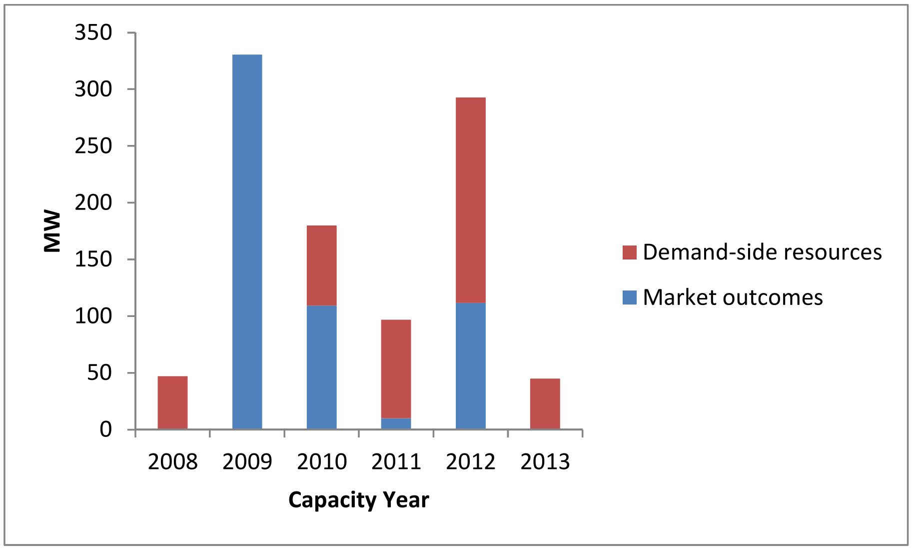
In this section we set out in more detail an approach based on modifying the existing RCP formula. This approach, though not purely market-based, involves changes intended to improve alignment with market conditions.

4.2. EVIDENCE THAT THE EXPECTED RCP IS BELOW THE COST OF NEW ENTRY

The significant reduction in the value of a Capacity Credit improves the alignment between the RCM value of a Capacity Credit and what a market-based mechanism would yield. In part due to the impact of the MRCP reduction and probably also due to the uncertainty created for investors as a result of simultaneous reviews of the MRCP and RCM, market-based investment in the WEM has fallen to essentially zero, a situation consistent with fundamental supply and demand conditions.

Figure 7 compares market-based investment and demand resource investment over time, highlighting the fall-off for the 2013 Capacity Year. Additional potential changes to the performance requirements of demand resources (to improve the consistency of treatment between demand resources and supply resources) resulting from the RCM review would likely reduce the overall level of capacity attributable to demand resources as well as reduce the amount of untapped demand resource remaining in the WEM.

Figure 7: Capacity Credit generating resources most strongly influenced by the RCM



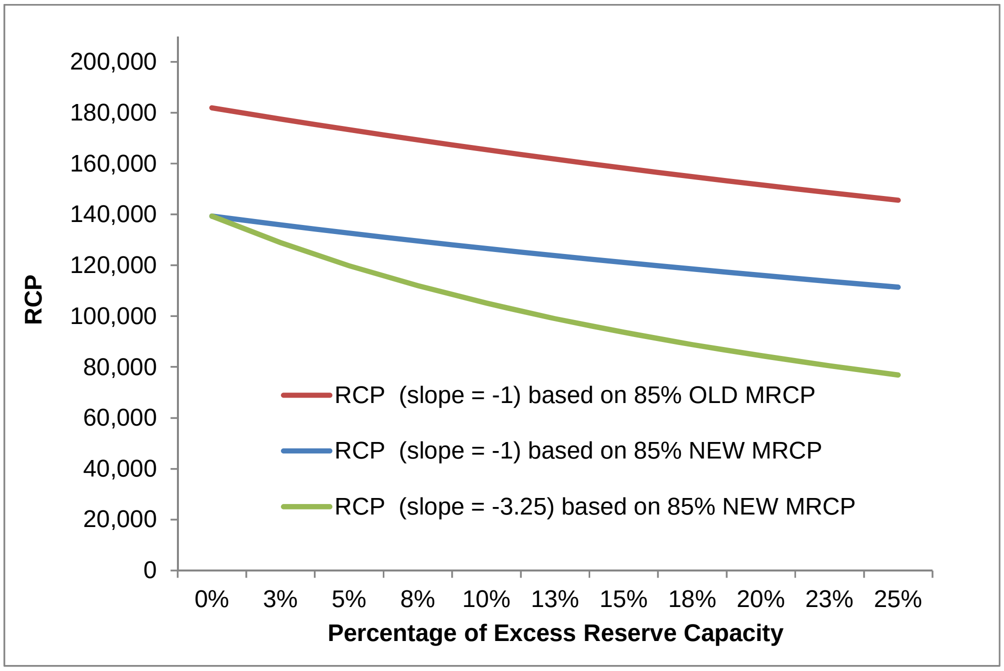
The absence of a clear "build signal" at this time in the WEM is a good thing because it aligns with a fundamentals-based analysis of what "should" be happening in the WEM at this time. However, it would be unwise to assume merely from appearances that all is now fine for the longer-term. At least two important aspects of the RCM pose on-going concerns:

- The RCM is no more sensitive to market conditions than before – the RCP has merely been re-floated downward as a result of the MRCP review; and
- The MRCP value itself, having been reduced, may no longer provide sufficient headroom for the "expected" long-term RCP to support investment.

4.3. The RCP formulation and the option of a steeper "slope"

Currently, the slope is "minus 1". The RCP applicable to uncontracted capacity credits is adjusted downward in proportion to the amount of excess reserve capacity. A slope factor of "minus 3.25" (a specific value discussed later) would reduce the value of an uncontracted capacity credit at faster rate, strengthening the signal to generation investors to defer capacity investment until demand has increased, as shown in Figure 8.

Figure 8: RCP Adjustment Formula Comparison



The steeper slope would be implemented within the existing RCM structure and, of course, would be amenable to periodic review for the purposes of tuning the RCM to improve efficiency over time. Substantial justification for a steeper slope exists, based on the fact that a market-based valuation of excess reserve capacity would yield values significantly less than what the RCM currently yields, as set out in the Appendix of the TLG report for the March Working Group meeting.

A steeper slope, in combination with the MRCP revision, would significantly alter the value of a Capacity Credit compared to previous Capacity Years. For example, a 15 percent excess reserve capacity would result in the RCP being 57.1 percent of the MRCP given a slope factor of “minus 3.25”, rather than 73.9 percent under the current adjustment formula, as summarised in Table 4.

Table 4: RCP as a Percentage of the MRCP (starting at 85% of MRCP)

Amount of Excess Reserve Capacity	Based on "-1 slope"	Based on "-3.25 slope"
0.0%	85.0%	85.0%
2.5%	82.9%	78.6%
5.0%	81.0%	73.1%
7.5%	79.1%	68.3%
10.0%	77.3%	64.2%
12.5%	75.6%	60.4%
15.0%	73.9%	57.1%
17.5%	72.3%	54.2%
20.0%	70.8%	51.5%
22.5%	69.4%	49.1%
25.0%	68.0%	46.9%

4.3.1. The relationship between the RCP and the MRCP

Currently, the RCP for uncontracted capacity credits begins at 85% of the MRCP. Given that the newly revised MRCP is presumed equal to the reasonable cost of capacity, the current formula for setting the RCP (beginning at 85% of the MRCP and going downward, potentially, from there) cannot cover that cost even if the amount of excess reserve capacity reduces substantially.

It would make more sense for the RCP to be directly linked to the MRCP, rather than continue with the definition of the base RCP as being 85 percent of the MRCP, an adjustment that has unclear origins and no obvious foundational logical support. Eliminating the initial "85 percent adjustment step" would reduce the penalty relative to the MRCP for very small amounts of excess reserve capacity, but a steeper slope would offset this impact, by increasing risk, as shown in Figure 9 and Table 5.

Figure 9: RCP with adjusted starting point and slope

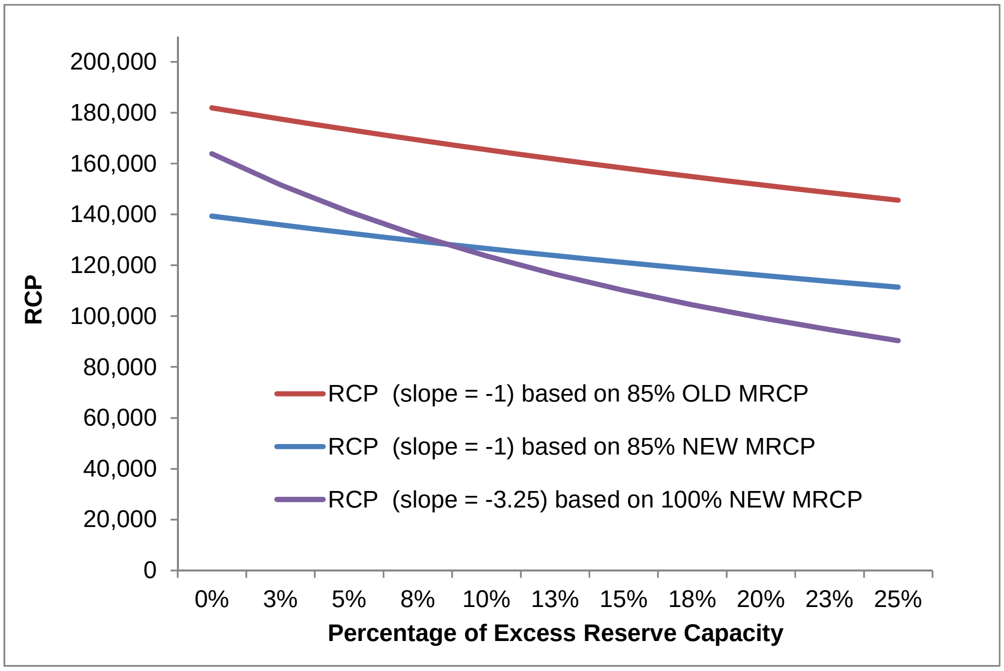


Table 5: RCP as a Percentage of the MRCP (Alternative starting point)

Amount of Excess Reserve Capacity	Based on "-1 slope" starting at 85 percent of the MRCP	Based on "-3.25 slope" starting at 100 percent of the MRCP
0.0%	85.0%	100.0%
2.5%	82.9%	92.5%
5.0%	81.0%	86.0%
7.5%	79.1%	80.4%
10.0%	77.3%	75.5%
12.5%	75.6%	71.1%
15.0%	73.9%	67.2%
17.5%	72.3%	63.7%
20.0%	70.8%	60.6%
22.5%	69.4%	57.8%
25.0%	68.0%	55.2%

The steeper slope and adjusted starting point are attractive in their simplicity and their ability to penalise investment progressively as the amount of excess reserve capacity increases—more in line with what a market-based mechanism would achieve.

4.3.2. Picking values

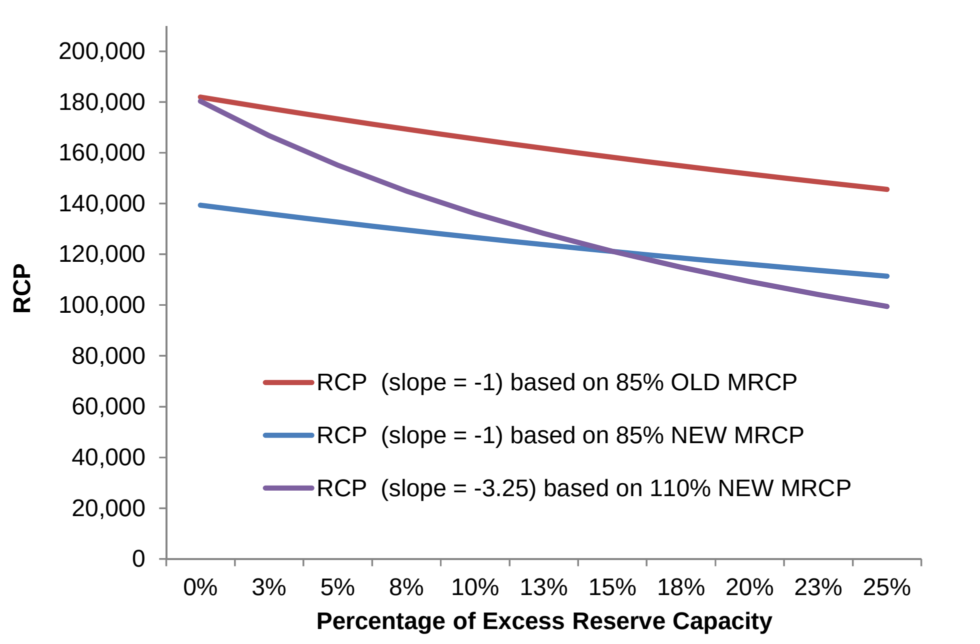
The steeper slope and adjusted starting point result in values for the RCP that are below the revised MRCP and the previous MRCP in all instances. While not a formal reference point, the previous MRCP has the useful quality that it clearly supported investment. The MRCP itself is *supposed* to be able to support investment, but it has not been established that values at varying levels *below* the MRCP will be able to support the amount or type of investment desired in the future. Indeed, the values used to establish the MRCP were drawn from actual costs and technology design choices making it less likely that RCP values *below the MRCP* can support investment in the reference peaking technology to the degree the WEM requires for long-term timely investment support.

The MRCP plays two roles in the RCM. Firstly, it is the maximum value that can be used in an auction when tendering for new capacity. In such instances, the MRCP can be locked-in for ten years. Secondly, the MRCP is the value that sets the maximum for the RCP, an inherently short-term (annual) value. If the annual RCP can fall below the MRCP, but can never rise above it, the *expected* RCP must be less than the MRCP. If the MRCP has been properly estimated, then this RCP<MRCP relationship could pose a serious obstacle for investors in the future.

Consequently, in addition to a steeper slope to make the RCP more market-sensitive, we propose that the RCP be allowed to increase above the MRCP as the amount of excess reserve capacity approaches zero. On the assumption that the WEM will experience, due to its lumpy nature, periodic excess reserve capacity between 0 and 10% under normal conditions, a maximum RCP value of 110% of the MRCP is suggested, as shown in Figure 10.

This 110% value has the additional feature that, when combined with a steeper slope of “minus 3.25” results in a near-term impact on the RCP that is very close to what has occurred already due to the MRCP review. Whether this feature is a net plus or a minus will depend on stakeholder perspectives, but, at minimum, it mitigates the need for a transition mechanism. The other feature of this combination of adjustments is that at zero excess reserve capacity the RCP would be almost the same as the value obtained under the “old” MRCP methodology. Again, while the old value is not a formal reference value (and need not be), it is a data point that is known to have supported vigorous investment interest—the key desirable feature of a true “maximum” annual RCP value.

Figure 10: Adjusted RCP formula starting at 1.1x the new MRCP



4.3.3. Other Related Issues

The RCM developed the way it has developed in part due to the inability to be certain that a retail load will actually exist. Declaring an intention to bilaterally contract provides an "off-ramp" situation in case the bilateral contract was not forthcoming. The IMO currently provides a put option in the form of the RCP payable for a Capacity Credit to the generation investor. The value of that put option, when it is too high, can support excess investment, but it may also support bilateral transactions between smaller parties by mitigating counterparty concerns.

4.4. SUMMARY

The RCM avoids some known complexities and risks of pure auction- or trading-based approaches in relation to the definition of the product being traded, the volatility associated with market-based pricing and counterparty risks. The size of the WEM and the lumpiness of the market would likely be a challenge for a more short-term defined auction product. At the same time, the current RCM parameters can be adjusted to better tailor the investment and value signals to ever-and-often-rapidly changing conditions in the WEM.