Independent Market Operator

Reserve Capacity Mechanism Working Group (RCMWG)

Agenda

Meeting No.	4
Location:	IMO Board Room, Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Tuesday 29 May 2012
Time:	Commencing at 2.00 to 5.00pm

Item	Subject	Responsible	Time
1.	**WELCOME**	**Chair**	2 min
2.	**APOLOGIES / ATTENDANCE**	**IMO**	2 min
3.	**MINUTES FROM MEETING 3**	**IMO**	10 min
4.	**ACTIONS ARISING**	**IMO**	10 min
	(a) FEEDBACK FROM MEMBERS ON WORKSTREAMS 1 & 2		
	(b) ASPECTS OF DIFFERENT CAPACITY MARKETS		
	(c) MARKET EFFECTIVENESS REPORT RECOMMENDATIONS		
5.	**HARMONISATION OF DEMAND SIDE AND SUPPLY SIDE CAPACITY RESOURCES (WORK STREAM 2)** *Presentation by Dr Richard Tooth*	**Sapere Research Group**	90 min
6.	**RCM REVIEW REPORT 2 (WORK STREAM 1)** *Presentation by Mr Mike Thomas*	**The Lantau Group**	30 min
7.	**DYNAMIC RESERVE CAPACITY REFUND REGIME** *Presentation by the IMO*	**IMO**	
8.	**GENERAL BUSINESS**	**Chair**	10 min

Independent Market Operator

Reserve Capacity Mechanism Working Group

Minutes

Meeting No.	3
Location:	IMO Boardroom Level 3, 197 St Georges Terrace, Perth
Date:	Tuesday 17 April 2012
Time:	Commencing at 2.00pm – 5.30pm

Attendees	
Allan Dawson	Chair
Suzanne Frame	IMO
Neil Hay	System Management (Proxy)
Andrew Sutherland	Market Generator
Brad Huppatz	Market Generator (Verve Energy)
Corey Dykstra	Market Customer
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	
Richard Tooth	Presenter (Sapere Research Group)
Mike Thomas	Presenter (The Lantau Group)
Aditi Varma	Minutes
Fiona Edmonds	Observer
Jenny Laidlaw	Observer
Greg Ruthven	Observer
Aaron Breidenbaugh	Observer (EnerNOC, USA)
Ken Schisler	Observer (EnerNOC, USA)
Paul Troughton	Observer (EnerNOC)

Apologies	
Ben Tan	Market Generator
Shane Cremin	Market Generator
Brendan Clarke	System Management

Item	Subject	Action
1.	**WELCOME AND APOLOGIES / ATTENDANCE** The Chair opened the third 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 Brendan Clarke, Mr Ben Tan and Mr Shane Cremin prior to the meeting. The Chair acknowledged Mr Neil Hay as proxy for Mr Clarke. The Chair also introduced Dr Richard Tooth from Sapere Research Group. The Chair also noted observers from EnerNOC, USA in attendance.	
2.	**MINUTES ARISING FROM MEETING 2** The minutes were accepted as a true and accurate record of the meeting.	
3.	**ACTIONS ARISING** The Chair noted that all action points from the previous meeting had been completed.	
4.	**PRESENTATION: Harmonisation of Demand Side and Supply Side Resources by Dr Richard Tooth, Sapere Research Group** The Chair invited Dr Richard Tooth to present his paper. The following points of discussion were noted: • On the issue of Availability Classes for Demand Side Management (DSM), Mr Jeff Renaud observed that the refund regime for DSM becomes more lenient in higher Availability Classes. However, it is more difficult to recruit customers in higher Availability Classes because of the associated opportunity costs of being available for greater number of hours. He also noted that Demand Side Aggregators (DSA) would generally absorb refunds for non-performance and would not pass those costs on to their customers as it creates disincentives for signing up to a demand management program. With regard to Dr Tooth’s comment that there was potential for some DSM programmes to offer more availability, he observed that there was a range of loads with some being indifferent to providing greater availability and others being opposed because of the costs of potential production shut-downs. He added that a DSA, however, with a portfolio of customer loads would be in a position to mitigate that risk for individual market customers. • Discussion ensued on the order of dispatch of generators and DSM. Some members argued that the value provided by generators and DSM may be different because key variables such as response time to dispatch instructions from System Management for the two was different. • Discussion ensued on when DSM can be dispatched. Mr Neil	

Item	Subject	Action
	Hay noted that under the current Availability Classes, System Management would not dispatch DSM if it believes that the peak of summer has not yet been reached. Mr Dykstra observed that this would imply DSM is considered to be the last resort. Mr MacLean queried if this implied that System Management would have different operational guidelines in early summer vis-a-vis late summer. Mr Hay disagreed with this and noted that consideration would be given to System Management's expectation that the peak summer day is yet to occur. • Mr Huppatz observed that this might indicate that DSM could be considered to be more valuable during peak summer (for example, from January to March) than during other months. Mr Geoff Down observed that some level of uncertainty needs to be factored in dispatch decisions. • Mr Renaud noted that in most markets DSM is used in emergency reliability conditions. He observed that in this case it seemed that the issue was not the dispatch of DSM itself but System Management's confidence level in dispatching DSM when faced with peaky circumstances early in summer. Mr Hay agreed with the statement and noted that if System Management was faced with the option of shedding load versus dispatching DSM, it would always dispatch DSM but it must give adequate consideration to the fact that that option would then be used up and would not be available if a similar circumstance occurred again. Mr Payne noted that the capacity provided by DSM in the market currently might be sufficient to provide some flexibility of dispatch for System Management. However, Mr Dykstra and Mr Stevens argued that dispatch decisions were constrained because of DSM availability limitations. Mr Renaud mentioned that DSM could strive to provide advanced technological tools to System Management for better dispatch decisions. However the issue was more around the prescriptive grid conditions needed to dispatch DSM rather than the actual hours of availability of it. • Mr Breidenbaugh observed that in the US, the issue was not so much the availability duration of DSM but how often and for how long it was dispatched. He added that an important concern for DSM providers was performance measurement over their availability duration as that happened during the peakiest periods. He also observed that in the PJM market, DSM is only dispatched during reserve deficiency situation. • Discussion continued on how DSM participates in the energy market. Members discussed that there is an extra monetary benefit that DSM is able to receive because of savings resulting from lower consumption for the load and the dispatch payment for the DSA. The Chair noted that this was one of the issues being considered in the discussion on harmonisation. • On the issue of fuel availability requirements, members discussed the capacity refund regimes for peaking facilities and DSM facilities. Mr Sutherland noted that a peaking generator would have to bear fixed expenses in the event of capacity refunds whereas a DSA could contractually control this expense by not paying the load that did not perform. Mr Peake noted that there was no economic justification as to why DSM could not be	

Item	Subject	Action
	dispatched before a peaking generator if its marginal cost was lower. Mr Renaud noted the mechanism is based on value not cost to which Mr Peake responded that the value of the capacity provided by DSM changes throughout the Capacity Cycle. The Chair noted that this was an issue that is being considered in the discussion on harmonisation. He challenged the group to consider the inclusion of DSM in the balancing market as a potential solution for harmonisation of demand and supply side resources. Mr Breidenbaugh noted that it was important to note that DSM providers lose money if they are dispatched whereas peaking generators make money when they are dispatched. This implied that DSM providers would prefer not to be dispatched at times when the system operator wants them to. • The Chair noted that Dr Tooth had provided a spectrum of options which now need to be mapped on a continuum of pros and cons. He added that the group should consider that these solutions would affect many potential customers in Western Australia who are willing and able to provide curtailment. • Discussion ensued on potential solutions for harmonisation of demand side and supply side. Mr Breidenbaugh noted that changing availability requirements would require that DSAs review their portfolio of customers. However, changing other variables such as minimum hours of duration etc. would create unmanageable risks for DSA's because these variables affect all customers in the same way and little room for adaptability across portfolio is left for the DSA. Mr Renaud cautioned against over-specifying DSM requirements as that would severely limit the entry of DSM into the market. • The discussion concluded with the members agreeing that more work should be conducted on the potential solutions. The Chair noted that the solutions should be debated keeping in mind the right signals need to be provided at the right time. The Chair noted that some of these issues were also being assessed in PJM market. He encouraged members to send their feedback on potential solutions to the IMO. Members requested that information be provided on aspects of different capacity markets and on the dispatch of DSM since market start. Members also requested that the cost-effectiveness of different solutions should be presented. *Action Points:* • *RCMWG Members to provide feedback to the IMO on the proposed solutions for harmonisation of demand and supply side sources* • *The IMO to include information on the cost effectiveness of proposed solutions or harmonisation* • *The IMO to provide information to members on aspects of different capacity markets*	
5	**PRESENTATION: RCM Review Report-2 by Mr Mike Thomas, The Lantau Group** The Chair invited Mr Thomas to present his paper. The following points of discussion were noted:	

Item	Subject	Action
	• On the issue of forecasting uncertainty, Mr Sutherland noted that forecasting error made a significant contribution to over-supply of capacity. Mr MacLean observed that because forecasts inherently have a level of uncertainty, the question to ponder is what protections exist in the market for existing loads to be shielded from the costs of committed loads not becoming available. • There was some discussion on the level of DSM contracted bilaterally in the market. Mr Breidenbaugh noted that if the intent was to encourage bilateral contracting, then DSM might be driven out of the market. Mr Thomas noted that the intent of the proposed solution was not to drive out any particular technology from the market. • <u>On the table detailing factors to which capacity additions could be attributed, Mr Dykstra queried if data could be provided on capacity credits by facility. Further,</u> Mr Dykstra noted that the objective was to make sure that at any time, the right price signal was available to anyone contemplating making capacity available to the market. He noted that the reserve capacity price should be set at the marginal value of a unit of capacity irrespective of the marginal cost associated with that unit of capacity. He added that the price-based solution may not be productive as it is an administrative tool and it might be more useful to consider a spigot control mechanism. Discussion ensued among members on the advantages and disadvantages of a spigot control mechanism vis-a-vis a price-based mechanism. Mr Breidenbaugh observed that most capacity markets have some form of administrative determination of variables such as downward sloping demand curve that ultimately determine the price. He observed that the cost of new entry should be well below the capacity price to encourage new technology. At the same time, it should reduce enough at appropriate times to signal the exit of inefficient technologies. • Discussion ensued among members on bilateral contracting in the market. The Chair noted that the market was quite concentrated on the retailer side. Mr Huppatz observed the reduction in reserve capacity price if a number of uncontracted capacity credits existed in the market. There was some discussion among members on whether the sliding scale of price determination should be reviewed annually. The Chair noted that there is always a lag time between cause and effect in the capacity mechanism. • The Chair concluded the discussion by noting that there may be some merit in the proposal. He observed that there is a balancing act between price incentive and the level of capacity resources. He encouraged members to provide feedback to the IMO on the proposed solution so that it could be developed further. *Action Points:* • *RCMWG Members to provide feedback to the IMO on the proposed sliding scale determination of Reserve Capacity Price.*	
6	**CLOSED** The Chair thanked all members for attending the meeting and added that the next meeting is tentative based on the development of the two work streams. He also noted that the next work stream on dynamic	

Item	Subject	Action
	refund regime would be kick-started in the next meeting. He declared the meeting closed at 5.30 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	RCMWG Members to provide feedback to the IMO on the proposed solutions for harmonisation of demand and supply side sources and proposed sliding scale determination of the Reserve Capacity price	IMO	April	Completed- See attached
2	The IMO to include information on the cost effectiveness of proposed solutions or harmonisation	IMO	April	In progress
3	The IMO to provide information to members on aspects of different capacity markets	IMO	April	Completed- See attached

From: Andrew Sutherland
Sent: Tuesday, 8 May 2012 10:24 AM
To: Market Admin
Subject: FW: Deadline extended for feedback: proposed solutions for oversupply of capacity and harmonisation of demand and supply side sources
Importance: High

Courtney, apologies for this late response. Crazy week last week.

A couple of points to raise which for the most part I think I have already raised in the working group meetings but would prefer specifically addressed in the papers if not already done so:

Harmonisation:
The proposal of harmonising the service level requirements of demand response (DR) and supply side solutions appears to have been taken up without considering other options. I would like the design team to consider whether the following are appropriate alternatives:

1. **Low Fixed, High Variable Payment Structure**
   DR has a high marginal cost but very little fixed costs, the direct opposite of the capacity market mechanism. It does not provide an incentive for the delivery of DR when needed. High availability payments and low dispatch payments promote inclusion from participants to see if they can be paid without ever actually delivering.
   The payment to DSM of a capacity credit based on the cost of 160MW OCGT will provide continued incentives for DSM which will only diminish to the extent that all of these demand side resources are exhausted <u>and</u> the DSM Aggregator has reached a limit of their commercial risk.
2. **Define a DSM Aggregator's Contract vs Capacity ratio:**
   Harmonising demand and supply side solutions may not place DSM on an equal footing with generation as a DSM Aggregator may take commercial risk on the availability it can actually provide. Alternatively it could pass through this risk to demand side suppliers who simply return the capacity payments. As an alternative to harmonising the service level, has the design team considered defining an Aggregator i.e. a reserve or oversubscription ratio between DR capacity credits and contract capacity? This is a subtle difference to harmonising.

Capacity Price Response to Excess:
The steeper slope and greater responsiveness of the capacity price to excess capacity appears appropriate, however, could make investment in the WEM problematic as there is currently little commercial incentive for Market Customers (MCs) to contract bilaterally. This commercial incentive could be achieved by increasing the capacity price for normal levels of capacity supply and in so doing place the risk on MCs that they could pay significantly higher than the fixed costs of a 160MW OCGT. If there is no incentive for MCs to bilaterally contract then the proposed steeper fall off of capacity prices will make merchant investment in the WEM very difficult to achieve for anything other than DSM.

Fuel Requirements:
The current application of 14hr fuel requirements is inefficiently high and effectively mandates that facilities install dual fuel burners or be a part of a gas portfolio or install gas storage. The original market rules clearly considered it adequate for certification to be on the basis of the IMO's reasonable expectations of available capacity during peak demand times. The capacity refund mechanism already places a high incentive on participants to manage their commercial risk regarding fuel availability.

Adding a 14hr fuel requirement places another layer of unnecessary regulation. The preferred proposal put forward by the design team is to allow commercial incentives to drive Market Generator behaviour to manage their fuel requirements with the IMO retaining their ability to use reasonable expectations in certifying capacity.

Regards
Andrew

From: Patrick Peake
Sent: Friday, 4 May 2012 1:33 PM
To: Allan Dawson; Market Admin
Cc: Courtney Roberts
Subject: Reserve Capacity Mechanism Working Group

Hi Allan

I am following up on your invitation to provide responses to the presentations by Richard Tooth at the last RCMWG and the two presentations we have had from Mike Thomas. Can I first say that the input from these two consultants to be very helpful – they are certainly bringing new thoughts to the table which can only assist in developing improvements to the RCM. I also spoke with Richard on the phone this week and we discussed a number of matters.

Attached are comments on the proposals from Mike Thomas of Lantau and on harmonization of DSM and Generation. Attached also are some comments in respect to dynamic reserve refunds for next month's discussions. Should you wish, these comments may be forwarded to all members of the Working Group and your consultants.

Lantau proposals for Reserve Capacity Mechanism

Mike Thomas made several key points in respect to the RCP and oversupply:

- Whilst there is currently a surplus of generation, it needs to be remembered that there were shortages when the market commenced and that changes to forecasts have been a key factor in the current excess;

- There appears to be no reason behind setting the Reserve Capacity Price (RCP) at 85% of the Maximum Reserve Capacity Price (MRCP). No-one appears to know why this was introduced and no cogent reasons have been presented for this reduction.

- The MRCP is a ***maximum*** figure but it is determined by preparing the ***best estimate*** of the cost of new generation plant. By using the MRCP as a maximum, it can never accommodate the possibility that actual plant costs may vary above the best estimate.

- The mechanism by which the RCP reduces in direct proportion to oversupply does not send a very strong signal to developers to ease back in bringing new capacity into the market.

- While a RCP of $186,000 per MW per year appears to be encouraging too much capacity into the market, there is no clear indication as to whether prices based on the new MRCP calculation process will be sufficient to bring adequate capacity on stream.

Mike is now recommending that:

- The 85% factor be removed:

- The RCP be set equal to 110% of the MRCP when the supply quantity exactly equals the requirement; and

- The reduction in price due to excess capacity is much stronger.

Perth Energy generally supports these proposals though we consider that a floor price, say 75% of the MRCP, is essential to protect investors and hence reduce risk and financing costs.

Harmonizing DSM and Generation

The point has been made strongly that DSM and generators provide the same service, namely a MW of capacity, and that this justifies their receiving the same capacity credit income. At the time of certification, two years ahead of time, this is true but on the actual day when demand occurs the service differs significantly:

- DSM is allowed to ask for up to four hours notice;
- DSM is only required to run for four hours per event;
- DSM may offer a maximum of 24 hours annual operation;
- DSM is effectively only used in mid to late summer; and
- DSM does not have to dispatch at its marginal cost where this is less than the alternative maximum STEM price.

As a consequence, on a day of high demand, DSM is not offering the same service as a generator which is required to be instantly available at all times.

The differences in service delivered on the day have a profound impact on the costs of providing the service. For a generator to be instantly available on a 24-7 basis it must incur significant costs associated with:

- 24-7 monitoring of the plant;
- 24-7 staff response capability;
- Regular test running to ensure that the plant is available to start and run; and
- Potential for significant refunds.

The task of providing peak capacity from a generator is one of the most demanding in the WEM. The plant must be kept in a constant state of readiness to start and run but its production cost means that it is virtually never cleared in the STEM. Its operation is limited to test runs which must be minimized to avoid incurring unnecessary fuel costs. All of the auxiliary systems are on stand-by for most of the year but must respond perfectly when called if refunds are to be avoided.

The same is true to some extend for DSM providers but there are two very significant differences:

- A generator supplies reserve capacity as its prime line of business and if it fails to do this economically it goes out of business whereas for a business offering DSM its income is a bonus; and

- A DSM provider can have surplus individual providers so that a failure of some of these to deliver does not force it into a refund situation whereas the reserve capacity price does not allow a generator to internally hold spare capacity.

Perth Energy considers that if DSM and generators are to receive the same reserve capacity payment then they should be required to offer the exact same service. If the market considers there is value in generators being able to respond to a dispatch instruction without notice, at any time of day or night, during any season of the year and for an unlimited duration then these response capabilities should be recompensed – particularly as they cost a lot to provide.

One very useful piece of information for this discussion would be what amount of DSM comes from what types of provider. For example:

- How much comes from stand-by diesels whose dispatch cost is probably less than a diesel fuelled gas turbine?;
- How much comes from load cycling that can be implemented instantaneously?; and
- How much comes from other quick start activities that do not interfere with the provider's main business?.

This would give an estimate of what impact tightening up the obligations may actually have.

Dynamic Reserve Capacity Refunds

Reserve capacity refunds are intended to encourage generators to ensure that their plant is kept available to meet system demand. The refunds are sculpted to reflect the general expectation of when the power system is likely to be under greater stress. So the refunds in February and March are substantially higher than at other times.

In essence, the refunds are designed to drive the behavior of peaking plants – base load and mid-merit plants have the very high incentive of wanting to produce and sell electricity. Refunds are of much lesser significance to these types of plant.

One anomaly that has arisen is that plants sometimes incur refunds on occasions when there is a substantial excess of capacity on the grid. There are occasions when there is virtually no likelihood of a peaking generator being required to run, even on a peak season business day, but the plant still incurs refunds at a very high rate. This is seen to increase the cost of producing electricity but with no real benefit hence the idea of some form of dynamic refund.

Perth Energy considers that a dynamic refund is a sound move. This should be a discount from the refunds in the Table included within Market Rules clause 4.26. There should be no discount if the margin above the reserve capacity requirement is less than a defined value – say 10% - but if the margin exceeds this then the refunds should drop sharply in line with the sharp drop in the reserve capacity costs. This is because the additional reserve capacity has little marginal value.

It has been suggested that the reduction in refunds should be matched by an increase when the system is very tight. Perth Energy disagrees with this on the basis that the refund levels set in the Rules are based on the 1 in 10 year requirements. In other words, if we have 1 in 10 year conditions the refund levels give the incentives that the market intends.

It would also be appropriate to reconsider the absolute level of refunds. The refunds that can be incurred by a relatively short outage in summer are very high when compared to the expected return that the generator can make. The cost of refunds is not included in the calculation of the maximum reserve capacity price so any refunds have to come directly from revenue.

For a generator that is relatively new, and so has high capital repayments to make, a relatively small outage can cause serious financial difficulties. The working group should consider whether a lower level of refunds, which is still high enough to incentivize behavior, would be better for the market than risking driving a generator out of business and hence out of service. An assessment could be made of the level of refunds required to encourage a peaking plant to undertake good preventative maintenance and to respond promptly to forced outages.

There is no real benefit to the market in having refunds that are set too high. They do provide additional revenue to retailers but as a wind-fall they cannot be relied upon to offer lower prices to customers. Refunds should be just large enough to work and no higher.

Kind regards

Patrick

Patrick Peake

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From: Patrick Peake
Sent: Friday, 11 May 2012 3:52 PM
To: Allan Dawson; Market Admin
Cc: Courtney Roberts
Subject: Reserve Capacity Mechanism Working Group

Hi Allan

Just following up on my previous email in respect to the Reserve Capacity Mechanism Working Group.

One issue that does worry Perth Energy is the volatility that has been experienced with the Reserve Capacity Price. This is perceived by our financiers to increase the risk associated with investing in generation plant which in turn can raise costs and prices. One suggestion has been to allow the RCP to vary so as to signal whether additional capacity is required but to quarantine, at least partially, the RCP for generators that are already in the market. We do not have any proposed mechanism to do this but raise it as an issue for consideration.

Regards

Patrick

Patrick Peake

General Manager Western Energy

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From: Steve Gould
Sent: Wednesday, 18 April 2012 7:09 AM
To: Allan Dawson; Suzanne Frame
Subject: Comments of RCMWG issues

Hi Allan and Suzanne.

Please see below my thoughts on the RCMWG issues.

Regards

Steve

<u>RCM Review</u>

1. The existing mechanism has successfully incentivized new entry of Generation and DSM.
2. The IMO Board prefers that the mechanism be adjusted rather than restructured.
3. The MRCP has recently been substantially reduced and the consequences have not yet manifested. The indications are that this is deterring new investment. The ERA's WACC for Western Power's Access Arrangement indicates further downward pressure on the MRCP.
4. Substantial block-loads are being developed that could manifest relatively suddenly compared to the timescale for building new generation.
5. It is likely that the participation of DSM has at best saturated, and it is possible that this will reduce due to the 'harmonisation'
6. Lantau's proposal:
    a) Is incremental and doesn't require provision for transition
    b) Avoids aggravating the price-shock still working through the mechanism
    c) Enhances the incentive for new capacity when there is little excess capacity
    d) Enhances the disincentive for new capacity when there is significant excess capacity

While the "110%" and "-3.15" are subjective, they seem to me to be reasonable and the outworking has a good look to it.

<u>'Harmonisation'</u>

This work is at an early stage and I look forward to specific and substantiated recommendations from the consultant.

I would also suggest:

1. inclusion of the testing and proof of availability requirements. In particular, I note that if a scheduled generator has to achieve the (temperature-adjusted) certified output for return of its security deposit and in order to avoid capacity refunds. Thereafter, if it does not self-dispatch to the temperature-adjusted certified output every 6 months, it is issued with a real-time Dispatch Instruction without notice and may have its capacity credits suspended if it fails to perform on two consecutive occasions. I perceive that DSM is subject to less onerous obligations.

2. Consideration of methods of permitting DSM to participate in Balancing and, subject to support from DSM participants, ancillary services. While I support the initial exclusion of demand-side from the Balancing Mechanism in order to simplify the process, I perceive that the DSM participants are becoming sophisticated and should be encouraged to fully participate, especially for baseload customers. In particular, the metering issue seems to me to be no more onerous that that arising in respect of Intermittents when dispatched to turn-down.

LGP

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11 May 2012

Mr Allan Dawson
Chief Executive Officer
Independent Market Operator
Level 3, Governor Stirling Tower
197 St Georges Terrace
PERTH WA 6000

Dear Allan

REVIEW OF THE RESERVE CAPACITY MECHANISM

Alinta Energy (Alinta) appreciates the opportunity to provide comments to the Independent Market Operator (IMO) on draft consultants' reports in connection with a review of the Reserve Capacity Mechanism (RCM).

Alinta is an Australian energy company with interests in ten power station assets, which are diversified by geographic region, fuel type, customers and operating mode. Alinta also supplies gas and electricity to around 700,000 retail, commercial and industrial (C&I) and small to medium enterprise (SME) customers in Western Australia, South Australia and Victoria, and employs more than 750 people across Australia and New Zealand.

These comments are made by Alinta for and on behalf of Alinta Sales Pty Ltd, which is a wholly-owned subsidiary of Alinta. Alinta Sales Pty Ltd is registered as both a Market Customer and a Market Generator in the WEM.

Alinta's view

Firstly, it appears that the significant increase in the 'oversupply' of capacity from 2012/13 to 2013/14 is primarily due to a downward revision in the IMO's forecast of the Reserve Capacity Requirement (RCR) for that year rather than the entry of new capacity.

That said, Alinta supports the 'harmonisation' of obligations that apply to capacity providers, including in terms of availability and maximum duration, and minimum dispatch notification period.

As discussed at the first meeting of the Reserve Capacity Mechanism Working Group (RCMWG), it would appear necessary to clearly define the desired characteristics of capacity offered to the market (i.e. the terms and conditions or obligations on which capacity must be made available to the market). To the extent this highlights a need to 'harmonise' divergent obligations imposed on different capacity providers, this should occur as a priority.

If the obligations imposed on capacity providers were completely 'harmonised', there is the potential that some capacity may choose to exit the market. If it were concluded such an outcome were not in the market's best interests, an additional class (or classes) of capacity could be created. This would then enable capacity providers to self-select the class in which they wished to provide capacity to the market (and hence their obligations).

To the extent that the different obligations reflected in a difference in the 'value' that each class of capacity provided to the market, an adjustment would then be required to either the quantity of capacity (i.e. as already occurs for capacity provided by intermittent facilities) or the price paid for the capacity.

As noted above, there is the potential for the future level of 'surplus' capacity to be affected by the 'harmonisation' of capacity obligations. Further, the impact that the significant recent fall in the Maximum Reserve Capacity Price (MRCP) may have on the entry of new capacity entry is as yet unknown.

Finally, there is no analysis of the impact that more aggressively reducing the Reserve Capacity Price (RCP) might have on incentives facing potential providers of capacity and/or retailers. Without such analysis, it is unclear whether the proposed approach might be effective in efficiently reducing an 'oversupply' of capacity.

For these reasons, Alinta does not consider it desirable at this time to contemplate increasing the rate at which the RCP declines when available capacity exceeds the RCR.

Background

The broad design principle underpinning the WA Wholesale Electricity Market (WEM) is for participants to bilaterally contract for energy. There are also a number of opportunities (e.g. the STEM and the soon to be introduced Balancing Market) to facilitate trading around contracted bilateral positions.

It appears that the original market design also contemplated that capacity would be predominantly bilaterally contracted. Within that design, it appears that the anticipated role of the Reserve Capacity Mechanism (RCM) was simply to overcome some of the problems associated with the 'lumpiness' of projects providing new capacity.

While the design of the RCM appears to have changed from that originally contemplated, both designs appear to facilitate (smaller) Market Customers (i.e. retailers) transferring risk and costs to the market and energy consumers as a whole. This occurs as Market Customers can avoid contracting bilaterally for peaking energy and capacity, the need for which is highly uncertain, and instead pay the IMO for such capacity and purchase the energy if, and as, required from the market.

Overtime, as the certainty and/or price and/or amount of energy that needs to be purchased from the market increases, it will become less risky and less costly for the Market Customer to increase its bilateral contracts for capacity and energy.

Under both the original and current design of the RCM, it appears that (energy or non-energy) peaking capacity would be most likely to enter the market either without a bilateral contract or via a Reserve Capacity Auction.

Leaving aside demand side management (DSM) capacity, it appears that 230MW of generation capacity (Perth Energy's Western Energy and Merredin Energy projects, and Tesla's 9.9MW distribution connected generators) has entered the market on a completely uncontracted basis, relying solely on the Reserve Capacity Price (RCP) paid by the IMO to support their commercial viability. This capacity represents around 10 per cent of new capacity that has entered the market since 2006/07.

The recent decrease in the Maximum Reserve Capacity Price (MRCP) by around 30 per cent, which returns it to 2010/11 and 2011/12 levels, suggests the ability to finance a project solely based on the RCP paid by the IMO has not changed materially, but may in fact have deteriorated marginally in real terms.

Since market start in 2006/07, around 390MW of DSM capacity has entered the market, the bulk (350MW) in the last three years. Overall, the amount of capacity provided by DSM has increased by 350 per cent, and this form of capacity represents around 17 per cent of new capacity that entered the market since 2006/07.

The increase in DSM capacity appears to have effectively offset a fall in capacity provided by peaking open cycle gas turbines (OCGT). The proportion of capacity provided by OCGTs has fallen almost 7 per cent, while that provided by DSM has increased by just over 5 per cent. When these 'peaking' forms of capacity are combined, in aggregate they still represent slightly less than 50 per cent of system capacity.

Table 1 Capacity Credits assigned by primary fuel type

	2006/07		2013/14	
Base	1,489.000	39.8%	2,203.478	36.2%
Mid	227.000	6.1%	551.800	9.1%
Peak - energy	1,817.075	48.5%	2,625.338	43.1%
Peak - non-energy	111.000	3.0%	499.786	8.2%
Intermittent	100.325	2.7%	206.427	3.4%
Total	3,744.400	100.0%	6,086.829	100.0%

Source: http://www.imowa.com.au/f180,1430115/Capacity_Credits_since_market_start_-_EMC_thru_13-14.pdf and Alinta estimates

Lantua reports

Two of the key issues to be addressed by the RCMWG are the '*consistent capacity surpluses secured in the WEM*' and '*the pricing of capacity in oversupply conditions*'.[1]

In relation to these issues, the Lantau Group recommended amending the formula for calculating the RCP. It has since prepared two reports for the RCMWG that propose and develop an option whereby the formula for deriving the RCP, which is the price paid by the Independent Market Operator (IMO) for any capacity that is not bilaterally contracted and which has effectively become a floor price for capacity, would be '*more responsive to market conditions*'.

However, the option proposed by Lantau, being to simply increase the rate at which the RCP declines when available capacity exceeds the RCR, does not directly address what appears to be the underlying issue in the market design that might be contributing to consistent over supply of capacity.

[1] http://www.imowa.com.au/f5415,2189080/RCMWG_Terms_of_Reference_FINAL.pdf

Specifically, the design of the RCM has changed from that originally contemplated, and it appears that at least in part the changes made may have contributed to the consistent over supply of capacity seen to date.

However, it is not clear that the original design of the RCM would not have similarly resulted in excess capacity. This is discussed further below.

Reserve Capacity Mechanism Design

It appears that the designers of the WEM had originally intended that new capacity would **only** enter the WEM via the RCM if that capacity was:

- subject to a bilateral contract between Market Participants (e.g. a Market Generator and a Market Customer); **or**
- procured by the IMO via a Reserve Capacity Auction and subject to a Long Term Special Price Agreement (LTSPA) between the Market Participant and the IMO.

  The Market Rules specify that the price for capacity procured by the IMO via an auction and subject to a LTSPA would be capped at the Maximum Reserve Capacity Price (MRCP).

For example, the Wholesale Electricity Market Design Summary, dated September 2006, under a section headed 'Reserve Capacity and Generator Investment Strategies', comments that (p.37):[2]

> *…if an existing facility's capacity has not been traded bilaterally and that facility fails to win a place in an auction then its owner will have two years to assess what to do. After that time it will cease receiving Reserve Capacity payments, but will be allowed to continue participating in the market.* ***However, without a Reserve Capacity payment, either from the auction or via bilateral trade, the facility may no longer be economically viable. This is an appropriate outcome, because the fact that the facility's capacity has not been traded bilaterally or cleared in the auction suggests that the market can acquire new capacity at a lower cost*** *[emphasis added].*

And further (p.38):

> *Pre-conditions for a new facility that is yet to be commissioned to be certified to provide Reserve Capacity will include a letter of offer for an access agreement from its Network Operator and evidence of any necessarily environmental approvals. While this may take some time to obtain,* ***holding a bilateral contract for Capacity Credits allows Market Participants to commit to building new facilities in the knowledge that once they have secured all necessary approvals they will be able to secure the benefits of the Reserve Capacity regime*** *[emphasis added].*

It is possible that the original RCM design may not have resulted in consistent capacity surpluses. This is due to the following reasons.

- It is unlikely that Market Customers would voluntarily and consistently contract for capacity significantly greater than that required to meet their Individual Reserve Capacity Requirement (IRCR) – to do so would place a retailer at a cost disadvantage to other retailers.

2 http://www.imowa.com.au/f149,2037717/MarketSummarySeptember2006.pdf

- It is unlikely that the IMO would have procured capacity significantly and consistently greater than that required to meet the capacity shortfall (i.e. the gap between the Reserve Capacity Requirement (RCR) and the aggregate amount of capacity that was bilaterally contracted).

However, it appears possible that the original design might have resulted in greater risk of capacity shortfalls, while the design also appears to potentially result in capacity surpluses from time-to-time.

- The 'lumpy' nature of generation facilities may have made it difficult for Market Customers (i.e. retailers) to contract for additional capacity in increments required to meet the growth in their load (i.e. IRCR).
- The consumption profile of temperature dependent loads and the generally short term nature of retail electricity contracts (of between two and three years) may have discouraged Market Customers from entering into long term bilateral contracts for all of its capacity obligations (i.e. IRCR).
- As a result, there may have been a relatively high reliance on the IMO to procure capacity via auctions. There would appear to be a risk that an auction process, run in September two years before the capacity would need to be available to the market, might not be effective in consistently securing significant amounts of capacity (given planning and approval timeframes), or alternatively that the two year timeframe would preclude the entry of capacity provided by facilities other than open cycle gas turbines (OCGT) and intermittent generators (e.g. wind) (both presumably with planning and other approvals already in place) or non-energy forms of capacity (such as demand side management).
- While the original RCM design may have resulted in capacity being secured from facilities with lower capacity costs, it appears that the cost of energy provided by such facilities would have been higher. It also appears likely that the total cost of capacity and energy would have been higher than for a base load generator that could not be developed within the auction timeframe.
- At some point, when the frequency and/or probability that energy would be required to be provided to the load exceeded a particular threshold, a Market Customer would be incentivised to bilaterally contract for additional, most likely base load, capacity and energy, rather than remain uncontracted and meet its share of the IMO's (higher cost) Targeted Reserve Capacity Cost.
- As the IMO would have entered into a (10-year) LTSPA with any capacity procured via an auction, the market as a whole would have been required to pay for any surplus capacity via the Shared Reserve Capacity Cost – although the highest cost capacity procured by the IMO would have been allocated to the Targeted Reserve Capacity Cost.

This suggests that while the RCM design as originally contemplated may still have been accompanied with capacity surpluses from time-to-time.

Given the consequences associated with capacity surpluses and shortages are unlikely to be symmetrical (i.e. the potential consequences of capacity shortages are demonstrable worse than in the case of a capacity surplus), it appears appropriate that the design of the RCM was amended to reduce the risk of capacity shortages.

Capacity Price

Implied in the scope of works of the RCMWG is the notion that it is '*the pricing of capacity*' that has contributed to *'the consistent capacity surpluses secured in the WEM*'.[3]

The original RCM design contemplated that the price for capacity would be either negotiated between Market Participants (if capacity were bilaterally contracted) or between Market Participants and the IMO (if capacity were procured via an auction).

While the Market Rules capped the price that could be paid by the IMO under a LTSPA for capacity procured via an auction at the MRCP, there was no cap on the price for capacity that might be bilaterally negotiated. Nevertheless, it is apparent that the designers assumed that a bilaterally negotiated capacity price would be **lower** than the price that would be paid by the IMO under a LTSPA for capacity procured via an auction (which was to be capped at the MRCP).

For example, the Design Summary notes that Market Customers that did not hold sufficient Capacity Credits would be required to fund the Targeted Reserve Capacity Cost in proportion to their Capacity Credit shortfall. It commented that (p.36):

> *…*
>
> *Because of Special Price Arrangements, not all Capacity Credits cost the IMO the same amount, so the most expensive mix of Capacity Credit costs will be recovered via the Targeted Reserve Capacity Cost.*
>
> *…*
>
> *The purpose of this Targeted Reserve Capacity Cost* [capped at the MRCP] *is to provide an incentive for Market Customers to contract bilaterally for capacity well before it is required, and to contract with reliable providers.*

Under the original RCM design, capacity that was not bilaterally contracted could never be certain of success in an auction. Consequently, while the original RCM may have led to capacity being paid a higher price if it were procured by the IMO via an auction (i.e. up to the MRCP), the inherent uncertainty of being successful in an auction versus a capacity shortfall being priced at an expected higher Targeted Reserve Capacity Cost is likely to have incentivised Market Participants to bilaterally contract.

Further, a key feature of the original RCM design is that irrespective of the route to market (i.e. via a bilateral contract between Market Participants or between Market Participants and the IMO), the provider of capacity would have **price certainty** for a defined period. If the capacity was procured by the IMO via an auction, it would have price certainty (in real terms) for a period of 10 years by virtue of the LTSPA.

In contrast, the current design of the RCM provides for the IMO to pay for capacity despite that capacity not being bilaterally contracted nor procured via an auction. While the price paid by the IMO for this capacity, the RCP, cannot exceed 85% of the MRCP, it is guaranteed and hence effectively represents a price floor.

[3] http://www.imowa.com.au/f5415,2189080/RCMWG_Terms_of_Reference_FINAL.pdf

Unlike under the original design of the RCM, capacity that is not bilaterally contracted but is paid the RCP by the IMO does not have price certainty. The RCP will change annually as a result of changes in the value of market parameters used to establish the MRCP, may change due to changes to the methodology for calculating the MRCP (as has occurred recently), and (since the 2008 Capacity Year) is adjusted for capacity in excess of the RCR.

Nevertheless, while the current RCM may result in an uncertain price for uncontracted capacity, it does provide a certain revenue stream (i.e. there is some uncertainty about the level of payments, but the capacity provider will receive payments). The certainty of revenue, when combined with the ability to avoid counter party credit risk, effectively decreases the incentive for capacity to be bilaterally contracted. Providers of capacity no longer face the risk that their capacity will be stranded (i.e. there is no longer a risk of being unsuccessful in an auction), and purchasers of capacity are assured that the Targeted Reserve Capacity Cost will not exceed the RCP (provided sufficient capacity is voluntarily made available).

While the potential volatility of the RCP (for the preceding reasons), may create some incentive to bilaterally contract on the part of the provider of capacity, this incentive must be weighed against the credit risk to which it would then be exposed.

Conversely, given the total cost of capacity incurred by retailers does not change under the current RCM design (as the price adjusts in a case of oversupply), there is currently also little incentive to retailers to bilaterally contract for capacity other than base load capacity that also provides energy.

[An exception would be a large retailer, like Synergy, whose customers are most likely to experience the adverse consequences of retailers transferring risk to the market by not contracting bilaterally for peaking energy and capacity, and instead paying the IMO for such capacity and purchase the energy if, and as, required from the market. As a large retailer's customers are most likely to be adversely affected if there is a shortfall of energy, it will be incentivised to contract for peak capacity.]

Adjusting the rate at which oversupply of capacity will decrease the RCP paid by the IMO potentially strengthens the incentive for capacity providers to bilaterally contract for capacity but is unlikely to create a stronger incentive for retailers to bilaterally contract. This is because while the total cost of capacity may fall, to the extent that retailers bilaterally contract, they forgo an opportunity to share in these lower costs.

As with the original RCM design, at some point the frequency and/or probability that energy will be required by load will exceed a particular threshold, incentivising the Market Customer to bilaterally contract for additional, most likely base load, capacity and energy, rather than continue to pay the IMO for the same level of uncontracted capacity via the Targeted Reserve Capacity Cost

Table 2 Capacity Credits assigned by primary fuel type (detail)

	Market Start		Additional Capacity								Current		
Type	2006/07	*Portion*	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	*Sub total*	2012/13	*Portion*	*% increase*
Coal	1,096.000	*29.3%*	-	215.000	207.000	-	23.800	224.000	5.500	*675.300*	1,771.300	*29.1%*	*61.6%*
Distilate	66.200	*1.8%*	-1.087	7.177	-2.095	1.545	7.074	99.636	11.600	*123.850*	190.050	*3.1%*	*187.1%*
DSM	111.000	*3.0%*	20.000	-2.895	-29.460	54.855	106.600	194.386	45.300	*388.786*	499.786	*8.2%*	*350.3%*
Gas-CCGT	227.000	*6.1%*	-	323.000	1.800	-	-	-	-	*324.800*	551.800	*9.1%*	*143.1%*
Gas-CoGen	393.000	*10.5%*	-	56.210	-41.210	6.540	9.460	4.178	4.000	*39.178*	432.178	*7.1%*	*10.0%*
Gas-OCGT	1,750.875	*46.8%*	350.080	-110.615	361.860	58.780	1.004	16.417	6.887	*684.413*	2,435.288	*40.0%*	*39.1%*
Landfill	21.300	*0.6%*	-	-1.145	37.885	-0.670	-0.401	-40.025	0.058	*-4.298*	17.002	*0.3%*	*-20.2%*
PV	-	*0.0%*	-	-	-	-	-	-	2.733	*2.733*	2.733	*0.0%*	*na*
Wind	79.025	*2.1%*	-	-0.250	0.775	1.070	87.399	3.535	15.138	*107.667*	186.692	*3.1%*	*136.2%*
Total	3,744.400	*100.0%*	368.993	486.482	536.555	122.120	234.936	502.127	91.216	*2,342.429*	6,086.829	*100.0%*	*62.6%*

Source: http://www.imowa.com.au/f180,1430115/Capacity_Credits_since_market_start_-_EMC_thru_13-14.pdf and Alinta estimates

It is therefore not apparent that adjusting the rate at which oversupply of capacity will decrease the RCP paid by the IMO would either eliminate the consistent capacity surpluses secured in the WEM or would strengthen the incentive for capacity providers to bilaterally contract for capacity.

Investment in new capacity

Implied in the scope of works of the RCMWG is the notion that it is '*the pricing of capacity*' that has contributed to the *'the consistent capacity surpluses secured in the WEM*'.[4]

The IMO published on its website Capacity Credit information on a facility-by-facility basis since the commencement of the WEM. This information is summarised in the table on the previous page.

Comparing this information with that in Table 1 of Lantua's second report (10 April 2012), it appears that approximately 230MW of generation facilities entered the WEM without an underlying bilateral contract for capacity and/or energy:

- Western Energy, 109MW OCGT – 2010/11
- Merredin Energy, 82MW distillate – 2012/13
- Tesla, 4 x 9.9MW distillate – 2012/13

These facilities represent approximately 10 per cent of new capacity provided to the market since commencement, with demand side programmes accounting for a further 17 per cent of new capacity.

The entry of the 320MW OCGT Newgen Neerabup facility in 2009/10 was partly underwritten by Synergy[5], which as noted earlier is most likely to be the only Market Participant that has an incentive to bilaterally for capacity that is able to provide peaking energy.

Other than Griffin's Bluewater 2 facility, the bulk of the remaining new capacity entered the WEM where contractually underwritten by the Government, either via Synergy or Verve Energy.

- Newgen Kwinana, 320MW CCGT – 2008/09 (Synergy)
- Griffin Power, 204MW coal – 2008/09 (Synergy)
- Griffin Power 2, 204MW coal – 2009/10 (Boddington)
- Verve Kwinana, 185MW OCGT - 2011/12
- Verve/Vinalco, 220MW coal – 2012/13

In its second report (10 April 2012), Lantau comments that:

> *…the RCM is the only mechanism left in the SWIS (other than government direction through Verve) to drive new investment in non-intermittent facilities. ... 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.*

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4 http://www.imowa.com.au/f5415,2189080/RCMWG_Terms_of_Reference_FINAL.pdf

5 http://www.mediastatements.wa.gov.au/ArchivedStatements/Pages/CarpenterLaborGovernmentSearch.aspx?ItemId=127114&minister=Logan&admin=Carpenter

However, this statement does not appear to be strictly true. As previously noted, as the current design of the RCM provides for the IMO to pay for capacity despite that capacity not bilaterally contracted nor procured via an auction, that price, the RCP, effectively constitutes a price floor.

Whether future investments in capacity other than peaking capacity will be commercially viable will depend on when the frequency and/or probability that energy will be required by load will exceed a particular threshold. At that point, a Market Customer will be incentivised to bilaterally contract for additional, most likely base load, capacity and energy, rather than continue to pay the IMO for the same level of uncontracted capacity via the Targeted Reserve Capacity Cost. This is because the price of capacity paid to the IMO plus the (probability weighted) cost of energy purchased from the market will be higher than the cost of capacity and energy provided by a base load generator.

It appears that the RCM can only ever be an effective mechanism for ensuring there is sufficient peaking capacity.

Should the IMO require further information on any of the above issues, I can be contacted on 9486 3749.

Yours sincerely

Corey Dykstra
Manager Wholesale Regulation
Alinta Energy (for and on behalf of Alinta Sales Pty Ltd)

Harmonisation should focus on the needs of System Management

Demand Side Programmes (DSPs) and generation resources have inherently different characteristics. As such, they can never be exactly equivalent on every technical parameter. There are some metrics on which generation is superior (such as firm availability during non-peak hours), while there are others on which DSPs are superior (such as the lack of line losses and independence on fuel supplies).

In considering any changes to "harmonise" DSPs with generation, we believe the goal should be to pursue rule changes that materially improve the ability of System Management to use DSPs when they are needed. This means looking at options that are driven by system requirements and improve the ability of System Management to reliably utilise DSPs at the top of the load duration curve and during other grid emergency operating conditions.

The primary issue at present, in our view, is that System Management does not have the confidence to call a DSP if they think they need it early in the season – they are concerned that it may be better to save it for later, due to the limited number of hours for which it can be called during the capacity year. Further, they are not confident of what response they will see whenever they do call it.

To resolve these issues, EnerNOC proposes several specific changes to the rules, each designed to increase the utility of DSPs for system reliability and System Management dispatch purposes.

EnerNOC supports a move to a single Availability Class for DSPs

EnerNOC is supportive, in principle, of the suggested move to a single DSP service with a higher level of availability than the current minimum of 24 hours per year. Such a move, we believe, will improve System Management's ability to use DSPs. The determination on DSP service availability should be driven by system requirements, and we do not believe perceptions relating to the quantity of DSM in the market nor a desire for pure equivalency with generation should influence this determination.

As noted in the Sapere Report:

> *"DSM is relatively expensive to dispatch – the cost of dispatching DSM includes the opportunity cost to participating loads of reducing their consumption which for many loads can be significant. Due to the high cost of dispatch, it is efficient for DSM to be last on the dispatch merit order."*

Given this principle, coupled with the fact that currently DSPs can effectively be last in the WEM's dispatch merit order (assuming they bid to the Alternative Maximum STEM Price Cap), it is important to look at the load duration curve. In our view, both a) the total amount of DSM in the market, and b) the performance requirements of DSPs should make sense in light of the requirements dictated by the load duration curve.

Table 1 below summarises actual load duration data for the WEM from the 06/07 Capacity Year through the 10/11 Capacity Year. A review of the data indicates that the percentage of demand during the highest 48 hours of the year has ranged from 8.3% to 15.9%. We believe the amount of DSM currently in the market (8.2% of RCM Capacity Credits in 2013/14) is reasonable given the SWIS's historical load duration.

Table 1: SWIS Load Duration 2006/07 to 2010/11

Load Duration Curve	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Demand (MW)	**3,414**	**3,426**	**3,536**	**3,775**	**3,784**
Top 24 Hours					
% of Peak Demand	10.6%	5.9%	9.5%	7.4%	5.5%
Top 48 Hours					
% of Peak Demand	15.9%	8.3%	13.0%	11.7%	9.2%
Top 72 Hours					
% of Peak Demand	18.1%	10.5%	15.3%	14.2%	11.2%
Top 96 Hours					
% of Peak Demand	19.9%	12.4%	16.9%	16.0%	13.0%

Load data downloaded from WEMS and based on the EM_OperarLoad Report and DSM results from the IMO.

In addition to the analysis above, EnerNOC's experience leads us to believe that there is a natural limit to the amount of DSM that will ultimately participate in any capacity market. This "DSM Ceiling" is based as much on the technical limits inherent in the curtailable load to be found in the Commercial & Industrial sector as it is on the requirements dictated by the load duration curve.

Table 2 below summarises the current registered DSM capacity in three of the major, relatively mature, capacity markets in the United States. The amount of DSM in these markets, which ranges from 6.7% - 8.6%, is very much in line with the current amount of DSM capacity in the WEM.

Table 2: Total DSM load registered by selected market

Market	Capacity (MW)	Share of Demand
PJM	14,118	8.6%
NYISO	2248	6.7%
ISO-NE	2164	7.4%
IMO-WA	469	8.8%

Sources:

PJM 2014/15 Base Residual Auction Results, Doc #645284, page 9. 14,118.4 MW of DR Cleared in the RPM.

PJM 2014/15 RPM Base Residual Auction Parameters, Doc #631095, pg 2. Forecasted peak of 164,758 MW

NYISO's Demand Response Programs. Donna Pratt, Manager Demand Response Products. May 2011.

NYISO Press Release, 22 July 2011. Peak demand reached 33,454 MW on 21 July 2011.

Forward Capacity Auction 5 (FCA5, 2014-15) Results Summary, ISO New England, 2011.
ISO Installed Capacity Requirements, PAC Meeting. ISO New England, July 2011. Compares cleared FCA5 MW to the CELT 2011 Forecast 50/50 Peak of 29,380 MW for 2015 Capability Year.

WA: Summary of Capacity Credits for the 2011 Reserve Capacity Cycle (October 2012-2013), IMO, Sep 2011

WA: Ibid. Compares cleared DSM capacity to the Reserve Capacity Requirement of 5,312 MW.

We also think it is important to consider the load forecasts in the 2011 Statement of Opportunities. Table 3 below summarises this data, which indicates that the current DSM capacity in the market (499MW in 2013/14) would be required for slightly less than 48 hours annually if it were dispatched by System Management to match exactly those intervals at the top of the load duration curve.

Table 3: WEM Load Forecasts

2011 SOO Forecast (MW)	2012/13	2013/14	2014/15
Maximum Demand	**4,635**	**4,802**	**5,219**
Less than 24 hours	**426**	**412**	**413**
Less than 48 hours	**519**	**522**	**525**
Less than 72 hours	**594**	**600**	**588**
Less than 96 hours	**631**	**653**	**629**

2011 Statement of Opportunities Report - Data from pg 44

With respect to defining the Availability class for DSPs, we believe that the key consideration relates to the number of hours System Management requires to reliably support SWIS peak duration.

Dispatch Rules need to be considered in tandem with DSP Availability

In other capacity markets, there is an explicit trigger mechanism used to determine when to dispatch DSPs. These are typically based around either forecast or actual operating reserves: where they fall below a particular threshold, then DSM is called upon. Such DSM trigger mechanisms exist in the ISO-NE, NYISO and PJM markets today. We believe such mechanisms are an extremely important check in the system that ensures DSM is only called upon when it is needed.

EnerNOC understands the WEM Rules, as currently constructed, provide the functional equivalent to such a trigger mechanism through the dispatch merit order. As highlighted previously, the rules place DSPs last in the dispatch merit order provided DSPs bid their dispatch prices at the Alternative Maximum STEM Price cap. Theoretically, therefore, the current mechanism acts as an equivalent to a reliability-based trigger mechanism.

However, EnerNOC does seek clarification about whether its understanding is entirely accurate, or whether there remains any System Management latitude that could envisage DSPs being dispatched “out of order”, and for reasons other than defined system reliability conditions.

DSM restrictions are not binding for most conceivable dispatch events

There are restrictions on the dispatch of DSM, such as business days, consecutive hours, consecutive days, and notice periods. These seek to strike a sensible balance between usefulness to system management and practicality for providers: if these requirements were excessively onerous, it would be unattractive for many consumers to provide demand response; if they were too loose, system management would not find DSPs to be useful.

We believe that the current settings strike a reasonable balance: they make DSM useful to system management in addressing most conceivable extreme events, without making it impossible to find providers who are able to comply.

But DSM can still be there when the inconceivable happens

Customers, i.e. those who are the actual providers of demand response, have demonstrated in many other markets that they are willing to act as a “last line of defence” to keep the lights on. Indeed, in various studies of the reasons why customers participate in such programmes, “helping to avoid blackouts” or “civic responsibility” often ranks among the top reasons for participation.

While a DSP may not be able to deliver its full capacity commitment outside the defined program requirements, many providers within these DSPs are likely able to do better than the minimum requirements – i.e. respond for longer, or on more consecutive days, or more quickly. Ideally, if the circumstances are such that System Management needs these extra capabilities due to an unforeseen system emergency, they should be able to request them.

EnerNOC believes the rules should be amended to enable System Management with the ability to call DSPs on a “best efforts” basis outside of a DSP’s defined availability arrangements. With regards to the issue of consecutive days, we understand that the original 2008 working group’s intent was to enable a third consecutive day’s dispatch on a “best endeavours” basis, that is, removing the prospect of penalties for the unlikely third day in a row. Translating this intent within the market rules has resulted in DSPs capacity obligation dropping to zero for the third consecutive day, preventing System Management from being able a DSP at all.

This “best efforts” practice is commonplace in other major capacity markets, and experience has demonstrated that DSPs can and will deliver a significant percentage of their capacity obligation when called outside their defined availability period.

An effective approach would be for System Management to be able to issue dispatch instructions that go beyond the limits specified in a DSP’s performance requirements. When this occurs, the DSP should attempt to comply, but if it does not entirely manage to do so, it should not be subject to normal penalties.

Enabling DSPs to respond on a “best efforts” basis outside its program arrangements recognises also that DSPs face Capacity Refunds that are, per unit of failure, much tougher than those faced by generation facilities.

Table 4 below shows the Capacity Refunds that would be payable by three different facilities (a 24-hour DSP, a 96-hour DSP, and a generator) for failing to deliver 1MW of capacity during a 4-hour dispatch event. The penalty is based on the 2011/12 capacity price, and the penalty due is shown for both a peak hour dispatch and an off-peak dispatch.

Table 4:

	DSP (24 Hours)	DSP (96 Hours)	Generation
During DSM Program Hours (12-8pm)	$21,967	$5,492	$366
Off-Peak Intervals	$0	$0	$61

Calculation based on a 30-day month.
Refund multiplier faced by generators is assumed to be 6.0 for peak intervals and 1.0 for off-peak intervals.

In peak intervals, during which the vast majority of dispatches are likely to occur, **a 24-hour DSP currently pays a penalty that is 60 times higher than that faced by a generator**. This example clearly demonstrates that the current Capacity Refund risk faced by DSPs is significantly higher than that faced by generators.

System Management should be able to see DSP Availability & Performance

In line with seeking changes that improve the ability of System Management to reliably utilise DSPs, EnerNOC believes the value of telemetry needs to be considered. System Management does not currently have any visibility into the availability and performance of DSPs. This makes them less confident than they should be about relying on DSPs. In particular, it makes it difficult for them to anticipate the change in load they will see when dispatching DSPs. It also means that they are likely to dispatch the full capacity of all the DSPs available to them, rather than use a more graduated response, matching the dispatched DSP capacity to the severity of the problem.

Some concerns have been articulated that too much demand response provided at once over the system peak can have the effect of “saturating” the system, creating two peaks where before there was only one. Clear visibility into the amount of DSP capacity available, combined with the flexibility to dispatch it more consistently with real-time needs would allow System Management to make more efficient use of the DSPs, reduce impacts on real-time prices, and effect greater consistency with generation dispatch.

It is possible for DSPs to provide some level of telemetry to System Management. Given the distributed nature of DSPs, the performance specifications for the telemetry have to strike a balance between the benefits to System Management and the implementation cost and practicality for DSPs. ISO-NE is a precedent for this, requiring telemetry with 5 minute updates, which is typically delivered in aggregated form via the internet. It is our view that a reasonable level of telemetry to System Management should be required of all DSPs participating in the market.

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11th May 2012

Griffin wishes to provide comment on Reserve Capacity Mechanism issues discussed by the RCMWG to date: Excess capacity on the SWIS and the Reserve Capacity Price as a solution; and DSM (harmonisation).

Preface:

The objective of the Reserve Capacity Mechanism (RCM) is to encourage Reserve Capacity (RC) development such that total RC stays appropriately ahead of the 10% POE peak load demand. The RCM provides an investment incentive as it a reliable revenue stream designed to assist the long term recovery of capital investment.

Griffin notes the IMO's clearly stated position is that the IMO is not attempting to address the relationship between reserve capacity, the (likely) load factor of certified capacity, and the relationship between those and energy prices.

The intent of the design of the WA WEM was to ensure adequate capacity; however it was also co-designed as a Bilateral-based market, with energy price limits.

Griffin Power foresees higher energy prices as the current mechanism has encouraged an influx of non-bilaterally contracted, low load factor capacity which has evolved into a shallow energy market.

Demand Side Management:

Griffin supports the proposal to more closely align the deliverables and requirements of DSM to that of generation capacity, in keeping with the market objective to avoid discrimination against any form of particular energy option.

More generally the 'discrimination' rule should be interpreted to better reflect its intent → that there be no discrimination in the application of RC requirements in terms of qualification, certification and treatment thereof. This then creates a level playing field which any (current or future) capacity technology must meet in order participate in this capacity market. This could be achieved by relaxing the conditions and criteria that generation capacity is bound to abide by, or tightening the criteria and obligations of DSM capacity.

Griffin acknowledges that DSM has an important role to play in the WA WEM capacity market by providing an additional capacity flexibility to respond to generation supply shortfalls. Griffin also notes that DSM broadly has the lowest entry cost to the market, the lowest load factor, and the lowest performance requirements. It also has the shortest lead times to enter, and exit the market – a feature of the technology the WA WEM should utilise to find cost effective capacity, or shed costly capacity, when appropriate.

- Griffin proposes consideration be given to a cap of 300MW (or some other justifiable reserve) on DSM certified reserve capacity where:
  a) that capacity is not bilaterally contracted, and
  b) there is more than 10% excess reserve capacity on the SWIS. It is not justifiable, or economically efficient, to make payments to DSM capacity where there is virtually no chance the service will be called into play - it is an unnecessary expense to the market;

  and where DSM certification priority is provided through System Management driven criteria (Eg. Generation Class (available hours), size of DSM, and response times etc).

  - Generation Classes:

    - Griffin proposes the minimum available hours of all Generation classes that receive <u>100% capacity payments</u> per MW be set at 96 hours.

  - DSM Response times

    - The maximum DSM response time should be no longer than 250 minutes (4 hours 10 minutes)

<u>Excess reserve capacity:</u>

Griffin does not agree that the current excess of RC is a direct result of (upward) forecasting errors because Griffin does not see evidence or, or a correlation between, SOO load forecasts and the macro decisions by corporations to invest (over the last 4-5 years).

Griffin does agree that additional, low capacity factor, reserve capacity, has undoubtedly been encouraged by a higher RCP (and the perception that the RCP would always increase). Griffin further asserts that a high RCP encourages capacity investment with no genuine incentive or intent to bilaterally contract.

Griffin notes that DSM capacity is further encouraged by higher levels of excess RC, since the chance of being called is ever-decreasing.

- In order to counter the current levels of excess RC Griffin supports the proposition that the RCP be reduced at a greater rate than currently exists. Griffin would support the concept of a transitional phasing in of the higher degradation payment rates.

Griffin notes a general level of unease and uncertainty caused by the volatility of administered Reserve Capacity Price (RCP). This application of such variable prices is near impossible to counter and the uncertainty will likely impact future investment decisions. While the calculation of the RCP is out of scope, the RCP volatility itself is not well aligned with the broad concepts of a utility industry. The price, like the product, should be relatively reliable & predictable – the mechanism should discourage large price swings from year to year.

- Griffin proposes that regardless of the price mechanism upheld at the conclusion the RC review, that a cap on total downward volatility be introduced on a year-to-year basis to avoid financial failings of corporates as a result of downward price shocks.

- The assignment of Capacity Credits is apparently driven by a prioritisation process and related to the Bilateral Trade Declaration. As there is apparently no cap on the levels of RCR, Griffin would like to question the purpose of any ‘prioritisation’ criteria. Can the IMO address the intent of the ‘prioritisation’ of capacity proposals which is performed prior to the certification of RC?

It appears to be widely acknowledged, and accepted, that participants merely state their *intent* to bilaterally trade in order to tick a required box. This is a a key criteria for certifying RC, yet its application is woefully neglected.

- Griffin suggests more rigorous development and application of the rules in this respect are clearly appropriate.

- Griffin suggests the RCM WG consider that (in a market with an excess reserve capacity expected to hit ~15% in 2013/14) the activation of the prioritisation process to certify new capacity based on evidence of Bilateral **Energy** contracts - a pseudo-spigot which is activated when excess capacity exceeds 10% (or some other properly determined figure). This is a criteria not unlike the fuel-supply requirements; a criteria which is closely related to energy production and a criteria in keeping with the intended Bilateral nature of the market.

Andrew Stevens
Manager – Energy Trading

Over Supply of Capacity and DSP Harmonising

1.0 Oversupply of capacity

1.1 General concerns regarding oversupply

In general terms Synergy sees the oversupply of capacity as something which interferes in the normal activities of retailing. If retailing can be taken as contracting for energy and capacity to bundle into offers to customers, then the oversupply of capacity breaks this relationship. As an example, the spreadsheet that was forwarded to the working group members showed that the more a retailer contracts for capacity to cover its liability the greater the resulting cost. The spreadsheet showed that the optimal contracting point is zero capacity, meaning all capacity should be purchased from the IMO and not bilaterally contracted. This reality is clearly in conflict with that of a bilateral market and not a practical outcome.

Synergy's preferred resolution in addressing the oversupply of capacity is not necessarily to remove the oversupply, or that the resulting capacity price is reduced, but that the existence of overcapacity does not impact upon the retailer's capacity liabilities. A retailer is able to hedge its capacity liability such that it is able to offer fixed prices, which customers want. Synergy's preferred solution is that a retailer's capacity liability should solely depend upon the sum of its customer's demands and not the volume of credited capacity variations in SWIS demand forecast or intensities of summer demands or large loads expected to arrive but did not. Synergy would prefer to contract for all of its own capacity to meet the demand of its customers, including a defined security margin, but not be subject to an additional liability resulting from the over supply of capacity. This is why Synergy consders the working group should consider its suggested 'market based pricing approach for capacity crediting' which was circulated to the working group members in April 2012. In summary the proposed market based approach delivers:

- Capacity making a bilateral trade declaration is ineligible from receiving an IMO reserve capacity payment;
- Undeclared capacity goes into an auction which would set the clearing price; and
- If no auction then a high administered price would be set by the IMO to facilitate for capacity trades and allow the refund mechanism to function.

Synergy proposed this market based pricing approach to create a reserve capacity price derived from competitive processes; to reinforce the bilateral contracting nature of the market; to place the capacity risk in the hands of retailers and not the IMO; and to remove the cost of capacity oversupply as a shared cost. Synergy believes this approach does not turn off the tap of capacity, but allows new more efficient capacity to arrive. This would simply happen even if existing retailers had full capacity books by allowing a new retailer to win market share using the new efficient capacity. In this case oversupply could exist but that oversupply is not smeared over the market instead residing with particular retailers contracting with high cost or inefficient capacity.

1.2 Mike Thomas's design – price slope adjustment

Synergy sees Mike Thomas's design as a useful starting point, an interim step in evolving the reserve capacity mechanism from its current oversupply condition to a leaner capacity credited condition. Synergy agrees with Mike Thomas' comments that this approach would reduce the volume of oversupply, encourage bilateral contracting but is not sustainable needing a more permanent resolution. For Synergy, resolving oversupply by simply adjusting price is a second best approach which in reducing the price can effectively devalue existing bilaterally capacity contracted. The approach potentially creates more volatility in the capacity price than desirable and places too much authority in the hands of the IMO in determining the slope factor and RCP/MRCP ration to be considered any more than a transitionary solution.

This approach, if adopted, may discourage the oversupply of capacity but may also fail to increase bilateral contracting of capacity. If nothing else can be agreed then Synergy is prepared to consider this approach for a time, but would require the working group to continue its activities to develop and implement a permanent solution, not leaving such decisions to a future review. Synergy's preferred approach is Mike Thomas's interim approach quickly evolve into a market based solution rather than linger using administrative pricing mechanism to try and control the volume of capacity.

A number of working group members have raised concerns regarding Mike Thomas's proposal. Synergy believes these concerns can be dealt with during a design phase. In saying this, one problem the design must account for is how to ensure that the minimum generation requirement, effectively availability class 1 capacity, is satisfied as the price drops due to oversupply and encourages generators to depart.

1.3 Determining the reserve capacity requirement – focussing on forecasts

The IMO is aware that retailers unbundle capacity as a component in their bills rather than fix a price for their customers. This is a consequence of the capacity cost exposure being too large a risk for a retailer to bear therefore having to pass this risk on to its customers. Unfortunately oversupply is not the only cause of capacity cost risk and so fixing oversupply is unlikely by itself to lead retailers to bundle capacity in their bills. Another significant cause of capacity cost risk relates to the variation in the whole process of forecasting the capacity need and translating this in to an individual reserve capacity requirement. So the following is a brief comment on some aspects of the problem and potential directions to assist the working group's discussing on this topic.

Synergy holds the view that the oversupply of capacity is not just that part of capacity above the reserve capacity requirement but starts with an inherent oversupply resulting from using the 1 in 10 approach and locking in capacity two and a half years before it is used. The following table shows the 1 in 10 forecasts of capacity published in the statement of opportunity (SOO) and calculates the MW difference between the capacity year setting the forecast and the most recent forecast.

Capacity Year	2008 SOO in MW	2009 SOO in MW	2010 SOO in MW	2011 SOO in MW	Forecast Difference MW
2010/11	4,700	4,397	4,346		354
2011/12		4,725	4,793	4,458	267
2012/13			4,986	4,635	351

Besides the revised forecast reducing the closer it gets to the actual capacity year, Synergy questions the relevance of the 1 in 10 year forecast itself. Actual system peaks have been consistently less than the 1 in 10 forecasts for example; the most recent summer being 2011/12 had the 1 in 10 forecast, as given in the 2010 SOO, almost 900 MW higher than the actual peak demand of 3900 MW. In responding to this one may point out that a 1 in 10 event has not occurred so the market's need for capacity has not been truly tested. Although this view contains truth, Synergy holds that the 1 in 10 forecast may be a much rarer event and using it as the baseline provides too much capacity particularly given that the full capacity requirement also includes an extra 8.2% of capacity for contingencies plus allowances for intermittent load and load following services.

The point is that the current forecasting approach and the action of locking in all of the capacity quantity two and a half years in advance of a capacity year has greatly contributed to the oversupply of capacity through consistent over forecasting. Synergy would suggest that the wholesale electricity market take some guidance here from other markets, for example PJM, by not locking in the full forecast volume two and a half years before, but instead lock in progressively an increasing amount. For instance, after the starting forecast is published the IMO would not be required to credit the full expected need for capacity as currently happens, instead the IMO may only credit up to, say, the 90% POE (excluding new block loads) an amount of capacity the market is confident will be needed which also minimises any consequences of forecast error. More capacity would be progressively credited using revised forecasts closer to the start of the relevant capacity year.

One advantage of a progressive capacity crediting is that it could commence earlier than the current two and a half years timetable avoiding any risk of a bad forecast.

2.0 Harmonisation of Demand and Supply Side Sources

2.1 Harmonise a technical comment

Synergy interprets the concept of "harmonising" as using different ingredients combined to achieve a desired outcome. Given this definition, Synergy sees harmonising, in relation to reserve capacity, not as a process of forcing different capacity types to assume the same or similar characteristics, but rather arranging those components so they contribute in their own unique way to delivering the desired outcome. The desired outcome for Synergy has two parts: one being the technical delivery of reliability and the other being at a reasonable cost.

2.2 The technical part

In a technical sense, Synergy sees harmonising as what is needed from different capacity types and availability classes, such that the Reserve Capacity Requirement is met and the reliability of supply complies with the provisions in clause 4.5.9(b). Harmonising in a technical sense is answering the question what is the:

- minimum number of hours required for availability classes 2 to 4;
- the minimum hours needed for each event; the number of sequential days required; and
- the hours of availability needed each day.

Market rule clause 4.5.9(b) already answers the question of technically harmonising for availability class 1 but the job is only undertaken in a simple load duration curve approach for the remainder.

Synergy's suggestion for this technical harmonising is to expand the assessment used to determine the minimum quantity of generation capacity to the remaining availability classes. For availability class 1 the 0.002% energy not served criteria is used to model the minimum quantity of generation capacity to account for plant failure and plant maintenance. In this technical sense, the RCM review needs to ensure that all availability classes are credited such that they can meet the underlying energy requirement related to their segment of the load duration curve[1]. This extra assessment is not to determine the capacity volume which is the purpose of the minimum generation modelling but to determine when availability classes 2 to 4 need to be available.

In determining the minimum notice period for DSPs, Synergy would suggest choosing a period that would reasonably reduce the number of wrong dispatches and the volume error of the dispatch.

2.3 The cost part

In discussing the cost part, one is suggesting ways to reduce the current cost of capacity placed upon the market. The Mike Thomas proposal is clearly something which should impact upon cost in reducing the cost related to excess capacity by reducing the capacity price. Other ways to reduce the cost of capacity are to entertain either differential pricing of capacity or differential crediting.

[1] This modelling cannot simple use the load duration curve but will need to use the relationship in demand between hours for peak demand days.

Over Supply of Capacity and DSP Harmonising

Differential pricing means paying DSP capacity in a different way to generator capacity. This would mean that DSP get a lower reserve capacity payment reflecting their lower availability compared to a generator. Differential crediting means only a portion of a capacity credit is issued for each MW of DSP demand offered. The purpose in adopting either of these two approaches is to reduce the cost of capacity derived from capacity types with lower fixed costs than a peaking generator on which the reserve capacity price is based, less flexible/limited dispatch arrangements and as a way to deliver better value to those ultimately paying the cost of capacity, being the retail customers.

Although differential pricing in particular appeals to Synergy the savings expected by maintaining a lower price to certain capacity types such as DSPs would quickly evaporate as bilateral contracting re-values all capacity (which the market endeavours to treat as a single generic product but simultaneously allows sub types to have different attributes such as availability) to the same price. In other words, trying to maintain differential pricing with a single capacity product is difficult. So, instead of considering differential pricing, Synergy suggests that the working group consider different types of capacity credits being applied to the each of the four availability classes. Under such an arrangement there would be four individual reserve capacity requirements one for each availability class, each with potentially different payment structures reflecting their requirements. This approach allows capacity credited in availability class 4 to be offered a different price (lower price) to that of availability class 1 without this payment being re-valued through the bilateral contract process.

Regarding differential crediting this concept appears difficult to design given the question how does one choose the level of crediting to be applied to DSPs without such appearing to be arbitrary. One approach for consideration by the working group in setting a reduced credit value is to recognise that the market gives, in Appendix 3, priority to availability class 1 allowing this class, if in oversupply and committed, to be allocated to the other lower availability classes. The suggestion is that the reduction in credit value is determined by the volume of DSP capacity to be credited. For instance if twice the volume of availability class 4 is credited compared to what the volume to meet the hour range x being: 0>x<48 then the resulting credit value would be halved. Given the current oversupply of availability class 1 it is likely that the remaining availability classes will be filled from this class and so the resulting worth of a DSPs capacity credit could be low or even zero

RCMWG Meeting 3 Action Point from Brendan Clarke

RCMWG Members to provide feedback to the IMO on the proposed sliding scale determination of Reserve Capacity Price.

Lantau Presentation

I believe the key issue is that excess capacity increases the cost to the market as over capacity is paid for by retailers via the shared reserve capacity payment mechanism. That is a retailer who is fully contracted in capacity must pay for excess capacity at the Reserve Capacity Rate.

Lantau comments *"Consequently, we favour a price-based adjustment either driven by more use of auctions (complex implementation and more volatile value impacts), or a sharpened RCP price adjustment formula".*

I agree with this comment

I feel steeping the curve appears to only treat the symptom not address the cause This option simply reduces the amount of the extra payment.

I favour the price based adjustment option albeit it may be more complex. I see the use of more auctions as favourable, but requires some new rules to be put in place. For example I suggest the maximum reserve capacity price is a true maximum not the clearing price. For example if all bids are at zero then the price is zero and all. With out this a competitive price can not be revealed.

Additionally I favour a different auction for each availability class. It seems to me that the best new entrant capacity costs associated for a 60 hour availability is less than that of an open cycle gas turbine.

RCMWG Members to provide feedback to the IMO on the proposed solutions for harmonisation of demand and supply side sources

Sapere Presentation

DSM

Sapere commented upon

"Need for harmonisation
• *All capacity resources provide same basic function*
• *Capacity credit is a common unit*
(1 MW of DSM = 1 Capacity Credit = 1 MW of generation)"

I believe this premise only holds if procurement and payments are the same.
As above commented on the Lantau Presentation I suggest that this need not be the case.

If the harmonisation philosophy holds then the differentials have been sufficiently documented but also needs to include the restriction on only callable on 2 consecutive days. The D1 and D2 preliminary options are feasible

FUEL

I believe this is a good starter for an issues list.

The S1 & S3 options are feasible. The S2 option appears to reduce system security so I do not favour this option.

INTERNATIONAL CAPACITY MARKETS

A.1 BACKGROUND

A "Capacity Market" generally refers to a market system that delivers an administered system of payments to generators in return for providing reserve capacity in order to satisfy demand in the event that it exceeds scheduled supply. The precise mechanism by which payments vary according to the specifics of the market design but all markets are designed to reflect the degree of excess demand such that the level of payments increases with the level of reserve required. At times of surplus capacity, capacity payments will be small, while at times of inadequate capacity, they have the potential to be large. We note that this is much less true of the WA market than of the other markets surveyed here, and is a point of difference.

A.2 THE ORIGINS OF CAPACITY PAYMENTS

Systems designed to ensure generation security and adequacy through centrally-administered capacity payments have a broad international history. In addition to the US markets studied in this report, examples can be found in the UK (before the new trading arrangements (NETA)), Spain and several Latin American countries, among others. A common feature of all centrally administered capacity markets is that they incorporate payments for generating plant based on their availability regardless of whether they are dispatched.

All liberalised electricity systems around the world recognise the need for centralised provision and control of ancillary services procured by the system operator. However, mechanisms for ensuring the availability of such services differ and may include either auction based markets, long term contracts with generators or more directive measures such as market rules insisting on a given level of reserve margin.

In some cases market participants are allowed to self-provide certain ancillary services but the quantities are dictated by the system operator who is also the provider of last resort for these services. With respect to long-term reserves, however, there is considerable diversity in reliance on market-based approaches and the debate over which is the correct way of ensuring generation adequacy is yet to be settled. In California, for instance, where the initial market design relied on a pure market solution for provision of generation adequacy, the capacity shortages experienced in 2001 prompted proposals for an available capacity requirement (ACAP) to be imposed on load serving entities.

Discussions concerning the appropriate form of regulatory intervention in generation adequacy assurance are also taking place in Texas where currently generation reserves are plentiful. FERC's Notice of Proposed Rulemaking (NOPR) on Standard Market Design (SMD) also recognised the need for load serving entities (LSEs) to ensure the supply of power to their customers through adequate contracted provision of capacity reserves.

A.3 THE PENNSYLVANIA-NEW JERSEY-MARYLAND SYSTEM

A.3.1 History and Background

The Pennsylvania-New Jersey-Maryland System (PJM) is the largest centrally dispatched electric power system in North America. It pools the generation and transmission facilities of over 500 utilities in 13 states and the District of Columbia. As an Independent System Operator (ISO), it operates a voluntary bid-based wholesale electricity market, manages the high-voltage electricity grid across the region, administers the fixed transmission monthly auction market and provides ancillary services. The PJM serves more than 51 million people and has administered over US$110 billion in electricity billings since the liberalization of the energy markets in the U.S.[1]

In 1997, the implementation of the Open Access Transmission Tariff led the PJM to introduce a competitive electricity market. This required the PJM to make significant changes to the way in which capacity obligations were met. Previously, Load Serving Entities (LSE), e.g. distributors to final customers, determined their loads and capacity obligations on an annual basis. When combined with regulatory requirements on plant investment, the PJM system maintained sufficient capacity and had a reliable pool, with costs of capacity obligations born equally by the LSEs and their loads.[2]

The liberalization of the energy sector however required that PJM meet capacity obligations through market mechanisms. While a competitive market created opportunities for new entrants to serve the retail market, LSEs also had to meet PJM's reliability criteria. New LSEs now needed a way to acquire capacity credits gained through a competitive process. Likewise, existing LSEs needed a way to sell capacity credits no longer needed if load was lost to new competitors. The PJM introduced a series of arrangements that later became known as the Installed Capacity (ICAP) market that was intended to balance the supply and demand for capacity. In 1998, monthly and multi-monthly capacity markets were developed. In 1999, daily capacity markets were installed and bilateral transactions on capacity were allowed.[3] Bilateral contracts enabled PJM members short on capacity to buy from members with excess capacity and a capacity credit was used to reflect the sale and purchase of rights to capacity.[4]

In 2007 however, the ICAP market was replaced with the Reliability Pricing Model (RPM). The RPM was meant to address key market design flaws in the previous system that resulted in inadequate infrastructure investment and poor energy resource management.[5] The following section discusses the ICAP market and RPM model in further detail, providing an overview of their market design, assessing their performance and ability to overcome the various market issues.

A.3.2 The Installed Capacity Market at PJM

Overview of Market Design

Several key features provided a framework for operating the supply-side ICAP market.

1 http://www.pjm.com/about-pjm/who-we-are.aspx, accessed 19 August 2009.

2 2001 State of the Market Report.

3 Creti, Anna and Fabra, Natalia, *Capacity Markets for Electricity*, 26 November 2003.

4 FERC Docket No. EL01-63-000, dated 5 April 2001.

5 http://www.pjm.com/markets-and-operations/rpm.aspx, accessed 19 August 2009.

- First, when the generators sold capacity resources to the PJM LSEs, they also sold LSEs a right to recall energy destined to be provided to customers outside the PJM control area. This feature enabled PJM to recall energy exports from capacity resources in cases of emergencies. Under a recall circumstance, the supplier is paid the prevailing PJM energy market price.[6]
- Second, the capacity resources that the generators produced could be de-listed or exported from the PJM control area or imported from generators outside the PJM control area. If a generator opts to de-list, it is no longer obliged to meet the capacity requirements set by the PJM.
- Finally, owners of capacity resources were required to offer their output into the PJM's day-ahead energy market. The purpose of this is to ensure that when LSEs purchased capacity that it will be available on a daily basis and not just during emergencies. Because day-ahead offers are financially binding, resource owners had to provide the offered energy at offer price. This energy is either sourced from a specific generating unit, or if unavailable, purchased from the energy spot market.[7]

The LSE's capacity obligation was determined by the Reliability Assurance Agreement (RAA) that required LSEs to have capacity resources greater than or equal to the expected peak-load plus a reserve margin. The reserve margin is in turn based on a reliability analysis performed by the PJM and on requirements set forth by the North American and the Mid-Atlantic Reliability Councils. For the PJM-West region, capacity obligations were defined daily while for the PJM-East region, capacity obligations were defined annually.[8] LSEs had to own or acquire capacity resources to meet its capacity obligations. These capacity resources could be purchased using three methods:

- *Bilateral Basis*: Generators could sell all or part of a specific generating unit to another utility within the PJM control area. These sales could also be in the form of a capacity credit, defined in terms of unforced capacity and measured in MW.
- *Interval Markets:* PJM operated a daily, monthly, multi-monthly capacity credit markets that facilitated the exchange of capacity credits among system members.
- *External Transactions:* LSEs could import capacity from outside the control area so long as it conformed with PJM's criteria. These criteria included the requirement that imports were from specific units and sellers have firm transmission from these units to metered boundaries of the PJM control area.[9]

In the case that an LSE fell short of capacity and failed to submit a bid to the capacity market, a current capacity deficiency rate (CDR) is charged. The proceeds from these CDRs were split among all LSEs with capacity in excess of their capacity obligations and generators that were not load serving. Likewise, if the LSE complied with its capacity obligation, then it would also be entitled to revenues from the CDRs (if any).[10] As of April 2001, the CDR was $177.30 per MW per day.[11]

6 *Ibid.*

7 *Ibid.*

8 FERC Docket No. EL01-63-000, dated 5 April 2001.

9 2001 State of the Market Report.

10 Creti, Anna and Fabra, Natalia, *Capacity Markets for Electricity*, 26 November 2003.

11 FERC Docket No. EL01-63-000, dated 5 April 2001. The capacity deficiency charge is calculated by dividing the rate for the deficiencies on an installed basis of $160 per MW per day by a factor equal to (1 – pool forced outage rate) for a planning period. The outage rate at that time is .0976.

ICAP Performance

It became apparent in the years following the implementation of the ICAP market that there were multiple design flaws. First, capacity sales that were not bound by location undermined the very objective of the ICAP market, which is to provide sufficient capacity and reliability. Second, the CDR enabled capacity sellers to exercise monopoly positions and drive capacity prices higher than a competitive price. And third, because the ICAP market resulted in highly volatile capacity credit prices, it also adversely affected incentives for new plant investment. The paragraphs below discuss each of these design flaws in greater detail.

A.3.3 Generator De-Listing

As market based sellers, generators were not bound by location and would simply sell to the market with the highest price. Because utilities were historically integrated and had a responsibility to ensure reliability, this had not previously been a problem. However, after the liberalization of energy markets and more companies began divesting generation, the primary LSEs that were concerned most about reliability began controlling less generation in the PJM. Under the ICAP market rules, individual capacity owners had the right to “delist” capacity, declaring that it was no longer a capacity resource in the PJM. This reduced firm energy available to serve PJM loads and therefore hindered reliability standards.

In 1999, before there were substantial divestitures, this flaw had little effect on the PJM. In fact, capacity resources exceeded capacity obligations from anywhere between 500 MW and 3,000 MW during that year. In the second half of 1999, system net excess capacity averaged about 1,800 MW. In 2000 however, multiple generation divestitures coupled with high energy prices created incentives for generation owners to delist from the PJM. On June 1, 2000, the capacity resources in PJM were less than the total capacity obligation and prices in the PJM daily capacity credit markets reached the highest level since the ICAP market’s inception, yet failed to attract capacity offers due to the high spot price of energy in neighbouring markets. The large spread of external energy market prices over PJM market prices provided a profitable opportunity for owners of uncommitted capacity in PJM. During this time, exports spiked to nearly 2,500 MW, when it ranged between 0 and 500 MW during other times during that year. Table below provides a comparison of PJM forward prices and external forward prices.[12]

Table 1: Comparison of External Forward Prices vs. PJM Forward Prices

	June 2000			**July - August 2000**		
	Minimum	Maximum	Mean	Minimum	Maximum	Mean
PJM	52.6	100.0	63.7	57.0	140.0	97.5
External	60.3	125.0	70.9	131.5	207.5	155.5
Difference	(0.8)	35.0	6.6	34.1	81.0	51.6

Source: 2000 State of the Market Report

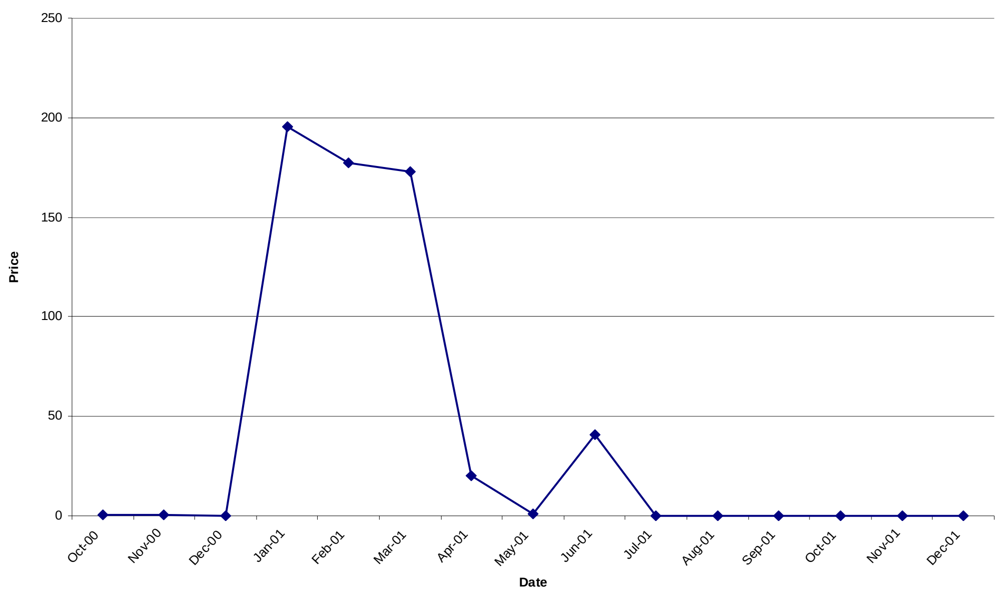
12 2000 State of the Market Report.

A.3.4 Market Power Abuse

The ICAP market design also enabled large generators to exercise market power. Given that LSEs were required to purchase a fixed amount of capacity, large suppliers realised that if they withheld only a small amount of capacity from monthly auctions that they could substantially increase prices. These large price increases more than offset revenues lost as a result of withholding the resources.

Figure shows the PJM weighted average daily price from between October 2000 and December 2001. Beginning in January, the capacity credit price rose from nearly zero to $177 on January 1 and 2, and increased up to $354 on January 3rd and then remained at $177 through late March. Prices reached a high of $354/MW-day because capacity market rules required that a deficient party must pay twice the CDR on a day when the overall market is deficient and which required mandatory bids at twice the CDR for any deficient party.

Figure 1: PJM Capacity Credit Market Weighted Avg. Daily Price ($/MW)



Two market conditions gave rise to this outcome. First, the seller was able to offer more total capacity in the daily market than the total net capacity requirements of the market. And second, the seller's offer of capacity was greater than the daily demand for capacity less the capacity offered by other suppliers. As a result, LSEs, who had to cover capacity obligations, had to buy capacity from this seller. The seller was therefore able to offer it's unsold capacity at a price greater than or equal to the CDR of $177.3/MW-day, forcing LSEs short of capacity to be either deficient and pay the CDR or purchase the capacity credits at a price equal to the CDR.[13]

In response, the PJM modified the capacity market rules that would remove the incentive to withhold capacity in order to receive CDR revenues. They did so by implementing an interval market that provides LSEs with an incentive to meet their obligations to serve load on an interval basis and provides generators with incentives to sell capacity on an interval basis.[14]

13 "Report to the Pennsylvania Public Utility Commission: Capacity Market Questions," Market Monitoring Unit, November 2001.

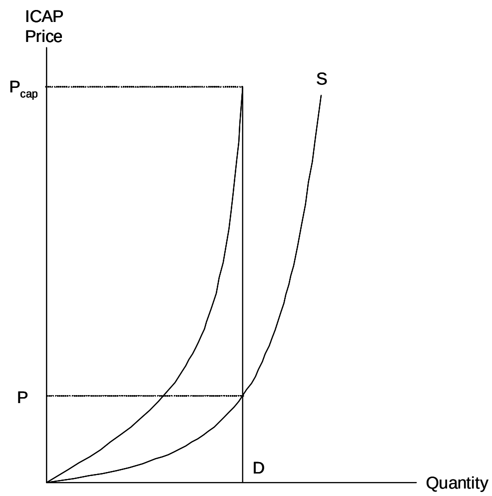
14 2001 State of the Market Report

A.3.5 The "Missing Money" Problem

Finally, the ICAP market in the PJM did not provide adequate incentives for investment in new infrastructure and generation. Because the capacity prices in ICAP market could vary between very low (near zero) price and very high prices at deficiency, it created high risks for buyers and investors of energy. When there were surpluses, which tended to be at most times in the PJM market, capacity prices ranged anywhere from zero to approximately US$0.05. However, when there were just slight shortages of capacity as was the case in the spring of 2001 and the summer of 2004, the weighted average daily capacity price was nearly always above US$100. Thus, while prices might be high in one month, addition of new plants in another month may drive prices down to nearly zero, making the recovery of the investors' fixed and capital costs highly uncertain.[15]

This can be best explained using a simple supply and demand illustration. The highly volatile capacity prices were the result of the demand curve, which did not represent the buyer's willingness to pay for capacity but fixed by capacity obligation. This is represented by a vertical line corresponding to the amount of installed capacity needed to meet the region's target reserve margin (which was about 15 percent of projected peak demand). The supply curve was defined by the price offered by generation suppliers. The intersection of capacity supply and the vertical administrative demand curve was then the monthly price for ICAP. Figure 1 illustrates how the ICAP design causes highly volatile prices.

Figure 1. Price Volatility in the ICAP Market



A.3.6 The Reliability Pricing Mechanism

Overview of Market Design

On June 1, 2007, the RPM Capacity Market design was implemented, entirely replacing the ICAP market. The RPM market design represents a significant change from the older system with several key features including annual capacity obligations, a locational market, and performance incentives for generation.

15 2001 and 2004 State of the Market, "PJM's Reliability Pricing Mechanism: Why It's Needed and How it Works,", PJM, March 2008.

- *Annual Capacity Obligations*: The RPM eliminated the use of the interval capacity auction system and instead requires forward capacity commitments for at least a one year period. By doing so, the PJM is able to eliminate incentives by generators to make daily decisions regarding whether and where to sell capacity and thereby ensuring adequate capacity and reliability.
- *Locational Pricing*: RPM prices are locational and may change depending on varying demand and transmission constraints in different geographies. Transmission constraints into one particular area may restrict access to lower cost supply, thereby causing high whole sale prices. Previously, the PJM provided uniform payments to all generators in the PJM control area whether or not there were transmission constraints. This became an increasingly evident problem as locations with severely limited transmission were not receiving investments needed. The RPM solution enables capacity payments to differ across geographies within the PJM, with higher capacity payments in locations with transmission constraints and lower payments in locations without transmission constraints.
- *Performance Incentives for Generators*: The RPM improves energy resource management by creating incentives for energy to be available during hours where demand is highest. Under the ICAP system, generators were paid for installed capacity, providing little incentive to make units available during high demand hours. However, under the RPM system, capacity payments are not only made based on installed capacity, but also capacity available during hours where the PJM system is short on reserves.[16]

Auction Mechanism

The RPM is a multi-auction structure designed to procure resource commitments to satisfy the regions unforced capacity obligation through the following market mechanisms: a Base Residual Auction, Incremental Auctions and a Bilateral Market

- Base Residual Auction - The Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. The Base Residual Auction allows for the procurement of resources to satisfy the regions unforced capacity obligation and allocates the cost of those commitments among the Load Serving Entities (LSEs) through a Locational Reliability Charge.
- Incremental Auctions ‿ Up to three Incremental Auctions are conducted after the Base Residual Auction to procure additional resource commitments needed to satisfy potential changes in market dynamics that are known prior to the beginning of the Delivery Year.
- The Bilateral Market ‿ The bilateral market provides resource providers an opportunity to cover any auction commitment shortages. The bilateral market also provides LSEs the opportunity to hedge against the Locational Reliability Charge. The bilateral market is facilitated through the eRPM system.

Treatment of demand side

PJM has three types of Load Management products:

- Direct Load Control (DLC) – Load management that is initiated directly by the resource providers market operations ***centre*** or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners).

16 "PJM's Reliability Pricing Mechanism: Why It's Needed and How it Works,", PJM, March 2008.

- Firm Service Level (FSL) – Load management achieved by a customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the resource providers market operations ***centre*** or its agent.
- Guaranteed Load Drop (GLD) - Load management achieved by a customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the resource providers market operations ***centre*** or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

For each type of recognized Load Management Product, there can be two notification periods:

- Step 1 (Short Lead Time) – Load management which must be fully implemented in one hour or less from the time the PJM dispatcher notifies the market operations centre of a curtailment event.
- Step 2 (Long Lead Time) – Load management which requires more than one hour but no more than two hours, from the time the PJM dispatcher notifies the market operations centre of a curtailment event, to be fully implemented.

Loads must be able to drop for six hours every day (different hours are specified depending on the season. This is substantially more (over a year) than the DSM requirements in WEM.

RPM Performance

One of the primary objectives of implementing the RPM was to encourage new investment in energy infrastructure in the PJM. An independent study mandated by the PJM confirmed that during the first five RPM auctions, over 4600 MW of existing generation had been retained that would have retired and that 3,274 MW of new generation has been committed in the RPM auctions as a result of the implementation of RPM. The PJM Market Monitoring Unit also states that existing generators have committed to at least US$5 billion in investment over the 5 year period of RPM auctions.[17]

A.4 New York Independent System Operator

A.4.1 History and Background

The New York Independent System Operator (NY-ISO) was established in 1997 and formally began its operations in 1999 after the liberalization of U.S. electricity markets. Its predecessor was the New York Power Pool, a consortium of eight investor owned utilities. Today, the NY-ISO manages New York's bulk electricity grid, operates the wholesale electricity market, conducts long-term reliability planning to evaluate customer demand and acts as an independent source of information on key energy issues. Its location also means that the NY-ISO serves as a critical point for the transfer of electricity to and from the Northeast U.S. and Canada. NY-ISO's gross revenues of market transactions were US$11.4 billion in 2008 and market revenues since the inception of the NY-ISO total over US$70 billion.[18]

17 "Quantifying the Cost of the Reliability Pricing Model," PJM 2008.

18 "Connection," New York ISO, Winter 2009.

Like the PJM, the liberalization of the electricity markets in the U.S. resulted in New York's ICAP market beginning in 2000. The ICAP market was developed to ensure that sufficient installed generating capacity would be available to meet projected loads in three main locales, New York City, Long Island and the greater New York Control Area. New York's ICAP market, like the other markets, is based on the obligation placed on LSEs to procure ICAP to meet minimum requirements. Two additional features, including a locational aspect ("LICAP") with individual demand curves and an Unforced Capacity ("UCAP") methodology of determining the supply of capacity, sets it apart from the earlier designs of ICAP markets. The NY-ISO recently began discussing a move toward a Forward Capacity Market like the one found in the New England ISO (to be discussed next). In the sections below, we provide an overview of the NY-ISO ICAP design, assesses their performance and ability to overcome the missing money problem, and describes various design modifications that are being considered in the latest reform discussions.

A.4.2 Market Design Overview

While the basic structure of New York's ICAP market is similar to earlier designs of U.S. ICAP markets, New York adopted a UCAP method of capacity procurement in addition to locational capacity requirements to ensure that adequate energy resources are always available. The NY-ISO uses a UCAP methodology to determine the amount of capacity that each generator is qualified to supply to the New York Control Area (NYCA), and to determine the amount of Capacity that LSEs must procure. The UCAP methodology estimates the percentage of load that a generator is capable of serving, taking into account forced outages. A rolling 12 month average of monthly forced outage rates is used to determine the amount of ICAP that can be sold in units of UCAP.

In addition, locational capacity requirements differentiate the value of generation resources based on location and overall contribution to resource adequacy. In locales such as New York City where severe transmission constraints limit the physical ability to transmit power into high energy demand areas, capacity requirements are an important measure used to maintain system reliability. The New York State Reliability Council ("NYSRC") uses the ICAP demand curve in each locality and considers the impact of inter-zonal transmission constraints in determining locational requirements. In the Locational ICAP ("LICAP") market, LSEs may meet their capacity requirements through self-supply, bilateral contracts or auction participation. In the auction process, LSEs submit bids to buy capacity and generators on the other hand submit offers to sell capacity during each Commitment Period, defined as each 6-month summer and winter period.

The NY-ISO uses three methods to conduct the auction process:

- First, the Capability Period Auction is 6-month strip auction that provides forward capacity for the full 6 month period.
- Second, the Monthly Auction provides forward capacity for each remaining month in a period.
- And third, the ICAP Spot Market Auction clears only a few days before the month begins and provides LSEs with a final opportunity to meet capacity obligations without penalty. Three ICAP demand curves are used in the ICAP Spot Market Auction to determine the locational component of LSE Unforced Capacity obligations in each of the three NY-ISO localities. The NYRC in turn is responsible for overseeing the auction process and ensuring that LSEs purchase sufficient capacity to meet their load plus a reserve margin.[19]

19 NYISO Installed Capacity Manual, April 2009.

A.4.3 LICAP Performance

The market issues found in New York's LICAP market are very similar to those found in the early designs of the ICAP in the PJM market. That is that the LICAP market fails to provide sufficient incentive for investors to build new energy infrastructure in New York. Initially, the LICAP auction was only designed to ensure sufficient generating capacity for several months at a time. However, an investor may want a form of a forward contract to sell energy for ten years in order to receive financing to build a new generating unit. While one may recognise this as an issue, LSEs on the other hand are typically unwilling to commit to long-term contracts given the difficulty in projecting the number of customers these LSEs are required to service in the future.

Another deficiency of the LICAP market in incentivizing investment has to do with the volatile UCAP prices.

Beginning in June 2003, the NY-ISO implemented a demand curve to the auction process with the objective of ensuring that auction revenues were sufficient to cover the capital costs of building a peaking plant. Under this revision, the bids of LSEs in the spot LICAP auction are replaced by a specified demand curve set by the regulators. For each location, the demand curve is an aggregate of the capacity requirement for each location, ensuring that the market price of capacity is equivalent to the capital cost of a peaking unit when the total amount of capacity purchased is equal to the amount needed for adequacy. The market price will be higher (lower) if the total capacity offered is lower (higher) than the required amount.[20]

Despite NY-ISO reforms, the performance of LICAP has been poor in terms of incentivizing investment in new generation where needed despite high levels of capacity payments in New York. **Error! Reference source not found.** shows the amount of capacity payments made to owners of existing generators in the NY-ISO area. In 2006 and 2007, over $1 billion in capacity payments were made[21], yet investors have continued to delay construction on new infrastructure. One reason for this may be that earnings from capacity auctions continue to remain too volatile and does not provide enough financial security to make substantial capital investments. That is, despite the high capacity payments that have been evidenced, investors may only opt to make investments where multi-year Power Purchase Agreements ("PPA") are available.[22]

Table 2: 2006 - 2008 NY-ISO ICAP Payments

	Actual $'000	*Pro-Rated $'000*
2006 - NYC	654,251	1,017,328
2006 - LI	34,245	351,732
2006 - ROS	363,420	754,575
2006 Total	**1,051,916**	**2,123,635**

20 Ibid.

21 The merger of National Grid and KeySpan in 2008 created conditions that decreased capacity payments in 2008.

22 Maneevitjit, Surin and Mount, Timothy, "The Evolution of Capacity Markets in the USA"

	Actual $'000	Pro-Rated $'000
2007 - NYC	680,086	1,038,455
2007 - LI	35,042	426,686
2007 - ROS	378,967	783,004
2007 Total	**1,094,095**	**2,248,145**
2008 - NYC	291,804	454,765
2008 - LI	19,739	132,959
2008 - ROS	343,156	670,287
2008 Total	**654,699**	**1,258,011**

A.4.4 New Reforms

The NY-ISO is currently discussing moving towards the development of a Forward Capacity Market similar to that found in the NE-ISO (to be discussed next). The market design currently being discussed involves a multi-year, multi-part auction process that would begin up to six years ahead of the commitment year when a voluntary auction would be run for interested buyers and sellers. Another voluntary auction would be run the following year, five years ahead of the commitment year. The primary auction would be a Forward Procurement ("FP") auction that would occur roughly four years before the effective period. While 100 percent of the capacity would be purchased in this auction, LSE's would be able to purchase incremental amounts above the 100 percent level. Like the current market design, generators would not be required to participate though they would also risk not receiving revenues.

During the three-year period leading up to the commitment year, the NY-ISO would administer several physical reconfiguration auctions to account for changes in the load forecast and potential failures of qualified capacity and offer voluntary reconfiguration auctions to allow voluntary auction buyers and sellers to settle their positions. A strip auction would then be administered at the beginning of the capability year, with a spot auction occurring at least twice per year.[23]

A.4.5 Role of Demand

The New York Market has three load- management programs. These programs offer differing terms and payments, and are open to all types of customers.

The **Installed Capacity Special Case Resources** (ICAP SCR) is a reserve capacity program that contracts resources to meet NYISO supply requirements over a specified contract period. This is the demand response which bids into the capacity market in New York.

The **Day-Ahead Demand Response Program** (DADRP) is a customer- initiated economic bidding program, where participants offer their load reduction into the wholesale market a day in advance. This demand response bids into the energy markets of New York.

23 "Connection," New York ISO, Winter 2009.

The **Emergency Demand Response Program** (EDRP) is a short-notice program relying on the ability of many to voluntarily reduce their demand for a short period of time, in exchange for payment. This is separate from the energy and capacity market programmes – indeed, a resource may not bid into the ICAP SCR if they participate in this programme.

The ICAP SCR program pays retail electricity customers to provide their load reduction capability for a specified contract period. Programme participants receive payments for an agreement to curtail usage during times when the electric grid could be jeopardized. Based upon system condition forecasts, participants are notified to curtail this subscribed “capacity,” either through the use of on-site generation and/ or reducing electricity consumption to a firm power level. Any under-performance results in an assessment of a penalty. To register for the program, participants commit to a load reduction of a minimum of 100 kW with 100 kW increments, subject to a one-hour verification either through an actual event or test to be called by NYISO.

Program providers offer 21-hour advance notice of any anticipated need for curtailment. A confirmation notice is provided a minimum of two hours before the actual event begins.

The participant’s metered load during the event hours is compared with the subscribed firm-power level, or the metered generator output is compared with its subscribed output level. Any under-performance of either load curtailment efforts, or generator output, will result in a reduction, or “derating” of any future capacity claims. Such a “derate” will require the customer to fulfil any contractual obligations entered into for capacity and will result in a proportional reduction of any future long-term contractual payments.

When initially registering for ICAP SCR, program providers calculate an unforced capacity obligation (UCAP) that is based upon a participant’s claimed load reduction capability, line losses, and historical program performance, if any exists. The UCAP is then sold into wholesale capacity markets where payment rates vary according to a participant’s location in the State and the contract period.

ICAP SCR resources are called before EDRP resources however if an ICAP SCR resource is not contracted in any month, then it can participate in the EDRP programme. ICAP-SCR resources are eligible for an energy payment at the minimum price guarantee, up to $500/MWh. The minimum price guarantee, or strike price, is specified by the ICAP-SCR resource and may be revised monthly.

A.5 NEW ENGLAND INDEPENDENT SYSTEM OPERATOR

A.5.1 History and Background

New England’s original capacity market was nearly identical to that of the NY-ISO. LSE’s were required to procure capacity to cover seasonal peak load, plus an additional reserve margin. Under the original market design, generators were being paid for idle units based on UCAP. ISO-NE’s original capacity market traded UCAP for the entire pool for monthly and deficiency auctions. Since the initiation of the auctions in April 2003, the NE-ISO capacity auctions cleared at less than $3/kW-month and many at zero. In 2005, weighted average prices were significantly lower than those for the NY-ISO at only $2.32/kW-year. NE-ISO however differed from the NY-ISO in that the NE-ISO did not have a locational aspect. As a result, price signals did not distinguish between areas that needed capacity and those that did not. It also had the effect of a serious mis-location of new generation, which naturally gravitated to areas with low construction costs and ready access to fuels (primarily natural gas)—precisely the remote locations poorly suited to serving load growth in coastal cities.

These deficiencies led the NE-ISO to adopt an entirely new capacity market design, the Forward Capacity Market ("FCM") on December 1, 2006. Under the new market, NE-ISO forecasts power system demand three years in advance and holds annual auction processes to purchase sufficient resources. The goal of FCM is to create a market structure that will not only support appropriate levels of existing capacity, but also encourage the much needed development of new generation in New England. In the sections that follow, we describe the FCM is greater breadth, analyze the performance of the NE-ISO market to date, and discuss short-comings and future reforms to the design.

A.5.2 Overview of Market Design

While the New England ISO ("NE-ISO") initially considered a new market design that simply incorporated the locational aspect, the idea was ultimately discarded and a different design was adopted: the FCM. New England's FCM is similar to the PJM's RPM market design in that it purchases only the quantity of capacity needed to meet the planning reserve margin and that it does so more than three years in advance of the planning year, thereby allowing planned resources to complete on a par with existing resources. There are however three key elements that set the FCM design apart from the RPM.

- First, the FCM does not rely on a demand curve but rather on the elasticity of competitive supply to produce reasonable prices. This is intended to enable the market price to reflect the actual competitive cost of capacity in the market at all times.
- Second, the capacity market represents both a physical and financial commitment. A resource cleared in the FCM is required to have the resource available in the day-ahead energy market. While this obligation can be transferred, only another qualified capacity resource can take on such an obligation. The capacity resource is also akin to selling a financial call option. This option has a strike price that is equal to the dispatch cost of a marginal resource and is struck against real time prices. Under the FCM, capacity obligation holders are responsible for payments under the option regardless of whether their resource was available for dispatch.
- Third, ISO-NE did not believe that that penalty associated with forced outages provided meaningful incentive for resources to be available when most needed. Therefore, under the FCM design, LSEs do not pay penalties for unit outages during normal system operations, but pay stiff penalties if the unit is unavailable when the system is short on capacity. Penalties can range from 10 percent of annual payments per day and 21 percent per month.[24]

The FCM establishes an auction-based market for capacity resources referred to as the Forward Capacity Auction ("FCA"), with NE-ISO procuring 100 percent of the forecasted capacity requirements for three years. Each LSE is required to pay for a share of capacity requirement proportionate to its share of peak load. While existing capacity can make commitments up to one year, new capacity may make a one-time commitment of up to five years during initial bidding. This incentive is meant to entice project financing in new capacity with predictable revenue streams during a project's first five years. In addition, the NE-ISO will also determine whether capacity zones are required before each auction. If such locational requirements are necessary, then separate and simultaneous auctions will be held for each zone. Capacity resources that may participate in the auction include (1) generating facilities, (2) intermittent resources, (3) demand response resources and (4) imports of capacity resources from outside NE-ISO.

24 Stoddard, Robert and Seabron, Adamson, "Comparing Capacity Market and Payment Designs for Ensuring Supply Adequacy," Charles River Associates Paper.

The auction process in the FCM is a descending clock auction, with the starting price set at two times cost of new entry ("CONE"). In this auction process, if the number of MWs offered is more than the number of MWs required at the end of the first round, prices will be lowered in the proceeding round. The process continues until the number of MWs offered equals the number of MWs demanded. The auction winners are those bidders in the last round that pay the capacity clearing prices. During each FCA, reconfiguration auctions also take place that provides a mechanism for NE-ISO, LSEs and generators to trade capacity obligations to maintain market liquidity. These configurations auctions include (1) three annual auctions before the commitment period, (2) monthly auctions held prior to each commitment month and (3) seasonal auctions held prior to June and October of each year to sell seasonal strip products.[25]

A.5.3 Performance of the Forward Capacity Market

The first FCA was held in February 2008 for the 2010-2011 planning year. By many regards, the FCM is considered successful in achieving its objective. At the time that the FCM was agreed upon, less than 1,000 MW of generation existed in the interconnection queue. Since the FCM however, more than 13,000 MW was added to the queue resulting in robust bidding in during the FCA. NE-ISO received offers for more than 39,155 MW of resources for an expected demand of 32,305 MW. The auction cleared more than 1,813 MW of new supply and demand side resources and added 1,188 MW of demand side resources to its existing base of 1,366 MW. These results imply that 10 percent of New England's peak load will be available for dispatch, the highest amount of committed load reduction on any U.S. system.

A.5.4 Role of Demand

Demand resources in the NE electricity market include Energy Efficiency, Load Management and Distributed Generation. The main criterion is that demand resources must result in additional and verifiable reductions in end-use demand on the electricity network.

There are five products defined in the NE market:

- Real-time demand response;
- Real-time emergency generation;
- Critical peak
- On Peak
- Seasonal Peak

On-peak resources provided their load reduction between 1-5pm on non-holiday weekdays in June, July and August and between 5-7pm on non-holiday weekdays in December and January.

Seasonal peak demand resources must reduce load during non-holiday weekdays when the real-time hourly load is equal to or great than 90 percent of he most recent 50/50 system peak load forecast for the applicable summer or winder season.

Real time resources (both demand and generation) receive dispatch instructions with 30 minute notice and must continue until they receive a notice to end. Emergency generators however are limited to emergency generators with permit restrictions.

25 Patrizia, Chuck and Scharfenberg, Bill, "New England Forward Capacity Market: A Strongly Supported Settlement With Long Run Risk," March 2006.

All project sponsors must both offer, and deliver, capacity in all 12 months of the year (including the seasonal peak category). For seasonal resources the rules allow a combination of demand and generation resources.

In addition to demand response in the capacity market, there is also the Real Time Price Response scheme in NE which operates in the energy market – giving incentive to customers if they reduce load at a time when prices exceed a trigger price.

A.6 CALIFORNIA INDEPENDENT SYSTEM OPERATOR

A.6.1 History and Background

The California Independent System Operator ("CAISO") began operations in 1998 and today controls over 80 percent of the state's total electrical load and serves more than 30 million people. Over 100 electric transmission and generation companies participate in CAISO, whose main objective is to allocate transmission space, maintain operating reserves and match supply and demand.[26] Over the last several years, California has designed and implemented a new Resource Adequacy ("RA") program and is currently evaluating whether a capacity market would be a beneficial complement to the phased-in RA program. This section seeks describe the RA program in brief and provides a discussion on the on-going debate on the adaptability of a capacity program.

A.6.2 Resource Adequacy Market Design Overview

Each year, the RA program requires LSEs to submit a series of filings including load forecast and compliance showings in September and October and twelve month-ahead filings. These forecasts, which are verified by the California Energy Commission ("CEC"), then serve as the foundation for each LSE's resource adequacy requirement. According to program rules, LSEs can submit monthly forecasts to the CEC to show any changes in load expected due to load migration. The CEC then checks the revised level to the state-wide forecast, then supplies each LSE with its adjusted monthly load forecast. During the final stage, the CEC makes adjustments to LSE based on several factors. First, the CEC adjusts for transmission losses and the IOU load for customers returning from direct access. Second, plausibility adjustments to account for customer retention, demand side management, and an adjustment to add load in aggregate to bring the total forecast to within one percent of the CEC's service area forecasts are made. Finally, aggregate service area forecasts are adjusted for coincidence.[27]

A.6.3 Debate on Capacity Programs

California currently has several large scale energy policy initiatives that contribute to the uncertainty about the need for long-term resource program like a capacity market system. These include the Market Redesign and Technology Update ("MRTU"), the uncertain future of retail choice, and an aggressive renewable energy and green house gas emission goals.

26 "The Role of California ISO," CAISO Company Information and Facts.

27 CAISO website.

A.6.4 Market Redesign and Technology Update

CAISO has recently implemented MRTU, which include many features such as day-ahead integrated forward market with LMP, a new local market power mitigation mechanism, obligation type congestion revenue rights and a residual unit commitment process. Under the MRTU market design, a generation unit owner that signs a fixed price forward contract that clears against the price at the counterparty retailer's location has significant incentive to run its generators and minimise price differences between retailer's location and the its dispatch price. Further, the short-term LMP enables retailers to sign RA contracts and fixed-price forward contracts for energy that hedge virtually all of the locational price risk faced by the retailer. Still under discussion in the MRTU is more granular pricing of ancillary services whose objective is to provide greater transparency to all parties about the benefits a specific generating unit provides to electricity consumers.

In fact, the 2008 Resource Adequacy Report has reported a significant level of success with the RA program. During that year, no outages or other significant reliability programs occurred within CAISO due to the availability of adequate generating resources. CAISO further reduced backstop procurement by a large margin by focusing on precise reliability needs in addition to a system energy perspective.[28]

A.6.5 Uncertainty in the Retail Market

In addition, a major uncertainty concerns retail choice, which is currently unavailable to most consumers in California. It is important to recognise that the existence and form of retail choice is an essential piece of information necessary to craft a satisfactory resource adequacy policy. Without choices, the rationale for a capacity markets system becomes minimal as the majority of load is served by a single jurisdictional entity. Even if choices do become readily available in the future, costs of existing and conditions of return are factors in determining the needs of and attributes associated with a long-term resource adequacy program. Until there is greater certainty in the liberalization of the retail market, it becomes very difficult to design a capacity market that is ultimately meant to better serve customers.

A.6.6 Renewable Energy Policy

Finally, California currently has a legislative mandate that investor-owned utilities and energy service providers satisfy 20 percent of their retail sales using renewable energy by 2010 and that energy agencies have established policies to increase this requirement to 33 percent by 2020. In addition there is a 10 year goal of 3,000MW of roof top solar photovoltaic installations. These goals in addition to a number of energy efficiency programs to begin between 2009 and 2011 are expected to reduce overall energy consumption and peak demand throughout the state. These supply-side renewable generating technology goals and demand-side efficiency programs imply less need for non-renewable generation through 2020 and that investment in generation be focused on renewables and energy efficiency.[29]

28 2008 California Resource Adequacy Report.

29 "Final Opinion on "Long-Term Resource Adequacy under MRTU," 5 November 2007.

A.7 SUMMARY OF US CAPACITY MARKETS

These various market implementations were not uniformly successful. As problems arose, market designs were altered and refined. As a result, the experiences in these various markets – particularly the tight-pool markets of the Northeast US – demonstrate both what works and what does not work. These experiences provide lessons that may be transferrable to other markets.

Freedom from stranded cost issues. The deregulation and restructuring of the electricity markets in the Northeast US occurred largely during the 1990s. A major part of these restructuring proceedings involved the development of explicit mechanisms to deal with stranded cost issues. As a result, the development of the capacity pricing mechanisms focused directly on the issues of short-term energy security and long-term resource adequacy. The one small exception involved the specification of the NY-ISO administered capacity pricing formula; the linear formula is partly a concession to generators who pleaded for additional revenues during the then-current period of excess capacity.

Capacity/energy interactions. Capacity and energy markets are linked. One view of capacity is that it represents an option to buy or produce energy at some price – for example, this definition is directly embodied in the NE-ISO forward capacity market (FCM). In its purest form, it simply provides the option to buy energy at the market price. This linkage between capacity and energy has several implications.

- Market power mitigation measures and energy price caps affect energy price levels over time. Since the combination of energy and capacity prices together must provide sufficient revenues to induce the retention of existing capacity and the development of new capacity, the capacity prices – as the residual revenue source – will reflect the specifics of these energy market rules.
- Because the capacity price is essentially a residual price derived from overall revenue requirements net of energy revenues, the capacity market can to some extent compensate for inadequacies in energy market pricing. In particular, locational capacity prices *could* provide the necessary investment signal to site resources in needed areas even if energy markets provide no such locational signal. But these US examples do not support this practice. All of these US markets implement locational energy pricing. While they also eventually moved to implement locational capacity pricing as well, the granularity of the capacity pricing is generally much less than that of the associated energy markets.

Locational pricing. The experiences of the tight pools in the Northeast US suggest that capacity should be priced at least to some extent on a locational basis.

- The experiences with the installed capacity (ICAP) market in PJM demonstrate that the failure to provide a clear locational definition for capacity resources can lead to destructive arbitrage and gaming – which were exacerbated in this case by the failure to assign clear rights to transmission capacity between PJM and surrounding markets.
- The original NE-ISO capacity market – which was not locational – resulted in the development of resources in remote locations, rather than close to the markets where they were needed. In theory, energy market price signals *should* have been able to prevent such mis-located development. But the timing of development and the impact of development on energy prices makes it difficult for observed energy prices to provide a sufficient signal. Prior to development, energy prices may be relatively uniform across the region. It is only *after* the mis-located development induces transmission congestion that prices across the region decouple and make evident the need to locate capacity close to the load centre.

- Transmission investment – via congestion effects – will have a strong impact on energy and capacity prices. In order to provide stable expectations for generation developers, transmission investment plans must be communicated well in advance. Conversely, generation investment – by inducing transmission – will create the need for incremental transmission. Thus, transmission planning must be coordinated with market operation.

Short-term capacity pricing. The theory of capacity markets suggests that an hourly or daily capacity price reflecting the scarcity value of capacity resources should be sufficient to induce proper investment. The US experiences suggest otherwise.

- Short-term pricing mechanisms are subject to manipulation and the abuse of oligopoly power. Short-term capacity prices reflect the current balance of supply and demand. Since short-term supply and demand is essentially inelastic, the unilateral act by any supplier to withhold capacity can cause the market-clearing capacity price to skyrocket – as demonstrated by the PJM ICAP experiences.
- These mechanisms produce extremely volatile prices, essentially bouncing between zero and whatever price cap exists. This is the natural consequence of the short-term gaming.
- Short-term pricing mechanisms fail to induce the development of new generation. The near-zero prices in the NE-ISO provided no incentive for development whatsoever. The brief periods of high ICAP prices in the PJM market reflected strategic bidding, rather than any underlying shortage. Accordingly, they provided no clear signal to investors. Moreover, the volatility of these prices created a very uncertain investment environment – one not at all conducive to development.
- The NY-ISO "administered pricing" mechanism bypasses some of these problems by tying capacity prices to reserve margin via an administered formula. Nonetheless, while the NY-ISO approach vastly reduced price volatility, it was not successful in attracting new investment.

Forward procurements. By contrast, the rolling forward procurements eventually implemented throughout the Northeast US markets appear to provide a much more stable and rational investment environment.

- Procurements years in advance allow competition between existing and new resources. Accordingly – as demonstrated in the NE-ISO FCM – it is possible to create a purely market-based auction mechanism that can yield relatively stable prices free of strategic manipulation.
- Since expectations of load and generation resource availability change over time, the initial procurement must be augmented by incremental auctions closer to the date of actual capacity delivery. It is less clear whether these incremental auctions will be able to avoid manipulation as well. Although the incremental volumes needed are much less, the shorter time frames limit the supply available to react. The ability of demand-side resources to bid into these auctions, however, does increase the supply elasticity.
- The existence of these forward obligations acts as a contractual hedge on any short-term market transactions. Accordingly, the incentive to manipulate short-term prices is vastly reduced. Moreover, the long-term instruments can be coupled with restrictions and obligations – as in the NE-ISO FCM – that help to ensure the availability of capacity on a short-term basis.

- The PJM and NE experiences suggest that forward procurements provide a superior platform for attracting generator investment. The existence of firm forward commitments for the initial years of operation – as well as the greater predictability of ongoing capacity prices – eases financing burdens. The existence of the forward procurements also provides clear signals as to what capacity is being developed. This information acts to mitigate the strategic gaming that occurs in many merchant markets.

Short-term availability. The potential gap between installed and available capacity creates the need for some mechanism to ensure adequate availability. The PJM ICAP mechanism tied prices to installed capacity, thereby creating the need to procure alternate capacity in the event of any outage. In conjunction with the overall market manipulation problems, this failed to ensure adequate availability. The NY-ISO market improved on this design by tying payments to unforced capacity (UCAP), based on a rolling average of forced outage rates. The NE-ISO FCM structure effectively creates obligations to ensure that resources cleared in the FCM are made available on a daily basis (or procured on an alternative basis). This obligation is backed by stiff penalties for unavailability during times of system shortage. Operation to date suggests that the FCM has been quite successful in providing short-term availability.

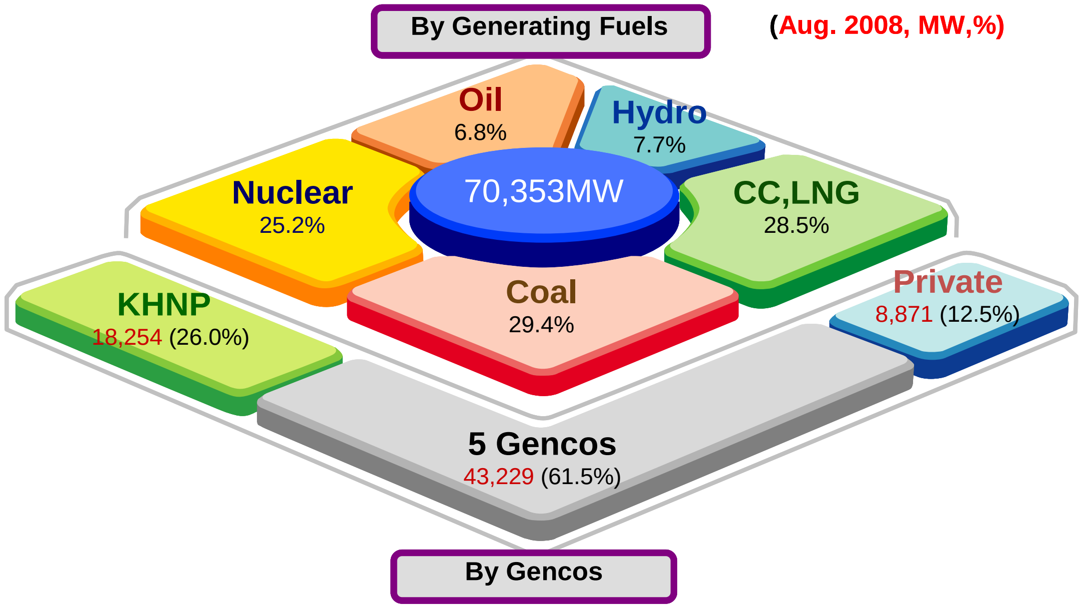
A.8 THE KOREAN ELECTRICITY MARKET

This section reviews the Korean capacity market, which is different from the US examples and then uses this review to identify some possible lessons for WA.

A.8.1 Physical system

South Korea is effectively an island system, having no inter-connection with North Korea. Over the last two decades, the system load has grown rapidly – averaging 9.7 percent annually from 1990-2000 and 6.4 percent annually from 2000-2007. Total peak demand (21 August 2007) was 62,285 MW. System resources totalled 70,353 MW as of June 2008. Accordingly, the system has a reserve market of about 13 percent, reflecting relatively tight market conditions. As shown by Figure, the generating capacity is quite diverse in terms of both fuel source and ownership. But Korea is heavily dependent on foreign energy resources, as 97 percent of its fuel use is imported.

Figure 3. Composition of Korean Generating Capacity



A.8.2 Electricity market operation

The Korean electricity market includes separate markets for energy and capacity. Table lists key features of market operation.

The energy market run by KPX is a day-ahead market. All generators are required to offer their available capacity into the cost-based pool. Bids are based on documented heat rate curves and accounting-based fuel costs (on a lagged basis), including adjustments for start-up and no-load costs, but ignoring variable O&M costs. The determination of the schedule is done essentially via an unconstrained dispatch, ignoring reserves requirements and transmission constraints.[30] Transmission losses are incorporated via the use of "marginal loss factors" that account for expected marginal losses from each generator to the weighted-average load centre. The system marginal price (SMP) in each hour is set by the highest dispatch price (including all adjustments) for any generator operating in that hour.[31] This unconstrained dispatch effectively determines the financial outcome for each generator in each hour.

The actual dispatch is effected via a real-time, constrained dispatch that incorporates reserves and transmission constraints. Schedule differences between the day-ahead, unconstrained dispatch and the real-time, constrained dispatch are managed via constrained-on (CON) and constrained-off (COFF) orders. The associated CON and COFF payments to generators have the effect of ensuring that each generator's profits for the actual dispatch match the forecast profits for the day-ahead dispatch.

30 The intention is to move toward a zonal model that would reflect transmission constraints and thereby provide improved pricing signals. Currently, the island of Cheju has been split off as a separate zone, so the "unconstrained" dispatch is now being tested as a two-zone system.

31 This determination, however, excludes generators forced to run at minimum load at night. Accordingly, the SMP at night may be lower than the cost-based bids of some of the generators.

Table 3: Key Features of Korean Market Operation

Market Features		
Market	**Product**	**Capacity Market**
- Day-ahead market only - No forward market - No real-time market - No price bidding, only capacity bidding	- No reserve market - Hourly SMP from unconstrained dispatch - Until 2006, BLMP was used for base load plant	- Administratively determined capacity payments (CP) - Until 2006, capacity payment (CP) for base load > CP for peak
Generation Costs		
Cost Curve	**Fuel Cost**	**Bidding**
'- Generation cost curve is a quadratic function. - The co-efficient of cost curve is tested periodically and approved by The Committee	'- Genco reports fuel cost to KPX based on purchasing cost -Generally, there is two months delay on fuel cost calculation	- Genco reports hourly available capacity of generator. - KPX performs generation scheduling with a cost curve incorporating fuel cost and available capacity, together
Day Ahead Market		
- KPX set two Generation schedules: constrained (determines real operation) and unconstrained dispatch (determines market price) - constrained on/off is used for settlement.	- No price bidding for capacity. Gencos offer their available capacities.	

The capacity pricing is determined administratively and applied on an hourly time-of-use basis. The total annual capacity payment is set so as to recover the fixed cost of a hypothetical peak load GT generator assumed to be in Ulsan, far from the Seoul load centre. The hourly variation in capacity payments is relatively small, however; thus, there appears to be no intent to reflect the true scarcity value of capacity on an hourly basis. Prior to 2006, both the energy and capacity markets were bifurcated, with separate prices for base-load and other generators. This separation was abolished in 2006.

Agenda Item 4(b): Recommendations from the 2011 Annual Wholesale Electricity Market Report for the Minister for Energy

The Economic Regulation Authority (ERA) on 5 April 2012 published its annual report on the effectiveness of the Wholesale Electricity Market in meeting the Wholesale Market Objectives. Contained within the report are a number of recommendations relating to the matters currently before the Reserve Capacity Mechanism Working Group for consideration. A copy of the report has been provided as an appendix to this paper. Further details of the recommendations are reflected below:

<table>
<tr><th>Recommendation</th><th>Details</th></tr>
<tr><td rowspan="3">Recommendation 1

Section 2.3

(Pg 21)</td><td>The treatment of Demand Side Management in the Wholesale Electricity Market should be reviewed by the Reserve Capacity Mechanism Working Group.</td></tr>
<tr><td>Given the materiality of this review, and reflecting the Authority’s recommendations on the Rule Change Process, the Authority recommends that the Public Utilities Office should be involved in the working group and ensure that the outcomes of the working group are consistent with broader energy market policy.</td></tr>
<tr><td>The working group’s consideration of the treatment of Demand Side Management should consider the merits of models adopted in other jurisdictions, including the option of changing the payment received by Demand Side Management to reflect the value provided by Demand Side Management.</td></tr>
<tr><td rowspan="2">Recommendation 2

Section 2.4

(Pg 25)</td><td>The incentives for plant availability created by the inter-relationship between the Reserve Capacity Mechanism and Reserve Capacity Refund payments should be reviewed by the Reserve Capacity Mechanism Working Group.</td></tr>
<tr><td>Specifically, the working group should consider whether the design of the Reserve Capacity Mechanism provides appropriate incentives for plant availability and whether a refund regime that links refund payments to system conditions would improve incentives for availability.</td></tr>
</table>

The IMO recommends that the Working Group notes these recommendations

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EXECUTIVE SUMMARY

The Wholesale Electricity Market (**WEM**) has been established in the South West Interconnected System (**SWIS**) as part of the State Government's reform to deregulate the electricity industry in Western Australia. The main objective of this market is to facilitate greater competition and encourage private investment in the generation and retail sectors, and ultimately to minimise the cost of electricity supplied to consumers.

A key element of the WEM is the Short Term Energy Market (**STEM**), which enables market participants to adjust their contract positions prior to each trading day. Real-time deviations from contract positions are settled with the Independent Market Operator (**IMO**) through the balancing mechanism. This market design was based on the expectation that retailers would cover most of their electricity requirements through bilateral arrangements with generators, outside of the formal WEM processes.

The market also includes a mechanism for ensuring that adequate generation and Demand Side Management (**DSM**) capacity is available to maintain reliability and security of electricity supply. This is referred to as the Reserve Capacity Mechanism (**RCM**), which is a significant feature of the WEM design.

The WEM plays an important role in keeping downward pressure on electricity prices. It ensures the least cost portfolio of generation is established, resulting in lower wholesale energy costs. These wholesale energy costs comprise around 40 per cent of the electricity bill for an average residential customer, so lower wholesale energy costs will have a material impact on electricity bills. The WEM achieves the least cost portfolio of generation by promoting competition between generators in two markets: the energy market (where buyers and sellers can trade electricity through bilateral contracts, the STEM, or through the balancing mechanism); and the capacity market where electricity retailers are required to purchase capacity, either bilaterally or from the IMO.

Outcomes in the WEM over the five and a half years since market commencement indicate that the market functions well, to the benefit of electricity consumers. The volume of trading in the STEM is at its highest level since market commencement and average STEM prices are at their lowest levels. The price for capacity has fluctuated over time, but has recently been reduced by one third. There has also been greater competition in the market, particularly in the generation sector. The Authority is encouraged to note that Independent Power Producers (**IPP**) will account for 49 per cent of certified capacity in 2013/14, up from 11 per cent in 2005/06, when the market commenced. Over $2 billion worth of private funds have been invested in electricity generation in the SWIS. These are good outcomes for electricity consumers and taxpayers in Western Australia.

Like electricity markets globally, it was always expected that the WEM would need to evolve. The Authority is aware of the current work program of activities, largely undertaken by the IMO, with regard to the introduction of competition for the provision of the balancing and load following ancillary service. To date, Verve Energy has been the sole provider of these services. The implementation of the competitive balancing and load following ancillary service market, expected to take effect on 1 July 2012, will allow IPPs to compete with Verve Energy for the provision of these services, which will set the next stage in the development of the market.

Notwithstanding the above, there are a number of issues regarding the WEM's operation that require resolution. These include:

- the potential merger between Verve Energy and Synergy, which will further expand structural barriers to effective competition and increase cost pressures on consumers;
- the substantial excess capacity procured under the RCM;
- the increasing costs to the market of DSM;
- the effectiveness of the outage planning process, in particular, the high rates of planned outages allowed for certain generation facilities and the associated impact on market prices;
- the impact of increasing intermittent generation as a result of climate change policies; and
- the potential for a conflict of interest under the current market governance arrangements.

These issues are discussed in more detail below.

Key issues affecting the WEM

Potential merger between Verve Energy and Synergy

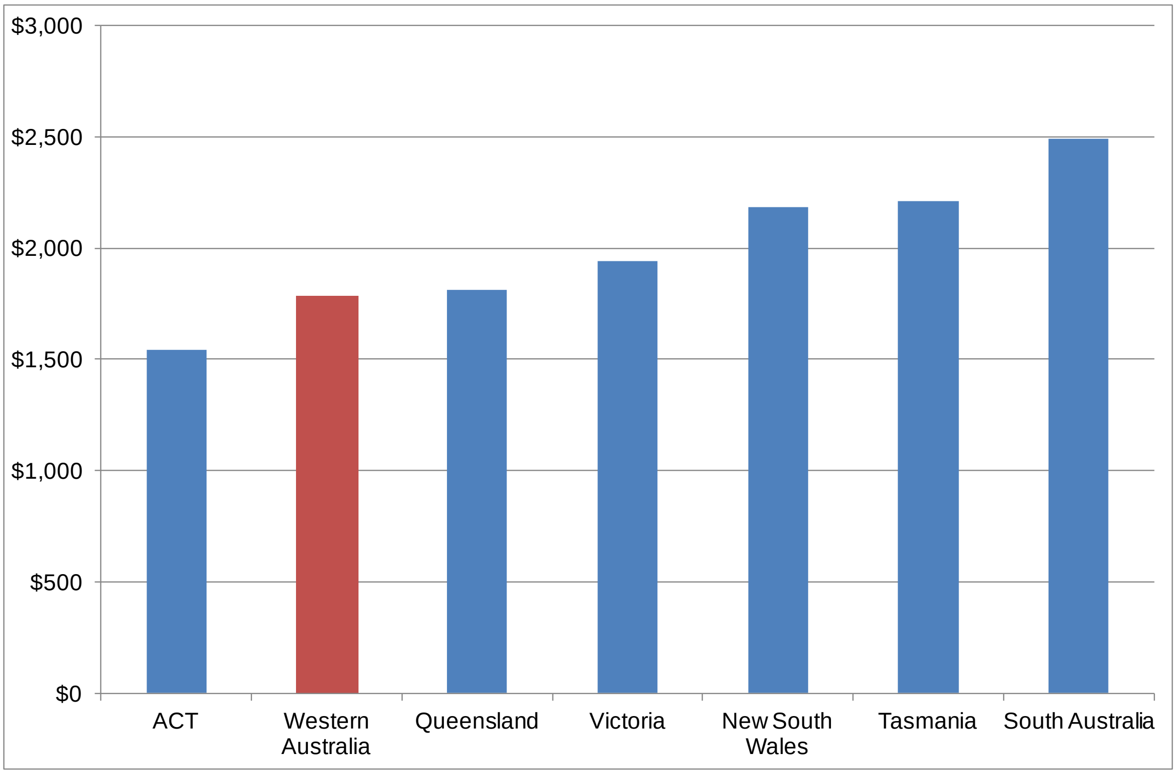
The continuing domination of the market by Verve Energy and Synergy is of ongoing concern to the Authority because of the importance of competition to the effectiveness of the WEM. Additionally, the Authority notes that there is increasing concern among Market Participants that the process of extending competition in the market may not continue. In particular Market Participants are concerned about the proposed merger of Verve Energy and Synergy. A merger between Verve Energy, the largest generator in the market, and Synergy, the largest retailer in the market, would be detrimental to consumers because it would likely discourage future private investment, reduce competitive tension, reduce transparency, and increase the need for regulatory oversight. This would ultimately be to the detriment of electricity customers. Consumers are served better by competition than by regulation.

Tariff increases

One suggestion amongst proponents of a merger between Verve Energy and Synergy is that their initial separation through the disaggregation of the old Western Power Corporation contributed to the recent 57 per cent increase in residential electricity tariffs. However, it is the Authority's view that this increase in electricity tariffs was inevitable, regardless of how the disaggregation of the old Western Power Corporation was structured (i.e., regardless of whether Verve Energy and Synergy remained as one, or separate, government trading entities). The increases in residential retail tariffs commencing from April 2009 followed twelve years of constant electricity tariffs (meaning that tariffs had not even kept pace with inflation since 1997/98)[1]. Even after the 57 per cent increase, the current residential tariff in Western Australia still ranks low amongst Australian jurisdictions.

[1] Government of Western Australia Office of Energy, *Electricity Retail Market Review*, Final Recommendations Report, January 2009.

Estimated annual electricity cost in Australian jurisdictions as at August 2011[2]



The tariff increases in recent years were largely the result of:

- increases in Western Power's network prices, following a period of substantial underinvestment in the network, to ensure that the network is operating appropriately;
- significant increases in the subsidy to Horizon Power through the Tariff Equalisation Contribution, to facilitate the State Government's policy of having uniform electricity tariffs across Western Australia for regulated customers;[3]
- higher fuel costs, particularly given the lack of gas on gas competition to supply the domestic market and the high price of LNG; and
- increases in the costs to retailers of complying with the Commonwealth Government's renewable energy policies.

[2] Estimated costs are based on a customer using 7,500 kWh of electricity per year. WA cost is calculated based on the A1 tariff charges (as effective from 1 July 2011) of: a supply charge at 40.14 cents per day; and an electricity usage charge of 21.87 cents per kWh. Costs for the National Energy Market jurisdictions are sourced from the ACCC's 'State of the energy market 2011' report, p. 114. See the ACCC website, *State of the energy market 2011 web page*, http://www.accc.gov.au/content/index.phtml/itemId/1021485. In the case where the ACCC's report cited multiple cost values for NEM jurisdictions, the average of these values is shown.

[3] Under the State Government's uniform tariff policy, regional WA customers outside the SWIS pay the same tariffs for their electricity as customers in the SWIS. The uniform tariffs are the same even though the costs to provide electricity to regional customers are higher than those in the SWIS. The difference between the cost to supply electricity and the revenue collected from Horizon Power customers is subsidised by the State Government in two ways. The first is in the form of Community Service Obligations (**CSOs**), which are funded through general taxation. CSOs can cover the funding of specific projects or programmes. The second is the Tariff Equalisation Contribution (**TEC**), which is funded by an additional charge to customers on regulated tariffs, collected by Western Power as part of the distribution network tariffs. This charge is paid into the Tariff Equalisation Fund, which ultimately funds the TEC.

Had Verve Energy and Synergy still been amalgamated over this time, there would not have been a discernible impact on the need for increased electricity tariffs. Indeed, the reduced competition in the WEM may have resulted in higher wholesale energy prices and higher costs to electricity customers.

The Authority's recently released draft report on the Inquiry into the Efficiency of Synergy's Costs and Electricity Tariffs has indicated that the pressure for further tariff increases will moderate although there is still some cost catch-up required to achieve cost reflectivity. The Authority has estimated that the regulated tariffs, averaged across all customer groups, would need to increase by 15.8 per cent (including 8.2 per cent for the introduction of the carbon tax) in 2012/13 to ensure that taxpayers are not covering the gap between efficient cost and revenue earned by Synergy. Given that network charges make up approximately one third of total electricity costs, the Authority's estimate has taken into account the Authority's draft decision on Western Power's third access arrangement[4], which has indicated that network costs should not be adding any pressure to retail electricity tariffs in the next five years from 1 July 2012 to 30 June 2017.

Verve Energy's plants sitting idle overnight

Another of the stated reasons in support of a merger between Verve Energy and Synergy is that the operation of the market, in its current form, has resulted in Verve Energy's plants sitting idle overnight. However, there are two key factors responsible for this situation i.e., the excess base-load generation capacity in the market and the increases in wind generation.

Since market commencement, three base-load generation facilities have been commissioned into the WEM:

- NewGen's Kwinana gas-fired generation facility (320 MW), commissioned in 2008/09, was underwritten by the old Western Power as part of its power procurement program.
- Griffin Power's first coal-fired unit at the Bluewaters Power Station (240 MW), also commissioned in 2008/09, was driven by a major mining investment in the local area under a commercial arrangement between Griffin Power and Boddington Gold Mine.
- Griffin Power's second coal-fired unit at the Bluewaters Power Station (240 MW) was commissioned in 2009/10. The development of this unit was brought to the market by Synergy's procurement process as required by the Displacement Mechanism under the original Vesting Contract. Verve Energy participated in this competitive tender process but was unsuccessful.

It was the commissioning of the latter i.e., Griffin Power's second unit at the Bluewaters Power Station, that was seen as having created excess base-load capacity in the market. This, however, has also brought cheaper energy to the market, with the ultimate benefit to consumers, as Synergy was able to procure electricity supply from Griffin Power at lower prices than offered by Verve Energy. Other Market Participants have also benefited from the lower energy price as a result of the commissioning of Griffin Power's second unit, as is indicated by the lower STEM and balancing prices observed in the market.

Over the past five and a half years, close to 400 MW of wind generation has been installed in the SWIS. One of the challenges brought by these wind generation facilities is that they are intermittent and often produce at high output levels overnight, when system demand is

[4] Network charges make up approximately 40% of the total electricity costs for residential customers. The Authority's draft decision sets a cap of $6.8 billion on the revenue Western Power can earn over the next five years.

low. To promote the development of wind generation, to date, these wind generation facilities have been able to operate in preference to base-load generation capacity. As a result, there has been strong competition amongst base-load generation plants to supply overnight when system demand is low, which has resulted in some occurrences of negative prices in the WEM. Furthermore, Verve Energy's facilities have been the first to be turned-down when required, as Verve Energy is currently the default provider of balancing services (an arrangement made at the commencement of the WEM).

The Authority's view is that a merger between Verve Energy and Synergy would not avoid the situation of Verve Energy's plants sitting idle overnight. Rather, the current excess base-load generation will eventually be resolved by load growth. Furthermore, the introduction of a competitive Balancing market from July 2012 is intended to provide an opportunity for both Verve Energy and IPP's to supply balancing services to the market on a competitive basis, resulting in the more efficient use of available generators.

Market dominance and structural barriers to effective competition

Another of the stated reasons in support a merger between the two organisations is that it would produce higher combined profits. It is suggested that, at present, Verve Energy and Synergy, while both Government-owned, have competing objectives, thus resulting in lower combined profits. However, it is the Authority's view that merging Verve Energy and Synergy would only result in higher combined profits as a result of a reduction in competition, and therefore, higher prices for consumers.

The Authority is concerned that a merged Verve Energy and Synergy would be able to impede its competitors' access to commercial opportunities in the electricity market. For instance, the retail arm of the merged entity may favour the generation arm over competing generators when it comes to contracting for electricity supply. Similarly, the generation arm of the merged entity may favour the retail arm when it comes to contracting. The likely result would be to make it more difficult for competing generators and retailers to secure contracts on competitive terms. Given the importance of securing bilateral contracts for both independent generators and retailers in the WEM, this would affect the commercial returns of those competing generators and retailers that have already invested in the market and also would be likely to deter entry by new generators and retailers. This situation would require ring-fencing and monitoring arrangements to be put in place but this would be difficult to enforce and far less transparent compared to a market based outcome.

Importantly, the Authority's concern about the effects of a merger between Verve Energy and Synergy does not reflect a more general concern about all vertical integration between generators and retailers in the WEM. Rather, it is based on the particularly large market shares of Verve Energy in the generation sector and Synergy in the retail sector. Furthermore, The Authority notes that there are currently structural barriers to effective competition, including the absence of a clear framework for reducing the dominance of Verve Energy and Synergy in the market. Given the Authority's view that the gap between the current tariff level and the efficient cost reflective level is closing, the Authority considers it is now timely to introduce a strategy for achieving greater retail competition. An increase in retail contestability is not only important for consumer choice; it also underpins the effective functioning of the WEM by increasing the pressure on efficient electricity procurement and dispatch, and as such, is expected to lower costs to consumers.

Substantial excess capacity procured under the Reserve Capacity Mechanism

The RCM has been successful in securing sufficient capacity to meet forecast requirements in every Capacity Year since its inception. However, there has also been a material excess of capacity assigned to participants during this period. The excess ranged from as low as two per cent (or 113 MW) in the 2010/11 Capacity Year to a high of around 15 per cent (or 775 MW) in the 2013/14 Capacity Year.

The issue of the cost of the excess capacity secured under the RCM to the market has been a concern raised by market participants, as the excess capacity results in additional costs to the market, which is ultimately borne by consumers. The Authority notes that there is currently a mechanism that reduces the administrative Reserve Capacity Price (**RCP**) in proportion to the excess capacity when no market auction is held. However, the adjustment is not sufficient to nullify the impact on consumers of the excess capacity in the market.

Demand Side Management

Over recent Reserve Capacity Cycles there has been a significant increase in the number of Capacity Credits assigned to DSM by the IMO, from 131 MW (or 3.2 per cent of the total certified capacity) in the 2007/08 Capacity Year to 500 MW in the 2013/14 Capacity Year (or 8 per cent of the total certified capacity). Given that DSM is able to receive the same payments for providing capacity as are generators, this has resulted in significant increases in the payments to DSM providers. The implied cost of Capacity Credits provided by DSM will have increased to $89 million in 2013/14 from approximately $17 million in 2007/08.

While DSM providers are able to receive the same payments for providing capacity as are generators, DSM providers are not subject to the same obligations as generators with regard to availability levels. The Authority notes that currently most of the DSM providers only offer to be available for 24 hours during a year. There is also a limit on the number of consecutive hours and consecutive days during which DSM can be called upon.

Given the increasing cost to the market of DSM, the Authority notes that it is appropriate to consider whether the benefits currently provided by DSM justify the costs. The Authority recommends that alternative models should be considered to achieve a greater alignment between the payment received by providers of DSM and the value provided by DSM. This is discussed in more detail in Section 2.3.

Outage planning process

Planned Outages are outages of a generation facility (typically for maintenance work) that are approved by System Management. Once a Planned Outage is approved, a generation facility will not be subject to any reductions in the capacity payments it receives during that scheduled outage.

System Management makes decisions about whether to approve requests for Planned Outages on the basis of considerations of system security. However, Planned Outages can also have broader effects on the market, including price outcomes. The Authority's monitoring of the market has revealed a number of instances in which price spikes have coincided with Planned Outages.

The Authority has noted a number of generation facilities with extremely high rates of Planned Outages, in particular at Verve Energy's facilities. For example, the recorded Planned Outage rates at certain Verve Energy facilities during the 2010/11 Capacity Year were as follows:

- 53.6 per cent at the Kwinana G5 facility (174 MW);
- 49.6 per cent at the Kwinana G6 facility (174 MW);
- 49.3 per cent at the Pinjar GT11 facility (105 MW); and
- 42.7 per cent at the Muja G7 facility (211 MW).

These facilities received full capacity payments whilst they were unavailable for extended periods on Planned Outage. The Authority is concerned that these high rates of Planned Outages may indicate an issue with the incentives for plant availability provided by the market, leading to negative consequences for price outcomes in the market. In an effective market, the Authority would expect that generators would be provided with strong incentives to make themselves available to participate in the market, particularly at times of high demand to ensure that demand is met at a lower cost.

The Authority notes that there is a provision for monitoring Planned Outages under the RCM. As part of the Reserve Capacity Performance Monitoring requirements, the IMO must require Market Participants with a facility that has been unavailable due to Planned Outages for more than 1,000 hours (equivalent to 42 days or 12 per cent of a year) during the preceding 12 calendar months, to provide a report explaining these Planned Outages and setting out the expected maximum number of Planned Outages for the facility in the next 24 months. However, the Authority notes that these provisions are only triggered in circumstances in which SWIS-wide available capacity drops below a certain threshold level (i.e., 80 per cent during Hot Season and 70 per cent in either the Intermediate Season or Cold Season) for at least 40 days in any 12 month period. To date, there have been instances where the system availability threshold has been reached, however, the number of days were not as high as 40 over a 12 month period. Thus, the requirement for Market Participants with excessive Planned Outages to provide an explanatory report has not been triggered i.e., despite the poor availability of specific facilities. The Authority considers that the threshold for the IMO's monitoring of individual facility's availability level could be set too high and that this issue should be examined more fully.

As discussed in Section 2.4, the Authority considers that there may be options to improve incentives for plant availability, such as the amendment of refund payments so that they are higher if capacity is scarce at the time of an outage. This could increase the incentive for availability at times when it is more highly valued.

Effect of increasing intermittent generation

The Authority is aware that the increase in intermittent generation in the WEM, which is largely driven by the renewable energy policies, is giving rise to a number of issues for the market. These issues include the impact on the economic dispatch of base-load generation at low demand period (particularly overnight), the use of low efficient gas turbines to maintain frequency control, and the associated costs to the market. These issues have been the subject of ongoing reviews in the WEM.

The Authority considers that the introduction of a competitive Balancing market from July 2012 should deliver better outcomes with regard to the economically efficient dispatch of generation facilities, as both Verve Energy and IPPs will be able to compete for the provision of the Balancing service, particularly during low demand periods. In relation to the increased use of low efficiency gas turbines and the increasing costs of LFAS, the new competitive LFAS market from July 2012 should also contribute towards more efficient outcomes.

There are also cost pressures emerging as a result of the requirement on Western Power to provide newly connected generators with full, unconstrained access to the network. In last year's Report to the Minister the Authority concluded that an alternative approach that allows Western Power to accommodate new generation in a constrained manner, without making significant augmentation to the network, will lead to more efficient investment in the future. The Authority continues to support consideration of a move towards constrained network access.

Market governance arrangements

At present, the IMO is responsible for the rule change process. This creates the potential for a conflict of interest because the IMO is subject to the *Wholesale Electricity Market Rules* (**Market Rules**), while at the same time being responsible for making decisions about changes to the Market Rules. While there are processes in place to manage this potential for conflict, it is clear that Market Participants are increasingly concerned about the IMO's dual role. A number of Market Participants have suggested that the governance model in the National Electricity Market, in which there is an independent body responsible for the rule change process, would be preferable. While this is one potential model, the Authority is also aware that there are a range of different governance models in use in electricity markets around the world. These are discussed in Section 2.6. Given the increasing concern about governance arrangements among Market Participants, the Authority considers that it is timely for a review of governance arrangements and that this review should be undertaken by the Public Utilities Office, with input from all stakeholders.

Overview of outcomes in the WEM

Despite the issues facing the electricity market, the evidence is that the market continues to function well, and remains adequate for its purpose. The market outcomes observed by the Authority, and summarised below, remain generally encouraging.

The Reserve Capacity Mechanism

The Authority notes that the RCM has been successful in securing sufficient capacity to meet forecast requirements, with the number of Capacity Credits assigned to participants exceeding the Reserve Capacity Requirement (**RCR**) in each Capacity Year. The RCR is set by the IMO based on a peak demand forecast at 10 per cent probability of exceedance level plus a reserve margin (equal to the greater of 8.2 per cent of the peak demand forecast and the maximum capacity of the largest generating unit, measured at 41^{o}C, as required by the Planning Criterion in the Market Rules).[5]

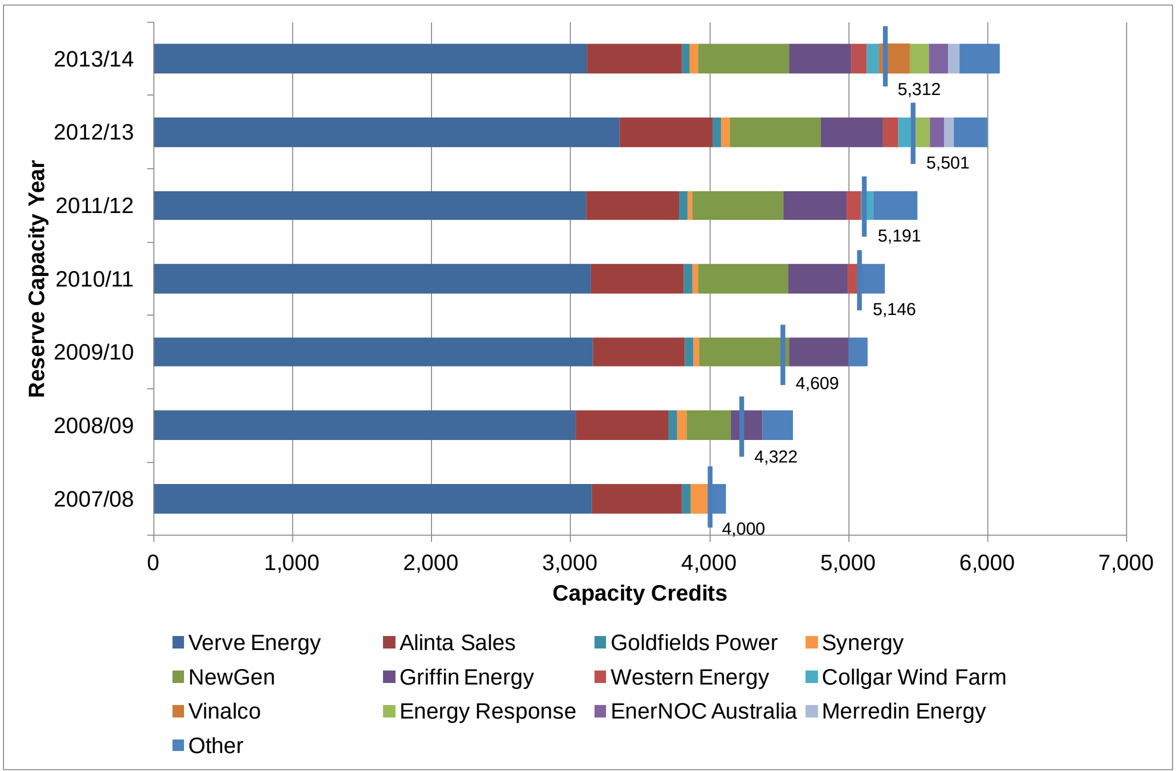
The figure below shows the Capacity Credits[6] assigned to Market Participants for the 2007/08 to the 2013/14 Capacity Years, as well as the RCR for those years (represented in the figure by the vertical dashes).

[5] Clause 4.5.9 of the Market Rules requires the IMO to set a Reserve Capacity Target for each Reserve Capacity Year at a level which ensures that the two elements of the Planning Criterion are met. The first element relates to meeting the highest maximum demand in that year. The second element ensures that adequate levels of energy can be supplied throughout the year.

[6] A Capacity Credit is a notional unit of capacity that can be traded between Market Participants. One Capacity Credit equals one megawatt of capacity. Capacity Credits are valid for a particular Reserve Capacity Year and are allocated by the IMO to specific generating plant or DSM facility.

The figure also shows the composition of the participants in the market. The Authority notes that the number of participants has more than doubled since market commencement, increasing from 4 to 12 participants. This is a good indication of increasing competition for the provision of capacity.

Capacity Credits assigned to Market Participants for the 2007/08 to 2013/14 Capacity Years



Note: In the figure above, the vertical dashes with the corresponding value represent the Reserve Capacity Requirement in each Capacity Year.

It can be seen from this chart that the number of Capacity Credits assigned to participants (in aggregate) has exceeded the RCR in each of the Reserve Capacity Years since 2007/08. The excess of Capacity Credits assigned to participants has ranged from a low of around two per cent (in the 2010/11 Capacity Year) to a high of approximately 15 per cent (in the 2013/14 Capacity Year), with an average over the seven years of 7.5 per cent (see the table below).

Excess Capacity Credits assigned to Market Participants and Capacity Credits provided by DSM for the 2007/08 to 2013/14 Capacity Years

Period	Reserve Capacity Requirement	Certified Reserve Capacity	Excess Capacity Credits	Excess Capacity Credits (%)	Capacity Credits provided by DSM
01/10/07 to 01/10/08	4,000	4,115	115	2.9%	131
01/10/08 to 01/10/09	4,322	4,600	278	6.4%	128
01/10/09 to 01/10/10	4,609	5,136	527	11.4%	99
01/10/10 to 01/10/11	5,146	5,259	113	2.2%	154
01/10/11 to 01/10/12	5,191	5,493	302	5.8%	260
01/10/12 to 01/10/13	5,501	5,996	495	9.0%	454
01/10/13 to 01/10/14	5,312	6,087	775	14.6%	500
Average			**372**	**7.5%**	

Some stakeholders have commented that the excess capacity that has been secured in each Capacity Year results in an additional cost to the market, which is ultimately borne by consumers. As indicated above, there is currently a mechanism in the Market Rules that takes into account excess capacity in the calculation of the Reserve Capacity Price (**RCP**). When excess capacity is secured, the RCP is reduced in proportion to the excess capacity. This mechanism is not perfect, however, because the reduction in the RCP will not necessarily be matched by a reduction in the capacity price that is bilaterally negotiated between buyers and sellers of capacity. These aspects of the RCM are discussed in more detail in Section 2.2.

The Authority notes that positive market outcomes have flowed, at least in part, from the RCM:

- a significant increase in Capacity Credits that have been assigned to new entrants, where the share of capacity provided by IPP's has grown from approximately 11 per cent in 2005/06 to approximately 49 per cent in 2013/14; and
- there have been no reported instances of curtailment of electricity supply due to capacity shortages since the commencement of the RCM.

However, whilst there are no instances of reported curtailment of electricity supply due to capacity shortages, the Authority notes that this comes at a significant cost to customers.

The retail market

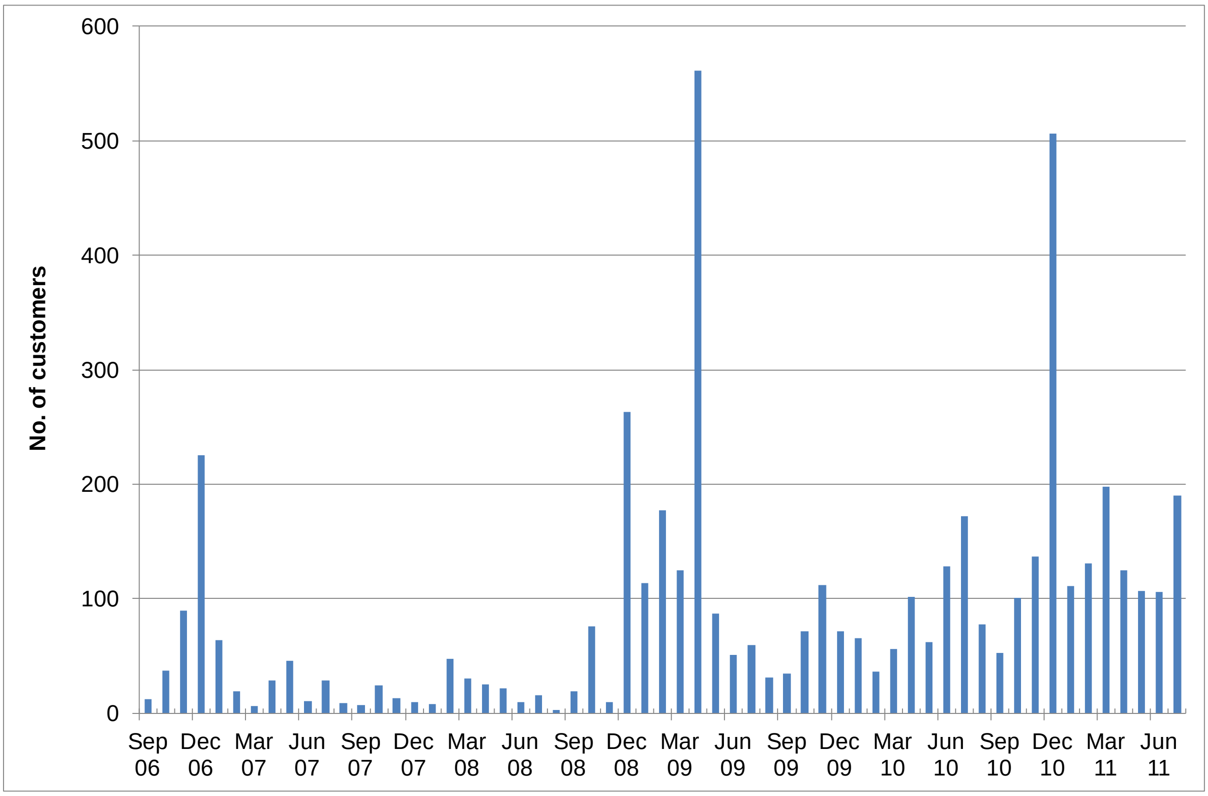
Alongside the increased competition for Verve Energy in the generation sector, there are signs that Synergy is facing increased competition in the retail sector. While retail contestability has only been introduced for customers that consume more than 50 MWh per annum (i.e., approximately 26,000 customers in the SWIS in the 2010/11 financial year), there are signs that a number of these customers are exercising their ability to choose their retailer.

The figure below illustrates levels of customer transfer in the contestable section of the electricity market, since market commencement. Levels of customer transfer spiked in the first few months following market commencement, with 225 customers being transferred between retailers in December 2006. Customer transfer numbers then moderated and remained relatively low throughout 2007 and the majority of 2008. The general trend has been toward a steady increase in the number of customers changing retailers since December 2008, which likely reflects the Government's decision to increase tariffs in 2009.

Notably, customer transfer numbers spiked in April 2009 (561 customers) and again in December 2010 (506 customers).

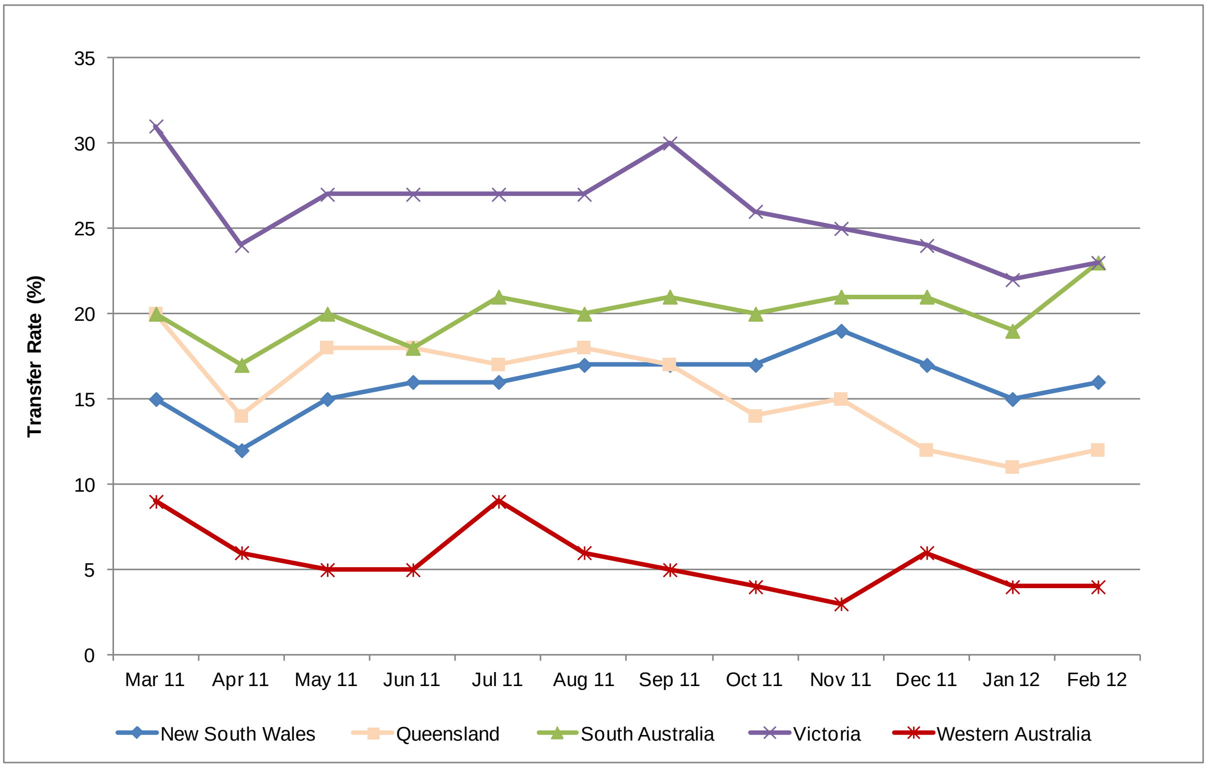
Despite these increases, the number of customers changing retailers each month (which has typically been between 100 and 200 customers over recent months) remains relatively small compared to the total number of contestable electricity customers. During the 2010/11 financial year, the average customer churn rate was approximately 0.6 per cent. The maximum and minimum monthly churn rates were approximately 2 per cent and 0.2 per cent, respectively.

Number of customers changing retailer (customers per month)



The following graph provides the one month annualised transfer rates published by the Australian Energy Market Operator, as well as the estimated rates for Western Australia, for the period March 2011 to February 2011. Notably, Western Australia's transfer rates are markedly lower than those observed in other jurisdictions, where there is full retail contestability.

1 month annualised transfer rates in Australian jurisdictions (for the period March 2011 to February 2012)[7]



Bilateral trade

Alongside the increase in the Capacity Credits assigned to IPPs and the increase in rates at which customers have been switching retailers, the Authority notes that there has been an increase in quantities traded bilaterally between IPPs and independent retailers:

- energy traded between Verve Energy and independent retailers has averaged 95 MWh per Trading Interval i.e., an increase of 32 per cent in comparison to an average of 72 MWh per Trading Interval between August 2009 and July 2010;
- energy traded between IPPs and Synergy has averaged 221 MWh per Trading Interval i.e., an increase of 31 per cent in comparison to an average of 169 MWh per Trading Interval between August 2009 and July 2010; and
- energy traded between IPPs and independent retailers has averaged 186 MWh per Trading Interval i.e., an increase of 133 per cent in comparison to an average of 80 MWh per Trading Interval between August 2009 and July 2010.

Given that the energy market is dominated by bilateral trades, the Authority expects that this increased activity in bilateral trades should lead to more competition and more efficient outcomes in the market.

[7] The 1 month annualised transfer rates are calculated by projecting the small consumer (i.e., annual consumption less than 160MWh for all jurisdictions except Queensland, which is less than 100MWh) transfer volume for that month over a 12 month period, and calculating the percentage churn that would occur if the transfer rate was maintained over the year. This value is then rounded to the nearest percentage. See the AEMO website http://www.aemo.com.au/data/retail_transfers.html. The Western Australian transfer rates are calculated based on the assumption that the total number of customers in the SWIS is 26,000 over the period represented in the figure.

Short Term Energy Market

Overall, the Authority considers that, while the STEM has certain limitations, it is fulfilling its function in the WEM.

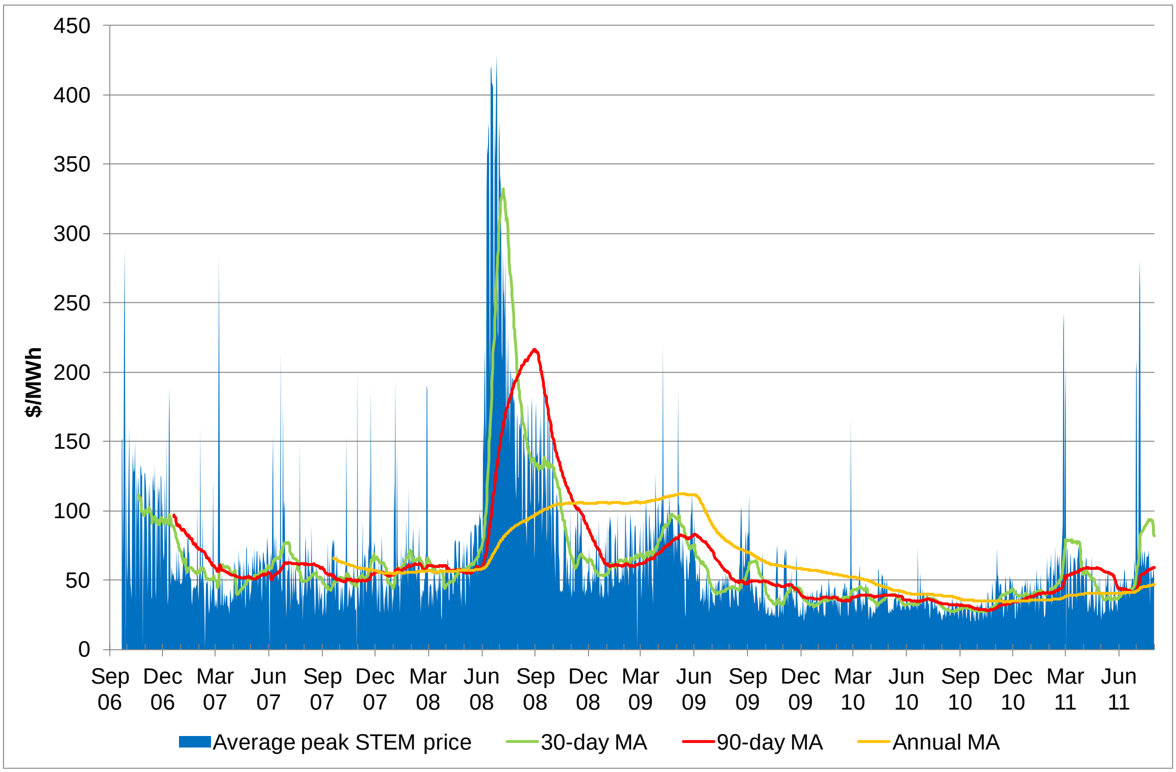
Most importantly, the Authority considers that STEM Clearing Prices have generally reflected the balance of supply and demand and, in doing so, have provided useful price signals to Market Participants.

The figures below illustrate, respectively, average daily peak and off-peak STEM Clearing Prices for each Trading Day from 21 September 2006 (market commencement) up to 31 July 2011. These figures also show 30-day, 90-day, and annual moving average prices.

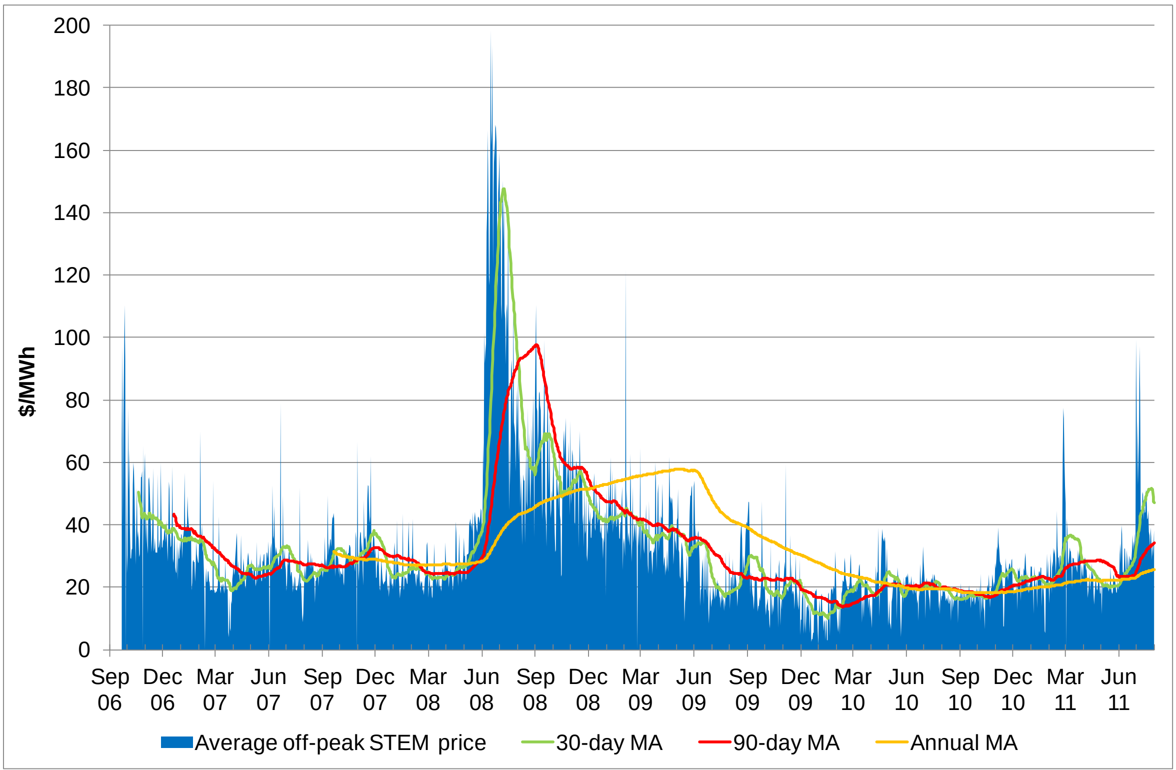
Following a period of high prices immediately after market commencement, STEM Clearing Prices were relatively stable in 2007 and in 2008, prior to the Varanus Island incident in June 2008. Following the incident and the subsequent curtailment of gas supplies, prices increased significantly, peaking at a daily average in excess of $400/MWh during Peak Trading Intervals and a daily average of close to $200/MWh during Off-Peak Trading Intervals. Prices have trended down since that time. The average STEM price between 1 October 2008 and 31 July 2011 is approximately $50/MWh during Peak Trading Intervals and approximately $27/MWh during Off-Peak Trading Intervals.

However, significantly higher prices were observed in late February and early March 2011, and again in late June and early July 2011. The higher average daily prices in late February and early March 2011 coincided with the shut-down of production at Varanus Island due to the effects of Cyclone Carlos. This gas supply disruption affected a number of gas fired generation facilities in the SWIS and led to the declaration of a High Risk Operating State from 23 February 2011 until 1 March 2011 by System Management, and to the dispatching of Curtailable Load during this period. The Authority notes that the higher average daily prices in late June and early July 2011 coincided with a large number of generators being given approval to take planned outages. As discussed in Section 2.4, the Authority has some concerns surrounding the rate of planned outages being taken by some generators and the consequential price impact observed in the market.

Average Peak Trading Interval STEM Clearing Prices (per Trading Day)



Average Off-Peak Trading Interval STEM Clearing Prices (per Trading Day)



While the current STEM design has its limitations, and volumes traded through the STEM remain relatively low, the Authority's view is that a transparent wholesale price, such as that provided by STEM Clearing Prices, is an important feature of an effective energy market, particularly in facilitating new investment. Currently the STEM is the only information mechanism through which new entrants can discover information about demand and pricing in the market.[8] This is an important function, enabling new entrants to make decisions about entry and investment. The Authority considers that a transparent and competitive energy market is essential to the achievement of the Market Objectives.

[8] The Displacement Mechanism under the original Vesting Contract required Synergy to publish specific quantity and price information that were useful for the price discovery of potential investors in the market. However, this mechanism was abolished with the implementation of the Replacement Vesting Contract in October 2011.

Summary of Recommendations and Findings

Finding 1

Section 2.1

A merger between Synergy and Verve Energy would result in a competitive detriment in the WEM.

Recommendation 1

Section 2.3

The treatment of Demand Side Management in the Wholesale Electricity Market should be reviewed by the Reserve Capacity Mechanism Working Group.

Given the materiality of this review, and reflecting the Authority's recommendations on the Rule Change Process, the Authority recommends that the Public Utilities Office should be involved in the working group and ensure that the outcomes of the working group are consistent with broader energy market policy.

The working group's consideration of the treatment of Demand Side Management should consider the merits of models adopted in other jurisdictions, including the option of changing the payment received by Demand Side Management to reflect the value provided by Demand Side Management.

Recommendation 2

Section 2.4

The incentives for plant availability created by the inter-relationship between the Reserve Capacity Mechanism and Reserve Capacity Refund payments should be reviewed by the Reserve Capacity Mechanism Working Group.

Specifically, the working group should consider whether the design of the Reserve Capacity Mechanism provides appropriate incentives for plant availability and whether a refund regime that links refund payments to system conditions would improve incentives for availability.

Recommendation 3

Section 2.6

The existing governance arrangements in the Wholesale Energy Market should be reviewed to determine whether the existing arrangements remain appropriate for the ongoing development of the market. The review should be undertaken by the Public Utilities Office, with input from all stakeholders.

Finding 2

Section 2.6

Achieving effective outcomes in the Wholesale Electricity Market requires clear guidance on the future policy direction from Government. This policy direction needs to be provided through the finalisation of the Strategic Energy Initiative, and thereafter on an ongoing basis.

Recommendation 4

Section 2.6

The review of existing governance arrangements in the Wholesale Energy Market should recommend policies to govern the transparency of information and material related to the consideration of Rule Change Proposals.

Recommendation 5

Section 2.6.4

The review of existing governance arrangements in the Wholesale Energy Market should determine whether the existing arrangements for both rule changes and procedure changes remain appropriate for the ongoing development of the market.

INTRODUCTION

1 Background

1.1 Reporting requirements for the Report to the Minister

The *Wholesale Electricity Market Rules* (**Market Rules**)[9] require the Economic Regulation Authority (**Authority**) to provide to the Western Australian Minister for Energy (**Minister**) a report (**Report to the Minister**) on the effectiveness of the Wholesale Electricity Market (**WEM**) in meeting the Wholesale Market Objectives (**Market Objectives**), at least annually.[10]

The Market Objectives are:

- to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system (**SWIS**);[11]
- to encourage competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors;
- 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;
- to minimise the long-term cost of electricity supplied to customers from the SWIS; and
- to encourage the taking of measures to manage the amount of electricity used and when it is used.

This report fulfils the Authority's requirements under the Market Rules.

Details of the Authority's reporting requirements and where these requirements are addressed in this report are provided in Appendix 1.

1.2 Process

The Authority released a Discussion Paper[12] on 25 October 2011 seeking public submissions on any strategic, policy or high-level issues that are impacting on the effectiveness of Western Australia's wholesale electricity market in meeting its objectives,

[9] See State Law Publisher website, Electricity Industry (Wholesale Electricity Market) Regulations 2004: Wholesale Electricity Market Amending Rules (September 2006), http://www.slp.wa.gov.au/gazette/GAZETTE.NSF/searchgazette/43EDE36827EBE11F482571ED0023C9C5/$file/gg161.pdf

[10] Pursuant to clause 2.16.11 of the Market Rules, the report must be produced at least annually, or more frequently where the Authority considers that the WEM is not effectively meeting its Market Objectives.

[11] The SWIS is defined in the *Electricity Industry Act 2004* and refers to the interconnected transmission and distribution systems located in the South West of the State, extending between Kalbarri, Albany and Kalgoorlie. See the State Law Publisher website, *Electricity Industry Act 2004*, http://www.slp.wa.gov.au/pco/prod/FileStore.nsf/Documents/MRDocument:17924P/$FILE/ElecityIndusAct2004_02-a0-00.pdf?OpenElement

[12] See ERA website, Discussion Paper - Annual Wholesale Electricity Market Report to the Minister for Energy - October 2011, http://www.erawa.com.au/cproot/9997/2/20111025 Discussion Paper - Annual Wholesale Electricity Market Report to the Minister for Energy.pdf

including on matters raised in the 2011 Annual Wholesale Electricity Market Report to the Minister for Energy. A notice was posted on the Authority's website advising the release of the Discussion Paper and interested parties were invited to make submissions to the Authority by 23 November 2011. A list of stakeholders who made submissions is provided in Appendix 2. The submissions received are available on the Authority's website.[13]

In preparing this Report to the Minister, and in forming the views set out in it, the Authority has considered the comments raised in the submissions provided to the Authority.

In accordance with the Market Rules, the Independent Market Operator (**IMO**) has provided the Authority with data and analysis relating to the WEM, which is summarised in Section 5 of this Report to the Minister. In forming the views set out in this report, the Authority has considered the data and the analysis provided by the IMO.

1.3 Confidentiality

Clause 2.16.15 of the Market Rules requires that, where the Authority provides a report to the Minister in accordance with Clause 2.16.11, the Authority must, after consultation with the Minister, publish a version of the report which has confidential or sensitive information aggregated or removed.

Information that is classified as confidential under Chapter 10 of the Market Rules has been identified by the Authority and will be aggregated or removed in the public version. This report is the confidential version to the Minister.

1.4 Structure of this report

This report is structured as follows:

- Section 2 sets out the Authority's assessment of any specific events, behaviour or matters that impacted on the effectiveness of the market;
- Section 3 provides a summary of the Authority's monitoring activities on the effectiveness of the market in meeting the Market Objectives;
- Section 4 sets out the Authority's assessment of the operational effectiveness of the market, including the effectiveness of the IMO and System Management in carrying out their functions; and
- Section 5 provides a summary of the data identified in the Market Surveillance Data Catalogue (**MSDC**) and the analysis of that data undertaken by the IMO.

[13] See ERA website, Annual Wholesale Electricity Market Report to the Minister for Energy web page, http://www.erawa.com.au/2/532/42/annual_wholesale_electricity_market_report_to_the_.pm

PART A

2 Authority's assessment of any specific events, behaviour or matters that impacted on the effectiveness of the Wholesale Electricity Market

Clause 2.16.12(c) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of any specific events, behaviours or matters that have impacted on the effectiveness of the WEM. Clause 2.16.12(d) of the Market Rules requires that the Report to the Minister also contains any recommended measures to increase the effectiveness of the market in meeting the Market Objectives. This section sets out the Authority's assessment and recommendations.

The WEM commenced operation in September 2006. The WEM was introduced as part of a suite of electricity industry reforms implemented by the WA Government following a review of the industry.[14] The WEM design was intended to be a 'low risk' and 'low cost' option based upon considerations of maintaining security of supply, and providing operational simplicity and the flexibility to implement incremental changes.

In previous reports to the Minister, the Authority has considered that the WEM has generally operated effectively since market commencement.

In its Discussion Paper for this year's Report to the Minister, the Authority noted that there has been a shorter period than usual between the release of the previous Minister's Report and the commencement of public consultation for this Minister's Report. The Authority provided the 2010 Report to the Minister in May 2011 and the public version of the Report was published in August 2011.

The Authority recognises that stakeholders have had less time than usual to consider the analysis and the recommendations set out in the 2010 Report to the Minister and to consider the extent to which emerging issues in the market have been addressed in the 2010 Report to the Minister.

For this reason, in the Discussion Paper, the Authority highlighted specific issues that have been subject to ongoing development since the Authority undertook consultation for, and prepared, the 2010 Report to the Minister. The Authority stated that it is particularly interested in stakeholders' views on the following issues:

- the possible merger of Verve Energy and Synergy
- the impact of climate change policies
- the impact of Demand Side Management (**DSM**)
- the effectiveness of the outage planning process
- the effectiveness of the Market Rules change process
- the market for Bilateral Contracts and their influences on market outcomes.

[14] Other key reforms included: the disaggregation of Western Power into four separate Government owned entities; the reduction in the retail contestability threshold to 5.7 kW; and the introduction of a number of other transitional arrangements, including measures to mitigate the market power of Verve Energy and Synergy to coincide with the commencement of the WEM.

The Authority's discussions with stakeholders since the release of the Discussion Paper, and stakeholders' submissions to the Discussion Paper, confirm that the issues that currently are of most concern to stakeholders are captured by the Authority's list of key issues. Given this, this section primarily focuses on these key issues:

- Section 2.1 considers the potential merger of Verve Energy and Synergy, and the effects that this would have on the WEM;
- Section 2.2 considers the role of the Reserve Capacity Mechanism (**RCM**) in the WEM;
- Section 2.3 considers the role of DSM in the WEM;
- Section 2.4 considers the effectiveness of the reserve capacity performance monitoring measures and the outage planning process;
- Section 2.5 considers climate change policies, and whether the design of the WEM will continue to promote the Market Objectives, given the implementation of these climate change policies; and
- Section 2.6 considers governance arrangements in the WEM, including the role of the IMO and the Public Utilities Office[15] in the Market Rules change process.

2.1 Potential merger of Verve Energy and Synergy

In its Discussion Paper, the Authority noted that the Government of Western Australia has recently stated that it is considering merging Verve Energy and Synergy.

This follows recognition of the significant rise in retail electricity prices that has occurred since the break-up of the old Western Power Corporation and the assumption that a merger between Verve Energy and Synergy might reduce pressure on prices.

Comments have also been made suggesting that:

- the return to taxpayers from government ownership of Verve Energy and Synergy may be adversely impacted by the separation of Verve Energy and Synergy;
- Verve Energy and Synergy have missed opportunities because they have effectively been in competition with each other;
- privately-owned generators in the market are being subsidised and this is occurring while Verve Energy's generators are sitting idle; and
- merging Verve Energy and Synergy would better promote the security of the electricity supply in the SWIS.

The Authority's views on these matters are set out below.

2.1.1 Retail electricity prices

The Authority is aware that retail electricity prices have increased by 57 per cent in recent years, but considers that these increases were inevitable, regardless of how the disaggregation of the old Western Power was structured (i.e., whether Verve Energy and Synergy remained as one or separate government trading entities). The Authority notes that the increase in residential retail tariffs in 2009/10 was the first tariff increase since

[15] The Public Utilities Office, which will operate under the Department of Finance, will take over responsibility for energy policy as of 30 March 2012. The Office of Energy, which has had responsibility for energy policy in the past, will cease to exist as of 30 March 2012.

1997/98 (meaning that tariffs had not even kept pace with inflation since 1997/98)[16] and considers that the recent increases have been driven by increases in the underlying costs of supplying electricity to retail customers. These underlying cost pressures included increased fuel costs faced by generators, increased network charges, and the costs to retailers of complying with the Commonwealth Government's renewable energy policies.

The Authority's recently released draft report on the Inquiry into the Efficiency of Synergy's Costs and Electricity Tariffs has indicated that the pressure for further tariff increases will moderate although there is still some cost catch-up required to achieve cost reflectivity. The Authority has estimated that the regulated tariffs, averaged across all customer groups, would need to increase by 15.8 per cent in 2012/13 (including 8.2 per cent for the introduction of the carbon tax) to ensure that taxpayers are not covering the gap between efficient cost and revenue earned by Synergy. Given that network charges make up approximately one third of total electricity costs, the Authority's estimate has taken into account the Authority's draft decision on Western Power's third access arrangement[17], which has indicated that network costs should not be adding any pressure to retail electricity tariffs in the next five years from 1 July 2012 to 30 June 2017.

Had Verve Energy and Synergy been merged following disaggregation, the Authority's view is that this would not have diminished the underlying cost pressures facing the electricity supply industry in a meaningful way. Certainly there may have been some saving in corporate overheads, but these are unlikely to have been material in comparison to the costs of fuel, the network, carbon and renewable energy policies (the saving in corporate overheads is likely to amount to less than $3 for a typical household's annual electricity bill). For similar reasons, the Authority's view is that future retail electricity prices will not be materially reduced by the proposed merger. Indeed, it is the Authority's view that a merger could result in a significant detriment to the development of competition in the WEM. A merger would create a dominant organisation in the market with significant market shares in both generation and retailing. This is likely to lead to a reduction in transparency and the opportunity for anti-competitive behaviour (e.g., by favouring internal counter-parties). This would create barriers to market entry, thereby reducing the private investment and innovation required for the promotion of cheaper alternatives. Thus, it is the Authority's view that the proposed merger would ultimately result in higher prices for electricity customers.

The Authority considers that the most effective way of ensuring that the costs of supplying electricity to retail customers are minimised is to promote competition in generation and retailing. This will create pressure for generators and retailers to minimise their costs in order to compete in the market. In previous Reports to the Minister, the Authority has made a number of recommendations intended to promote greater competition, including introducing full retail contestability, an investigation of the competitive implications of the Replacement Vesting Contract (**RVC**) between Verve Energy and Synergy, and a review of the overall level of competition in the market. Rather than increasing competition and reducing prices, the Authority's view, as noted above, is that the proposed merger of Verve Energy and Synergy would set back competition in both generation and retailing, which would be to the detriment of achieving competitive electricity prices.

[16] Government of Western Australia Office of Energy, *Electricity Retail Market Review*, Final Recommendations Report, January 2009.

[17] Network charges make up approximately 40% of the total electricity costs for residential customers. The Authority's draft decision sets a cap of $6.8 billion on the revenue Western Power can earn over the next five years.

2.1.2 Benefits to taxpayers

The Authority understands that the Government is concerned that taxpayers may not be receiving an appropriate return for the ownership of Verve Energy and Synergy, given their separation.

The Authority is aware that, following disaggregation, Verve Energy experienced cash-flow losses in the 2007/08 and 2008/09 financial years. The Authority considers that these losses resulted from electricity retail prices that were at less than cost reflective levels, leading to insufficient revenue to cover the operating costs incurred by both Synergy and Verve Energy. Either Synergy or Verve Energy had to wear the costs and it was Verve Energy who ultimately did. This situation was further exacerbated by the 2008 Varanus Island incident,[18] which caused a spike in fuel costs that Verve Energy was unable to pass-through to Synergy, under the original Vesting Contract (**VC**).

The Authority notes the changes that occurred in Verve Energy's financial position as follows.

- For the 2008/09 financial year, Verve Energy reported a loss of $239 million. This was partly as a result of the Varanus Island incident, which required Verve Energy to burn a significant amount of diesel fuel (at greater cost than gas). However, due to the Netback arrangement under the VC, Verve Energy was unable to pass the increased fuel costs onto Synergy in that year.
- For the 2009/10 financial year, Verve Energy reported a profit before tax of $138 million, a turn-around of $377 million on the previous year. The energy sales revenue that Verve Energy received from Synergy under the VC increased by 22 per cent from $924 million in the 2008/09 financial year to $1,125 million in the 2009/10 financial year, presumably as a result of the increase in electricity prices that had occurred.
- For the 2010/11 financial year, Verve Energy reported a profit before tax of $185 million, representing a 34 per cent increase on the 2009/10 result. Presumably, this was as a result of both the increase in electricity prices and the RVC, which took effect in October 2010.

The Authority notes that one of the primary reasons for replacing the original VC with the RVC was to improve the financial position of Verve Energy.[19] In part, this followed the

[18] Between June and December 2008, a major disruption to natural gas supply in Western Australia occurred. The disruption was caused by the rupture of a corroded pipeline and subsequent explosion at a processing plant on Varanus Island, off the State's North West coast, on 3 June 2008. The plant, operated by Apache Energy, which normally supplied a third of the state's gas, was shut down for almost two months while repairs were carried out. Gas supply from the plant was partially resumed in late August 2008. By mid-October 2008, gas production was running at two-thirds of normal capacity, with 85 per cent of full capacity restored by December 2008. Due to the State's heavy reliance on continuous supply of gas for industrial processing, manufacturing, residential use and electricity generation, the sudden loss of almost a third of the gas supply had immediate social impacts, and significant short and long-term economic effects.

[19] Upon disaggregation of the old Western Power Corporation in April 2006, Vesting Arrangements commenced as a transitional mechanism intended to support the development of a competitive electricity market in Western Australia. These arrangements included a VC (2006) that provided for the initial wholesale electricity supply from Verve Energy to Synergy. The timetable for the VC's 'Displacement Mechanism' determined when the VC was due to expire, which was within three years of the introduction of Full Retail Contestability (FRC) in the SWIS. Under the Displacement Mechanism, Synergy's load volumes were progressively exposed to competitive sourcing, with Verve Energy and Independent Power Producer's being able to tender for these volumes. At the time the VC was put in place FRC was to be introduced once the WEM was 'efficient' and at that time there should be no further need for the VC. The VC was terminated in October 2010 and replaced with the RVC. The Government considered that, among other reasons, the VC needed to be replaced as it had directly resulted in the significant financial losses incurred by Verve Energy between the 2006/07 and 2008/09 financial years.

recommendations of the Verve Energy Review (also known as the Oates Report),[20] which raised concerns about the 'netback' arrangements[21] in the VC, which directed any revenue shortfall in the electricity tariffs to Verve Energy. Whilst recognising that Verve Energy has greater capacity than Synergy to absorb such a shortfall, the Oates Report concluded that a bilateral arrangement that is aligned with general commercial contracts between Verve Energy and Synergy would be preferred. Nevertheless, it is noteworthy that Verve Energy reported a net profit of $138 million for the 2009/10 financial year, and therefore a benefit to taxpayers, even before the RVC was implemented.

The Authority notes that there has been a claim of a $1 billion benefit associated with the introduction of the RVC. It is understood that the $1 billion figure was based on work undertaken by Deloitte to calculate the impact of the RVC on the State Government's finances. In particular, the analysis calculated the likely impact on dividends and tax payments to the State Government from both Verve and Synergy and also calculated the likely impact on net debt. It is understood that the $1 billion benefit was calculated by adding the dividend, tax and net debt benefits together and projecting these estimates forward for a ten year period.

The Authority considers that the RVC is merely a revised arrangement for allocating profits and cash flow between Verve Energy and Synergy. It is not clear to the Authority how a change of profit allocation arrangement between two companies can result in such a large net increase in the combined profit of the two companies, unless it has built in significant revenue increases and hence higher prices paid by consumers in the underlying modelling assumptions.

While the Authority has no access to the assumptions underlying the $1 billion claim, the Authority notes that benefits to the State's finances do not necessarily represent benefits to the State as a whole. The main reason for this is that the improvement in the State's finances is expected to be derived from higher electricity tariffs. While taxpayers may benefit, this benefit will be at the expense of electricity consumers, most of whom are these same taxpayers.

2.1.3 Competition between Verve Energy and Synergy

While Verve Energy and Synergy do not directly compete with one another in an economic sense (because Verve Energy is prevented from selling electricity and Synergy is prevented from generating electricity) it is certainly the case that Verve Energy and Synergy may have competing corporate objectives. These competing objectives may result in Synergy taking actions that are detrimental to Verve Energy, and vice versa. For instance, a decision by Synergy to procure capacity or electricity from a generator other than Verve Energy may increase Synergy's profits (by reducing its costs) but at the same time decrease Verve Energy's profits (by reducing its revenues); this was the case with Bluewaters 2.

It is the Authority's view that if Verve Energy and Synergy were to merge, and potentially increase their profits, this would reduce competition and most likely lead to higher

[20] See Office of Energy website, *Verve Energy Review (August 2009)*, http://www.energy.wa.gov.au/cproot/1571/14895/Verve Energy Review Final Report August 2009.pdf

[21] The Netback Pricing under the VC was based on a 'netback calculation', which meant that Verve Energy was paid the residual of Synergy's sales revenues less efficient retail, networks, and other costs. That is, Synergy paid Verve Energy fixed and variable prices so that Verve Energy received the equivalent of: the revenue Synergy received from the relevant tariff and contract sales; less a defined allowance for Synergy's costs, including an efficient profit margin, which was retained by Synergy; less regulated networks costs paid to the Electricity Networks Corporation (Western Power); and less other specified market and regulatory costs.

electricity tariffs for electricity customers. For instance, if a merger proceeds then the retail business may be prevented from procuring capacity or electricity from competing generators at lower cost. The result of this will not only be higher costs to the retail business (which may or may not be outweighed by higher revenues to the generation business) but also higher electricity prices for end-users.

It may be possible to have Synergy procure capacity or electricity in a way that is ring-fenced from Verve Energy. However, this would require considerable regulatory oversight and may stifle the innovation and transparency that a competitive market would bring. Moreover, it would make it more difficult to achieve efficient outcomes, given the challenges associated with overcoming the lack of trust that Independent Power Producers (**IPP**) will have in the tendering arrangement, thereby creating barriers to entry, and reducing the participation of providers that offer cheaper alternatives (e.g., the commissioning of the Bluewaters units).

2.1.4 Operation of Verve Energy's plant

The Authority's view is that two key factors have led to the situation whereby Verve Energy's plant is being idled at times, particularly overnight. These two factors are recent increases in wind generation and excess base-load generation capacity in the market.

Since market commencement, three base-load generation facilities have been commissioned into the market. NewGen's Kwinana gas-fired generation facility (320 MW), commissioned in 2008/09, was underwritten by the old Western Power Corporation as part of its power procurement program. Griffin Power's first coal-fired unit at the Bluewater Power Station (240 MW), also commissioned in 2008/09, was driven by a major mining investment in the local area, under a commercial arrangement between Griffin Power and Boddington Gold Mines. Griffin Power's second coal-fired unit at the Bluewater Power Station (240 MW) was commissioned in 2009/10. The development of this unit was brought to the market by Synergy's procurement process, required by the Displacement Mechanism under the original Vesting Contract, following a competitive tendering process in which Verve Energy unsuccessfully participated. It was the commissioning of this second unit, that has been seen as having created some excess base-load generation in the market. This, however, has also brought cheaper energy to the market, with the ultimate benefit to consumers, as Synergy was able to procure electricity supply from Griffin Power at lower prices than offered by Verve Energy. Other Market Participants have also benefited from the lower energy price as a result of the commissioning of Griffin Power's second unit, as is indicated by the lower STEM and balancing prices observed in the market.

The Authority recognises the impact of recent increases in renewable energy projects resulting from climate change policies at both the State and Federal levels. Policy considerations at market commencement ensured that rules were put in place to make the market more flexible and allow for the inclusion of intermittent generators. In line with this, there has been a shift in the energy sector from traditional thermal generation to cleaner renewable energy generation.

Over the past five years, close to 400 MW of wind generation, that is capable of displacing base load capacity, has been installed in the SWIS. One of the challenges brought by these wind generation facilities is that they often produce at high output levels overnight when demand is low. As a result, there has been strong competition among base-load generation plants to supply overnight, which has resulted in some occurrences of negative prices. Furthermore, Verve Energy's facilities have been the first to be turned-down when required, as Verve Energy is currently the default provider of Balancing services (an arrangement made at the commencement of the WEM).

The Authority's view is that a merger of Verve Energy and Synergy would not avoid the situation of Verve Energy's plants sitting idle overnight. Rather, the current excess base-load generation will eventually be resolved by load growth. Furthermore, the introduction of a competitive Balancing market from July 2012 is intended to provide an opportunity for both Verve Energy and private generators to supply Balancing services to the market on a competitive basis, resulting in a more efficient use of available generators.

2.1.5 Security of supply in the SWIS

It is unclear to the Authority why a merger of Verve Energy and Synergy would be expected to promote security of supply in the SWIS.

The Authority notes that the WEM was designed with a focus on ensuring security of supply in the isolated electricity market in Western Australia. In particular, the inclusion of a capacity market within the structure of the WEM was intended to ensure that there remained adequate capacity in the market. As discussed in this Report to the Minister and in each previous Report to the Minister, the WEM has been very successful in ensuring security of supply. In each Capacity Year there has been more than adequate capacity available to meet the IMO's forecast capacity requirement. Furthermore, there have been no reported instances of lost load due to shortages in the capacity procured since the commencement of the RCM. This has been achieved in the context of significantly increased participation by independent generators.

The Authority is aware of gas supply agreements, signed by Verve Energy and Synergy with the Gorgon Joint Venture participants[22] that have variously been described as being vital to the reliability and security of the domestic energy supply, delivering energy security and promoting energy supply for the state for decades. The 20-year agreements, for a combined 125 terajoules a day, will be activated to coincide with Verve Energy and Synergy's gas supply arrangements, expiring in or around 2015-16.

It might be thought that long-term gas supply agreements such as these would be easier to obtain for a merged entity, with a larger balance sheet, and the ability to attract suppliers by taking on larger contracts. However, even in the absence of the merger, both Verve Energy and Synergy would still be viewed by suppliers as having a low credit risk, as a result of being Government owned.

2.1.6 Effect of a merger on the Wholesale Electricity Market

The Authority has commented in its 2009 Report to the Minister that a merger of Verve Energy and Synergy would deter the entry of new generators and retailers in the WEM, thereby destroying effective competitive tension in the market. Ultimately, Western Australian electricity customers would bear the risks and costs of a shift to a gentailer with significant market power.

In discussions with the Authority and in submissions to the Discussion Paper, stakeholders raised significant concerns with the proposed merger of Verve Energy and Synergy. Three concerns were commonly raised.

- Firstly, a merger would significantly reduce the ongoing development of competition in the WEM, at both the generation and retail levels. Alinta commented that a merger of Verve Energy and Synergy would provide a strong disincentive for the merged entity to enter into transactions with other generators,

[22] http://www.wa.liberal.org.au/item/8344.

which would ultimately create a significant risk that existing levels of competition in the generation and retail segments of the WEM would be undermined.

- Secondly, a merger would result in a significant loss of value for private sector investors in the WEM. Landfill Gas and Power (**LGP**) commented that investment in generation since market commencement has taken place in the expectation that the market power of Verve Energy and Synergy would be constrained. Because a merger would provide a strong disincentive for the merged entity to enter into transactions with other generators, the commercial position of those independent generators already in the market would be worsened. This would result in a significant detriment to the development of competition in the WEM and, in the longer term, would ultimately result in higher prices for electricity customers.
- Lastly, a merger would increase the perception of regulatory risk in the WEM. A number of stakeholders commented that a merger of Verve Energy and Synergy would constitute a substantial reversal in policy and, given the negative consequences for private sector investors, this would increase the perception of political risk associated with investing in the power sector in Western Australia.

In addition, System Management considers that a merger would require further consideration of arrangements regarding governance, reserve capacity, registration, settlements and facility dispatch.

The Authority remains very concerned about the potential for a competitive detriment to arise as a result of a merger between Verve Energy and Synergy. The Authority is concerned that a merged Verve Energy and Synergy would be able to impede its competitors' access to commercial opportunities in the electricity market. For instance, the retail arm of the merged entity may favour the generation arm over competing generators when it comes to contracting for electricity supply. Similarly, the generation arm of the merged entity may favour the retail arm when it comes to contracting. The effect of this would be to make it more difficult for competing generators and retailers to secure contracts on competitive terms. Given the importance of securing bilateral contracts for both independent generators and retailers in the WEM, this would affect the commercial returns of those competing generators and retailers that have already invested in the market and also would be likely to deter entry by new generators and retailers.

The Authority has previously considered the issue of vertical integration between generators and retailers, and concluded that vertical integration can lessen competition where a business has significant market share in one segment of the market that can be leveraged to the advantage of the business in the other market segments.[23] The Authority noted that regulatory bodies have opposed the cross-ownership of generation and retail businesses (when one or both of these businesses has a large market share) due to the detrimental impact on competition. In particular, the Authority noted that studies of electricity markets have found that:

- while vertical integration is not anti-competitive *per se*, "anti-competitive problems may arise where it is associated with excessive horizontal aggregation" (i.e., where one company has a large market share in generation or retail);[24]
- while there are benefits at the generation level from vertical integration, this can be counterbalanced by the cost (to the consumer) of increased retail margins;[25]

[23] Economic Regulation Authority, *Prohibition and Restriction on Synergy and Verve Energy under the Electricity Corporations Act 2005*, Final Report, 20 April 2011. (not publicly available yet)

[24] Energy Reform Implementation Group 2007, Energy Reform: The way forward for Australia: a report to the Council of Australian Governments.

- the behaviour of a ‘gentailer’ is less observable by regulators and the public at large than the behaviour of separate generation and retailing companies, giving the gentailer greater opportunities to extract economic rent;[26] and
- new entrants have difficulties in securing adequate wholesale electricity supplies to provide sufficient ‘rivalry’ to incumbent gentailers and often exit the market, while incumbent gentailers charge relatively higher prices to customers who reside in incumbents’ former monopoly areas.[27]

Importantly, the Authority’s concern about the effects of a merger between Verve Energy and Synergy does not reflect a more general concern about all vertical integration between generators and retailers in the WEM. Rather, the Authority’s concern about a merger between Verve Energy and Synergy is based on the particularly large market shares of Verve Energy in the generation sector (i.e., 51 per cent in 2013 in terms of certified capacity) and Synergy in the retail sector (i.e., 71 per cent in the 2010/11 financial year, as measured by sales volume).

Given these market shares, Verve Energy and Synergy remain very important contract counterparties in the WEM. As outlined in Table 6 of Section 5.3.1, which shows the annual average quantities (MWh) traded in Bilateral Contracts (scheduled with the IMO), Bilateral Contracts between Verve Energy and Synergy dominate the market. For sellers other than Verve Energy (competing generators), Synergy is a more common counterparty than all other buyers combined. Over the last four years, Synergy has, on average, been counterparty to 53 per cent of the quantity traded in Bilateral Contracts involving other sellers. For buyers other than Synergy (competing retailers), Verve Energy is an important counterparty. Over the last four years, Verve Energy has, on average, accounted for 38 per cent of the quantity traded in Bilateral Contracts involving other buyers.

It is the importance of Verve Energy and Synergy as counterparties to other generators and retailers in the WEM that lies behind the Authority’s concern about the merger of Verve Energy and Synergy. If there was a merger between Verve Energy and Synergy other parties would be likely to consider that there is significantly greater risk in securing bilateral contracts in the WEM and/or significantly greater risk about the competitiveness of the terms of bilateral contracts. For this reason, the Authority reiterates that it has significant concerns about the effect of the proposed merger of Verve Energy and Synergy on the ongoing development of competition in the WEM. Ultimately, the Authority would expect that reduced competition would be to the detriment of the efficiency of market outcomes and tend to result in higher prices over time for electricity customers.

[25] See for example, Giulietti, M., Grossi, L., and M. Waterson, 2010. "Price transmission in the UK electricity market: was NETA beneficial", Energy Economics, Vol.32 (5), pp. 1165-74. The results showed that the six major gentailers have significant ‘pricing latitude’ at the retail level. Note that 70 per cent of customers remain with one or other of the former monopoly suppliers, with some customers having negotiated better terms (Ofgem 2008. Energy Supply Probe; Initial Findings Report, October 2008).

[26] Gentailers can utilise a lack of price transparency and cross-subsidisation and have the ability to pass-through higher wholesale prices to end users. In New Zealand, three of the largest gentailers are government owned. Wholesale prices over the period 2001-07 were found, on average, to be 18 per cent higher than they would have been if the wholesale market had been more competitive and the gentailers had not been able to exert market power. The New Zealand Commerce Commission also found that the ‘exercise of market power in the wholesale market appears to have been passed through in the form of higher retail prices’. Commerce Commission 2009, Investigation Report, Commerce Act 1986 S27, S30 and S36: Electricity Investigation, May 2009.

[27] Ofgem 2008. Energy Supply Probe; Initial Findings Report, October 2008. The report found there was no cost basis for charging a premium to these customers.

Finding 1

Section 2.1

A merger between Synergy and Verve Energy would result in a competitive detriment in the WEM.

2.2 Reserve Capacity Mechanism

The RCM underpins the operation of the capacity market, an important feature of the WEM structure. The RCM requires that retailers either secure adequate capacity bilaterally through the market, or purchase it from the IMO. In this way the RCM provides a guarantee of payment to investors that provide certified capacity to the market.

As a result of its work in monitoring the WEM, and discussions with stakeholders that were conducted as part of its annual Reports to the Minister, the Authority is aware of a number of issues related to the RCM. Broadly, these issues fall within three categories.

- The cost to the market of the capacity secured under the RCM. This is discussed in more detail in this section.
- The treatment of DSM in the RCM, including whether DSM should participate in the RCM and, if so, on what basis. This is discussed in more detail in section 2.3.
- The relationship between the RCM and plant outages, including whether the operation of the RCM is consistent with providing Market Participants with appropriate incentives to make their generation plant available. This is discussed in more detail in section 2.4.

2.2.1 Excess capacity

The RCM has been successful in securing sufficient capacity to meet forecast requirements in every Capacity Year since its inception. However, there has also been a material excess of Capacity Credits assigned to participants during this period. As can be seen in Table 1 the excess ranged from as low as approximately 2 per cent in the 2010/11 Capacity Year to a high of approximately 15 per cent in the 2013/14 Capacity Year, with an average excess over the 2007/08 to 2013/14 period of approximately 7.5 per cent.

Table 1 **Excess Capacity Credits assigned to Market Participants and Capacity Credits provided by DSM for the 2007/08 to 2013/14 Capacity Years**

Period	Reserve Capacity Requirement	Certified Reserve Capacity	Excess Capacity Credits	Excess Capacity Credits (%)	Capacity Credits provided by DSM
01/10/07 to 01/10/08	4,000	4,115	115	2.9%	131
01/10/08 to 01/10/09	4,322	4,600	278	6.4%	128
01/10/09 to 01/10/10	4,609	5,136	527	11.4%	99
01/10/10 to 01/10/11	5,146	5,259	113	2.2%	154
01/10/11 to 01/10/12	5,191	5,493	302	5.8%	260
01/10/12 to 01/10/13	5,501	5,996	495	9.0%	454
01/10/13 to 01/10/14	5,312	6,087	775	14.6%	500
Average			**372**	**7.5%**	

The issue of the cost of the excess capacity secured under the RCM to the market has been considered in previous Reports to the Minister. In the context of these Reports, some stakeholders have commented that the excess capacity results in additional costs to the market, which is ultimately borne by consumers. The Authority notes that there is a mechanism that partly affects the costs of the excess capacity to the market when there is no auction held. In this case, the administrative Reserve Capacity Price (**RCP**) is reduced in proportion to the excess capacity.[28] The adjustment for the administrative RCP is intended to make total costs of capacity the same as if there is no excess capacity.

However, in practice this equivalence is not achieved. This is because the reduction in the RCP will not necessarily be matched by a reduction in the capacity price bilaterally negotiated between buyers and sellers of capacity. For instance, where a Market Customer has already bilaterally secured a large proportion of its expected requirement for Capacity Credits, the bilaterally agreed price of those Capacity Credits may not be reduced in line with the reduction in the RCP. At the same time, the excess capacity also increases the number of Capacity Credits allocated to the Market Customer by the IMO. Consequently, the Market Customer will face a higher cost despite the reduction in the RCP.

Moreover, it is relevant to examine the recent general trend toward growth in excess capacity in the market and, in particular, to consider it within the context of the apparent growth in Capacity Credits provided by DSM. For example, as shown in the table above, the number of excess Capacity Credits assigned to Market Participants has grown from 302 MW in the 2011/12 Capacity Year to 775 MW in the 2013/2014 Capacity Year. At the same time, the Capacity Credits attributable to DSM have grown steadily from 260 MW in the 2011/12 Capacity Year to 500 MW in the 2013/14 Capacity Year. This is in contrast to the number of Capacity Credits that were attributable to DSM providers in the 2007/08 to 2010/11 Capacity Years, where the number was generally constant (averaging at around 128 MW per year). Given that DSM providers receive the same payments for capacity as generators (i.e., without having to provide the same level of services or having the same capital outlay), the Authority is concerned that there is a disparity between the benefits provided by DSM and the costs to the market. A more detailed discussion of the Authority's concerns in this regard is provided in Section 2.3.

[28] This is achieved by multiplying the Maximum Reserve Capacity Price by the Excess Capacity Adjustment, where the Excess Capacity Adjustment is equal to the Reserve Capacity Requirement for a Capacity Cycle divided by the total number of Capacity Credits assigned by the IMO for that Capacity Cycle. See Clause 4.29.1 of the Market Rules.

2.2.2 The Reserve Capacity Price

More recently, the issue of the cost to the market of the capacity secured under the RCM has tended to focus on the determination of the RCP and its linkage with the Maximum Reserve Capacity Price (**MRCP**). This was highlighted in the Authority's Discussion Paper, which noted that the implied cost to the market of the capacity secured under the RCM has increased significantly since its commencement (particularly for the 2012/13 and 2013/14 Capacity Years), and this has been driven in large part by increases in the MRCP.

The MRCP sets the maximum offer price for the Capacity Year for which a Reserve Capacity auction is being held. The MRCP is determined for each Capacity Cycle by the IMO and approved by the Authority. In the event that no Reserve Capacity auction is held for a particular Capacity Year, the MRCP is used to calculate the RCP (in this case the RCP is equal to 85 per cent of the MRCP multiplied by the Excess Capacity Adjustment).[29]

Since the commencement of the WEM in 2006, no Reserve Capacity auction has been held. Hence, the RCP has been calculated by the IMO based on the MRCP. The MRCPs over the period from the commencement of the RCM in 2006/07 to the 2013/14 Capacity Year are set out in Table 2. Based on these MRCPs, the corresponding RCPs and the total Capacity Credits in each Capacity Year, the implied value of Capacity Credits each Capacity Year are also set out in Table 2.

Table 2 Reserve Capacity Prices

Period	Reserve Capacity Price (per MW per year)	Maximum Reserve Capacity Price (per MW per year)	Implied value* of Capacity Credits (per year)
21/09/06 to 01/10/06	$127,500	$150,000	
01/10/06 to 01/10/07	$127,500	$150,000	$477m
01/10/07 to 01/10/08	$127,500	$150,000	$525m
01/10/08 to 01/10/09	$97,835	$122,500	$450m
01/10/09 to 01/10/10	$108,459	$142,200	$557m
01/10/10 to 01/10/11	$144,235	$173,400	$758m
01/10/11 to 01/10/12	$131,805	$164,100	$724m
01/10/12 to 01/10/13	$186,001	$238,500	$1,115m
01/10/13 to 01/10/14	$178,477	$240,600	$1,086m
01/10/14 to 01/10/15	$132,000	$163,900	$805m

** Note: The actual value of Capacity Credits settled under bilateral contracts is determined by the prices set in bilateral contracts. Reserve Capacity Price and implied value of Capacity Credits for the 2014/15 Capacity Year are estimates by the Authority.*

The Authority considers that significant increases in the MRCPs and the corresponding increase in the implied value of Capacity Credits adds cost pressure to consumers and is a concern for the market. In particular, as noted by Synergy in its submission to the

[29] See Clause 4.29.1 of the Market Rules.

Authority's Discussion Paper, an increase in the price of Capacity Credits results in direct costs to the market and to consumers.

The Authority notes that the MRCP for the 2014/15 Capacity Year at $163,900 per MW per year, which has been recently approved by the Authority, represents a significant reduction from the price levels for 2012/13 and 2013/14 Capacity Years (i.e., the MRCP for the 2014/15 Capacity Year is approximately one third less than the MRCPs for the two preceding years). The Authority also notes that the MRCP for the 2014/15 Capacity Year is better aligned with the long term MRCP trend and, in that context, the 2012/13 and 2013/14 Capacity Years MRCPs can be considered to be outliers.

Given these recent changes, the Authority expects that the cost of capacity secured under the RCM is likely to be lower in future.

Furthermore, the Authority understands that the recently formed Reserve Capacity Mechanism Working Group (**RCMWG**) will be considering possible amendments to the way that the capacity price is determined. One option under consideration is to increase the rate at which the RCP is reduced in circumstances of excess capacity (in order to provide a greater price reduction in circumstances of excess capacity). The Authority recognises that a mechanism that results in lower capacity prices during periods of excess capacity is likely to be more reflective of competitive market outcomes, should a market auction be held. However, the Authority notes that the original intention of the RCM was to ensure adequate investment in capacity. Reducing the predictability of the capacity prices received by generators has the potential to undermine incentives for investment in capacity. For this reason, the Authority considers that the RCMWG should carefully assess the likely effects of any changes to the RCM on incentives for investment.

2.3 Demand Side Management

Over the most recent Reserve Capacity Cycles there has been a significant increase in Capacity Credits provided by DSM providers. This has resulted in substantial payments to DSM providers for the capacity that they are providing, and has resulted in questions about the value that the market receives in return for these payments. While there have been a number of reviews relating to DSM in previous years, these have not focused on this broader question of whether the cost of DSM to the market is justified by the benefits and, if not, what this implies about the appropriate role of DSM in the WEM.

Given that DSM is able to receive the same payments for providing capacity as are generators, this increase in DSM in the WEM comes at a significant cost. At the current Reserve Capacity Price of $131,805 per MW per year, the implied cost of the Capacity Credits provided by DSM amounts to $34 million (for 260 MW of capacity). By 2013/14, with a Reserve Capacity Price of $178,477 per MW per year, the implied cost of Capacity Credits provided by DSM will have increased to $89 million (for 500 MW of capacity).[30]

These recent increases in the implied cost of Capacity Credits provided by DSM raises the question of the appropriate role of DSM in the WEM and, in particular, whether the benefits provided to the market by DSM justify this cost. Questions about the role of DSM in the market have been raised before. In the 2008 Report to the Minister the Authority considered the participation of DSM in the RCM and recommended that alternative arrangements to govern the participation of DSM in the WEM should be considered as

[30] The actual value of Capacity Credits is determined by the prices paid for Capacity Credits under Bilateral Contracts.

part of the road map process. In the 2010 Report to the Minister, in response to comments regarding whether DSM provides capacity on an equivalent basis to generation, the Authority recommended that further investigations should be undertaken to more clearly assess the effectiveness of DSM in meeting the Market Objectives.

As part of the consultation process for this Report to the Minister, a number of stakeholders noted that there is excessive DSM in the market. Furthermore, some stakeholders suggested that, given that there is currently an excess of Capacity Credits in the WEM, the provision of Capacity Credits by proponents of DSM provides little benefit to the market. In particular, the question was raised as to whether the provision of Capacity Credits to DSM proponents is less worthwhile or effective than the provision of Capacity Credits to proponents of generation. To determine whether this is the case, it is important to consider the broader question of the costs and benefits of DSM.

In discussions with the Authority and in submissions to the Discussion Paper, a number of stakeholders commented that DSM receives the same capacity price as peaking generation, despite the fact, they contend, that it does not provide the same benefits to the market. In particular, a number of stakeholders noted that there are operational limitations on the dispatch of DSM[31] and restrictions on the number of hours that DSM can be dispatched during the year. One consequence of the restriction on the number of hours that DSM can be dispatched during the year is that the need to save these restricted hours for times in which DSM may be essential can result in DSM not being called upon at all. Stakeholders also questioned the extent to which the response of a DSM provider to an instruction to reduce load can be verified. In one view, the inability to verify the response of a DSM provider means that the market cannot verify the benefit provided by DSM. A number of stakeholders suggested that the implication of these restrictions is that DSM does not provide the same level of availability as generation, even peaking generation.

Reflecting these views on the costs and benefits of DSM, stakeholders provided a range of views on how they consider DSM should be treated. Broadly speaking these views can be divided into two categories:

- some stakeholders considered that the restrictions on the dispatch of DSM should be removed, bringing the benefits provided by DSM to the market in line with the benefits provided by other generators, and that DSM should continue to receive the same capacity payments as other forms of capacity; and
- other stakeholders considered that the restrictions on the dispatch of DSM should be retained and that the capacity payments made to DSM should be reduced to reflect these restrictions (reducing the costs to the market of capacity provided by DSM relative to the costs of capacity provided by generators).

In line with the view that restrictions on the dispatch of DSM should be removed, a number of stakeholders supported the general conclusions set out in the Lantau Group's report to the IMO on the RCM.[32] These conclusions were outlined by the Authority in its Discussion Paper. The Lantau Group recommended that the treatment of demand-side and supply-side resources in the RCM should be harmonised. According to the Lantau Group, this refinement could take a number of forms, including requiring all DSM to be available all hours of the year (like generators) or eliminating the 24 and 48 hour availability classes so that DSM would need to join a higher availability class. The Lantau Group also recommended that operational impediments to the dispatch of DSM (such as

[31] ERM submission, Synergy submission, System Management submission.

[32] Alinta submission, LGP submission.

notice periods and limitations on consecutive hours of DSM) should be eliminated to the extent that is possible.

Supporting the view that payments to DSM should reflect the dispatch restrictions that apply to DSM, a number of stakeholders suggested that the payment received by DSM should be changed to reflect the value provided by DSM.[33]

- ERM Power pointed to the model in place in the National Electricity Market (**NEM**), under which customers are incentivised to participate in DSM programs by receiving reductions in peak electricity prices. ERM Power suggest that this avoids the system-wide costs of DSM that occur under the RCM.
- Western Power suggested that a mechanism that pays different amounts per MW of capacity, to reflect how much dispatch notice DSM requires, how many hours DSM is available for each year, and DSM's cost, would seem to better reflect the value to the market of DSM capacity.
- Synergy suggested that having different payments for DSM is a better approach than requiring DSM to provide a similar level of availability to peaking generators. Requiring DSM and peaking generators to provide a similar level of availability would fail to reflect the fact that DSM can offer lower cost capacity than a peaking generator and that this can lower the overall cost of capacity to the market. One option suggested by Synergy to address this would be to offer DSM a lower fixed payment and a higher variable payment. Synergy considers that this would also provide better incentives to DSM to be available than the current mechanism (which involves a capacity payment with the possibility of refund payments if capacity is not available when called).
- The Sustainable Energy Association (**SEA**) suggested that if the treatment of DSM under the RCM is changed, then the capacity that is allocated to DSM should be based on the certainty and reliability with which that Curtailable Load will be available. SEA considers that this would be consistent with the treatment of intermittent renewable energy supplies.

The Authority has reviewed arrangements for DSM in other markets and found that it is more common for DSM to receive payments that reflect their dispatch restrictions than it is for DSM to be required to provide benefits to the market that are in line with the benefits provided by other generators. In energy-only markets, including the NEM and the New Zealand electricity market, DSM tends to be able to participate in the wholesale market by bidding to reduce demand. Under this approach, DSM can bid according to its availability i.e., there is no requirement for DSM to be available for a defined number of hours a year. Even in the PJM[34]market, which includes a capacity market, DSM is able to participate in the energy market by reducing demand without facing an obligation to be available for a defined number of hours a year. If a DSM provider participates on this basis, they do not receive a payment for providing capacity. A brief summary of arrangements for DSM in other markets is provided in Appendix 5.

Clearly, there are a range of potential arrangements by which DSM could participate in the WEM. The Authority considers that, given the increased participation of DSM in the WEM, and the costs associated with this, a review of the treatment of DSM in the WEM is timely. Indeed, the Authority notes that such a review is currently underway, with the IMO having recently established the RCMWG to address issues raised in the Lantau Group's report, including the role of DSM in the RCM.

[33] ERM submission, Western Power submission, Synergy submission.

[34] PJM Interconnected is a transmission organisation that coordinates the movement of electricity variously throughout 13 states in the District of Columbia. For more information see www.pjm.com.

Given the range of views expressed by stakeholders on the treatment of DSM, and the complexity of the issues involved, the Authority supports a detailed consideration of the treatment of DSM in the WEM, by the RCMWG.

Additionally, the Authority makes two recommendations in regard to this review by the RCMWG.

Firstly, the Authority considers that there is a need for policy direction into any decision regarding the treatment of DSM. Clearly, the focus of the RCMWG will be on promoting the Market Objectives, including promoting efficient production and supply of electricity and electricity related services. However, decisions about the treatment of DSM have the potential to significantly affect the commerciality of DSM within the WEM, and for this reason it is important to ensure that these decisions are consistent with the direction of broader energy policy.

Secondly, the Authority considers that the RCMWG should consider broadly the treatment of DSM in the WEM. The Authority understands that the starting point for the RCMWG's consideration of DSM in the WEM is the recommendation of the Lantau Group, that the treatment of DSM should be harmonised with the treatment of generation in the RCM by increasing the minimum availability requirement for DSM. However, as made clear by the Authority's review of arrangements for DSM in other jurisdictions, there are a range of options available aside from the Lantau Group's proposed approach.

The Authority's view is that there may be reasons to prefer an alternative model to that proposed by the Lantau Group, in particular, an approach under which the payment received by DSM is changed to reflect the value provided by DSM. The Authority considers that such an approach seems a more natural response to concerns about the capacity costs associated with DSM. The Authority considers that increasing the minimum availability requirement for DSM, as proposed by the Lantau Group, may deter DSM from participating in the market, which may not ultimately reduce the overall capacity cost to the market.

Alternatively, setting a lower capacity payment to DSM but maintaining the minimum availability requirement for DSM, may have the effect of lowering the overall capacity cost to the market and encouraging the continuous participation of DSM.

The Authority recognises that decisions about the treatment of DSM in the RCM, and the WEM more broadly, will ultimately need to be consistent with other outcomes from the RCMWG. This makes it difficult at this stage to assess the relative merits of alternative models for the treatment of DSM. However, the Authority considers that the RCMWG should carefully consider the merits of models adopted in other jurisdictions, including the option of changing the payment received by DSM to reflect the value provided by DSM.

Recommendation 1

Section 2.3

The treatment of Demand Side Management in the Wholesale Electricity Market should be reviewed by the Reserve Capacity Mechanism Working Group.

Given the materiality of this review, and reflecting the Authority's recommendations on the Rule Change Process, the Authority recommends that the Public Utilities Office should be involved in the working group and ensure that the outcomes of the working group are consistent with broader energy market policy.

The working group's consideration of the treatment of Demand Side Management should consider the merits of models adopted in other jurisdictions, including the option of changing the payment received by Demand Side Management to reflect the value provided by Demand Side Management.

2.4 Outage planning process

Planned Outages are outages of a generation facility (typically for maintenance work) that are approved by System Management. Once a request for an outage has been approved by System Management (and thereby becomes a Planned Outage) the facility is effectively permitted to be unavailable for the duration of the Planned Outage and will not be subject to any requirement to make payments for unavailability (meaning that it will effectively continue to receive its full capacity payments).

The Market Rules set out criteria that System Management must take into account in assessing whether to grant a request for a Planned Outage. These criteria are focused on system security, and specify that the remaining generation facilities must be able to meet forecast load, that the remaining generation facilities must be capable of meeting Ancillary Services Requirements, and that the remaining facilities must allow System Management to operate the power system within the required technical limits.

While System Management's assessment of whether to grant a request for a Planned Outage is rightly focused on system security, Planned Outages can also have a broader impact on market outcomes.

2.4.1 Price spikes during Planned Outages

In its Discussion Paper, the Authority noted that a number of STEM price spikes have coincided with Planned Outages. Furthermore, it was noted that the Secretariat's analysis of these events has raised concerns about the number of outage hours granted to certain generation facilities, particularly during high demand periods.

A number of stakeholders commented on the Authority's observation that price spikes have occurred during Planned Outages. Generally, stakeholders commented that the

STEM price spikes are a function of the operation of the market. That is, with significant capacity unavailable due to Planned Outages, it is to be expected that STEM prices would be higher and that, on occasion, STEM price spikes would occur.

However, some stakeholders commented that they consider that the price spikes are a result, at least in part, of the mix of generation plants that are granted Planned Outages. For instance, LGP questions the appropriateness of having large numbers of coal-fired plants on Planned Outages during the winter high demand period, and suggests that the outage planning process should make use of fuel diversity to avoid high price events. System Management noted that it does consider fuel types in its decisions on whether to grant applications for Planned Outages, but only in the context of constraints on generation that may occur due to the unavailability of fuel types, and the resulting potential for system security issues. System Management notes that the Market Rules do not explicitly require System Management to specify how fuel composition is taken into account in the outage planning process.

Whilst the Authority has concerns about some aspects of the current arrangements (as discussed further below), the Authority considers that it is appropriate to have System Management base its decisions on system security alone, and not on price. If System Management were to make outage planning decisions based on its views of the likely price impacts of outages, they would effectively put themselves into the position of central planner. In addition, under these arrangements, it is likely that there would be concerns about the transparency and independence of System Management's decisions.

2.4.2 Rates of Planned Outages

Planned Outages, even those that are approved by System Management, can have implications for price outcomes in the STEM and Balancing; with less plant generation capacity available to meet demand, prices are likely to be higher. The Authority is concerned that current rates of Planned Outages by some generation facilities in the WEM appear excessive.

The Authority's assessment of market outcomes includes an analysis of the extent to which facilities in the WEM are subject to Forced Outages and Planned Outages. As discussed in section 5.1.6, the Authority notes that the Planned Outage rates for some facilities in the WEM are extremely high and, in many cases, significantly higher than in previous Reserve Capacity Years. The Authority noted some higher Planned Outage rates, in particular at Verve Energy's facilities.

- Kwinana G5 (174 MW), which can be fired on coal, gas or oil, had a Planned Outage rate of 53.6 per cent;
- Kwinana G6 (174 MW), which can be fired on coal, gas or oil, had a Planned Outage rate of 49.6 per cent;
- Pinjar GT 11 (105 MW), which is an open cycle gas turbine (**OCGT**), had a Planned Outage rate of 49.3 per cent; and
- Muja G7 (211 MW), which is a coal-fired generation plant, had a Planned Outage rate of 42.7 per cent.

These Planned Outage rates can be compared to industry standard Planned Outage rates. One source for estimates of Planned Outages rates that could be considered to be the industry standard is data published in the Australian Energy Market Operator's (**AEMO**) National Transmission Network Development Plan. Among other things, AEMO report expected annual days of Planned Outages for generic coal plants, combined cycle gas turbine (**CCGT**) plants and OCGT plants. These expected annual days of Planned Outages equate to the following Planned Outage rates:

- for coal-fired generation plants, the expected Planned Outage rate varies from around 3 per cent to around 6 per cent;
- for CCGT plants, the expected Planned Outage rate varies from around 3.5 per cent to around 4.0 per cent; and
- for OCGT plants, the expected Planned Outage rates varies from around 1.5 per cent to around 6.5 per cent.

While generation facilities tend to have maintenance cycles that result in major maintenance works (and corresponding high Planned Outage rates) every few years, the Authority also notes that a number of generation facilities have had consistently high Planned Outage Rates. For instance, a number of Kwinana and Pinjar units have had consistently high Planned Outage rates for a number of consecutive years.

The Authority is concerned that these Planned Outage rates may be having a negative effect on outcomes in the WEM, particularly price outcomes in the STEM and Balancing Process. During periods when these facilities are unavailable other higher-cost generation facilities may be dispatched in order to meet energy demand, resulting in higher STEM and Balancing prices.

The Authority notes that there is a provision for monitoring Planned Outages under the RCM. As part of the Reserve Capacity Performance Monitoring requirements, the IMO must require Market Participants with a facility that has been unavailable due to Planned Outages for more than 1,000 hours (equivalent to 42 days or 12 per cent of a year) during the preceding 12 calendar months, to provide a report explaining these Planned Outages and setting out the expected maximum number of Planned Outages for the facility in the next 24 months. However, the Authority notes that these provisions are only triggered in circumstances in which SWIS-wide available capacity drops below a certain threshold level (i.e., 80 per cent during Hot Season and 70 per cent in either the Intermediate Season or Cold Season) for at least 40 days in any 12 month period. To date, there have been instances where the system availability threshold has been reached, however, the number of days were not as high as 40 over a 12 month period. Thus, the requirement for Market Participants with excessive Planned Outages to provide an explanatory report has not been triggered i.e., despite the poor availability of specific facilities. The Authority considers that the threshold for the IMO's monitoring of individual facility's availability level could be set too high and that this issue should be examined more fully.

More broadly, in an effective market, the Authority would expect that Market Participants would have incentives to have their facilities available to generate. In energy only markets, this incentive is driven by the fact that the spot market revenues that Market Participants earn depend upon the facility being dispatched in the spot market. In the WEM, the incentive to be available to generate is driven both by potential energy market revenues (through the STEM or Balancing) and revenues through the RCM. The RCM is relevant because the total revenues that generators receive for their capacity will depend on whether they are required to make Reserve Capacity Refund payments as a result of plant unavailability. For these reasons, the Authority considers that determining whether Market Participants have appropriate incentives to make their generation plant available depends on the incentives for availability that are driven by the RCM.

The Authority notes that the inter-relationship between the RCM and Reserve Capacity Refund payments was considered in the Lantau Group's report to the IMO on the RCM.[35]

[35] Alinta submission, LGP submission.

In particular, the Lantau Group raised the issue of whether a refund regime that linked refund payments to system conditions is appropriate. Currently, refund payments are unrelated to the scarcity of capacity at the time of an outage. The Lantau Group considered amending refund payments so that refund payments are higher if capacity is scarce at the time of an outage. Depending on details of implementation, this could increase incentives for availability at times when availability is more highly valued.

The Authority supports consideration of the inter-relationship between the RCM and Reserve Capacity Refund payments by the proposed RCM working group. The Authority considers that the issues to be addressed in the review should include questions of whether:

- the inter-relationship between the RCM and Reserve Capacity Refund payments provides appropriate incentives for availability?
- a refund regime that links refund payments to system conditions would improve incentives for availability?

2.4.3 Granting of Planned Outages

ERM notes in its submission, that the IMO's current interpretation of the Market Rules is such that a facility is not granted a Planned Outage unless the facility is available at the time the operator applies for the Planned Outage. In other words, if a generation facility is unavailable because of a plant breakdown, the operator cannot apply for a Planned Outage until the operator first resolves the issue causing the breakdown and returns the facility to service.

ERM considers that the current arrangements are inappropriate and that the relevant consideration should be the effect of granting a Planned Outage on system security i.e., whether the facility is available when it applies for a Planned Outage should be irrelevant. ERM considers that the current arrangements create incentives for generators to perform poor quality equipment repairs in order to quickly return the plant to services (and perhaps, apply for a Planned Outage to undertake more substantial work). This may ultimately lower system reliability.

The Authority agrees that, insofar as system security is concerned, whether a facility is available when it applies for a Planned Outage is not directly relevant. What matters for system security is the extent of the outage, the timing of the outage, and the broader market conditions (including the availability of other generators) at the time of the outage. However, there may be other reasons to prevent a facility that is unavailable from applying for a Planned Outage. For instance, granting a Planned Outage to a facility that is unavailable will likely have implications for the Reserve Capacity refund mechanism.[36] A facility that is granted a Planned Outage will not face any financial penalties for being unavailable under the Reserve Capacity refund mechanism. Granting a Planned Outage to a facility that is already unavailable could therefore have the effect of lessening the incentives created by the Reserve Capacity refund mechanism. For this reason, the appropriateness of granting Planned Outages to facilities that are unavailable at the time of application should be considered as part of the review of the RCM, as discussed in Section 2.4.3.

ERM agrees with this view, noting that there is a clear link between the outage planning process and the RCM, and that a review of the outage planning process should only be

[36] Under the Market Rules, if a Market Participant holding Capacity Credits associated with a generation system fails to satisfy its Reserve Capacity Obligations, then it must pay a refund to the IMO. See Clause 4.26.1 of the Market Rules for information on how this refund is calculated.

undertaken in conjunction with a broader review of the Reserve Capacity Refund Mechanism.

Recommendation 2

Section 2.4

The incentives for plant availability created by the inter-relationship between the Reserve Capacity Mechanism and Reserve Capacity Refund payments should be reviewed by the Reserve Capacity Mechanism Working Group.

Specifically, the working group should consider whether the design of the Reserve Capacity Mechanism provides appropriate incentives for plant availability and whether a refund regime that links refund payments to system conditions would improve incentives for availability.

2.5 Climate change policies

In the 2010 Report to the Minister, the Authority discussed at length the existing renewable energy incentive schemes, in order to gauge the impact that they may be having on the WEM. The Authority concluded that:

- the federal and state renewable energy incentive schemes are an expensive, economically inefficient means to achieve the policy objective of greenhouse gas abatement; and
- in comparison, a mechanism for pricing carbon would promote efficient investment and provide for a better transition from fossil fuel to low carbon generation technologies.

The Productivity Commission's review *Carbon Emissions Policies in Key Economies*[37] came to a similar view. This report examined the relative cost of a number of Australia's existing greenhouse policies, including the Large-Scale Renewable Energy Target (**LRET**), the Small-Scale Renewable Energy Scheme (**SRES**) and feed-in tariffs. Based on this analysis, the Productivity Commission concluded that the emissions abatement achieved by these policies is far more expensive than the emissions abatement that would be achieved by an explicit carbon price. Specifically, the Productivity Commission concluded that, for the aggregate cost of the LRET, SRES and feed-in tariffs, more than twice the abatement could be achieved through an explicit carbon price. The Productivity Commission also noted that a carbon price in combination with other measures will generally be less cost effective than one operating on its own.

In subsequent discussions with the Authority and in submissions to the Discussion Paper, a number of stakeholders reiterated these points, commenting that the renewable energy policies, such as the LRET and the SRES, are an inefficient way to achieve abatement of greenhouse gas emissions. Other stakeholders, however, commented on the broader benefits of renewable energy. For instance, the SEA considers that the Authority's conclusions in the 2010 Report to the Minister regarding the inefficiencies of current

[37] Productivity Commission, *Carbon Emissions Policies in Key Economies*, Research Report, May 2011.

renewable energy schemes are incorrect. In particular, SEA considers that there are a number of benefits of renewable energy, beside carbon abatement.

Regardless of the evidence that a carbon price is a lower cost option for achieving emissions abatement than other renewable energy policies, it is now clear that Market Participants in the WEM will be subject to both a carbon price and renewable energy incentive schemes. Given that legislation to introduce a carbon price has now passed, and a carbon price will be in place from 1 July 2012, the Authority considers that it is useful to consider the likely effect of a carbon price on the WEM. Because the carbon price and the renewable energy incentive scheme will create incentives and outcomes that interact, it is important to consider both policies together.

A useful starting point is the Australian Energy Market Commission's (**AEMC**) *Review of Energy Market Frameworks in light of Climate Change*.[38] As part of this review, the AEMC retained Frontier Economics to advise on the direct and consequential effects of climate change policies on the Western Australian energy market.[39] Frontier Economics found that:

- because the price of gas is higher in Western Australia than it is in the NEM, it is unlikely that fuel shifting will occur in Western Australia to the same degree as in the NEM;
- to the extent that regulated tariffs in Western Australia remain below cost-reflective levels, the introduction of a carbon price will increase the gap between retail tariffs and costs of supply, putting the financial viability of retailers at risk and discouraging the development of competition in the retailing sector; and
- there is the potential for significant issues as a result of the renewable energy target, including in relation to dispatch of scheduled generators, Verve Energy's exposure to balancing, the treatment of wind generation in the RCM, Ancillary Services costs and network connections.

Subsequently, the AEMC retained Energy Market Consulting associates (**EMCa**) to advise on network-related market issues in Western Australia. EMCa identified a number of network-related market issues relevant to the introduction of climate change policies, and recommended a number of measures to improve the connection process, including a change to the unconstrained planning policy, improved market information on network access, and modifications to the queuing policies and procedures.

Reflecting these broad issues, the following sections consider in further detail:

- the impact of a carbon price on generation outcomes in the WEM;
- the impact of a carbon price on retail outcomes in the WEM;
- the impact of intermittent generation on the WEM; and
- network connection issues.

[38] See AEMC website, Review of Energy Market Frameworks in light of Climate Change Policies web page, http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-Energy-Market-Frameworks-in-light-of-Climate-Change-Policies.html

[39] See AEMC website, Frontier Economics, *Review of implications for energy markets from climate change policies – Western Australian and Northern Territory elements*, A report prepared for the Australian Energy Market Commission - November 2008, http://www.aemc.gov.au/Media/docs/Frontier Economics - Impacts of CPRS and RET on WA and NT energy markets - Final Report - Public Version-92840561-fb9b-4e4a-bbe1-e52839f17b25-0.pdf

2.5.1 Impact of a carbon price on generation outcomes in the WEM

The intention of the carbon price is to make generators face the costs associated with the greenhouse gas emissions that they produce. The effect of this is to make high-emitting generation plants more expensive and low-emitting generation plants less expensive. In a competitive market, this will ultimately result in changed patterns of energy output i.e., there will be relatively less output from high-emitting generation plants and relatively more output from low-emitting generation plants. In the long-term the carbon price will also change investment decisions in favour of low-emitting generation plants. Ultimately, these changes to the patterns of output and investment will change the nature of the electricity market.

In order for an electricity market to respond efficiently to the introduction of a carbon price, it is necessary for generators to be able to reflect the carbon price in their offers to supply energy. The Authority does not see this as being an issue in the WEM.

The Energy Price Limits (**EPL**) that are applicable for energy trading in the WEM will take into account the carbon price and the emissions intensity of the relevant generation plant. In this way, generators will be able to recover their relevant short run marginal cost (**SRMC**) with the introduction of a carbon price. The Authority notes that the IMO is currently in the process of reviewing the EPL to account for the carbon price.

The Authority also expects that the carbon price will be reflected in the prices of bilateral contracts negotiated between generators and retailers. While some existing bilateral contracts may not provide for the pass-through of carbon costs, the Authority expects that the carbon price pass-through would have been included in more recent bilateral contracts, and will be included in future bilateral contracts.

Generally speaking, stakeholder comments also supported this view: suggesting that the design of the WEM will be robust enough to accommodate the introduction of a carbon price. For instance, Synergy commented that the carbon price is expected to be reflected in variable costs and, ultimately, prices in the market.

2.5.2 Impact of a carbon price on retail outcomes in the WEM

In order for energy markets to respond efficiently to the introduction of a carbon price, it is important for the carbon price to be reflected in both wholesale energy costs and retail energy costs. In its draft report for the inquiry into the efficiency of Synergy's costs and electricity tariffs, the Authority has estimated that the Federal Government's carbon pricing scheme will result in a price increase of 8.2 per cent in the regulated tariffs across all customer groups in 2012/13.[40]

In previous Reports to the Minister, the Authority has consistently recommended that regulated retail tariffs should be set at cost-reflective levels. Stakeholders have also been supportive of this view, even in discussions prior to the production of this Report to the Minister. The Authority considers that the introduction of a price on carbon further highlights the importance of setting regulated retail tariffs at cost-reflective levels. If regulated retail tariffs fail to reflect the carbon price, then the incentives for retail customers to respond to the introduction of a carbon price will be muted. In addition, there will be an ongoing requirement for funding of subsidised regulated retail tariffs, and a likely delay to the introduction of full retail contestability (given that the effectiveness of

[40] See ERA website.

full retail contestability depends on having regulated retail tariffs set at cost-reflective levels).

2.5.3 Impact of intermittent renewable generation in the WEM

While the Authority is confident that the design of the WEM will be able to accommodate the introduction of a carbon price scheme, there are potential issues arising in the market as a result of the increase in intermittent generation driven by renewable energy policies.

A number of stakeholders have raised specific issues about the effects of intermittent renewable generation on the WEM. For instance, Synergy considers that, under current arrangements, an increase in intermittent generation in the WEM:

- could threaten the economic dispatch of base-load generation at low demand times (particularly overnight);
- may increase the use of low efficiency gas turbines to maintain frequency control at low demand times (particularly overnight); and
- may increase the cost of Load Following Ancillary Services (**LFAS**).

These issues have been the subject of ongoing reviews in the WEM.

Firstly, in relation to the economic dispatch of base-load generation, the Authority recognises that increased renewable generation could threaten the economic dispatch of base-load generation. Specifically, because renewable generation is able to supply power at a very low marginal cost (even a negative marginal cost, because it effectively receives a subsidy to generate) it can displace base-load generation in the dispatch merit order. This means that base-load generators may be forced towards their minimum stable generation levels overnight, when demand is low. This may lead to inefficient overnight shutdowns and consequent restarting costs and delays that may compromise efficiency and next-day system reliability. Indeed, the Authority notes that certain Verve Energy base-load facilities are at times being shutdown overnight and on weekends. The Authority considers that the introduction of a competitive Balancing market from July 2012 should deliver better outcomes with regard to economically efficient dispatch of generation facilities as both Verve Energy and IPPs will be able to compete for the provision of the Balancing service, particularly during low demand times.

Secondly, in relation to the increased use of low efficiency gas turbines and the increasing costs of LFAS, the new competitive LFAS market from July 2012 should also contribute towards more efficient outcomes. The Authority is aware that the IMO has been working on a methodology for allocating the costs of LFAS on a causer-pays basis. The IMO noted that the implementation of this methodology would depend on the introduction of the LFAS market. Now that work on the introduction of the LFAS market is substantially developed, in advance of the 1 July 2012 commencement date of that market, the IMO expects to be able to progress the methodology for allocating the costs of LFAS.

2.5.4 Network connection issues

Western Power noted in its submission that the AEMC's review of the impact of climate change policies in the WEM made a number of recommendations in regard to network connection and planning issues (which were discussed in some detail in previous Reports to the Minister). Given that climate change policies are expected to continue to drive incentives for new generation investment (particularly for renewable generation) effective network connection and planning is important for supporting these policies.

Western Power commented that work to address many of the areas for improvement identified by the AEMC is either underway or has been proposed. This includes improving market information, modifying Western Power's queuing policy for transmission access applications, and relaxing the unconstrained network access arrangements in the SWIS.

The Authority notes that some steps have been undertaken since the AEMC review. For instance, greater information on network capacity and network expansions has been released by Western Power through the Network Capacity Mapping Tool.[41] This tool provides information that includes forecast substation capacity, potential network connection points for generators, and distribution and transmission network projects that have been approved for future development.

However, to a large extent, the issues identified by the AEMC remain under review, particularly as part of the Directions Paper undertaken by the Office of Energy. Some of the major issues identified by the AEMC have been raised in the Directions Paper for the Strategic Energy Initiative and the third Access Arrangement proposed by Western Power. These include the unconstrained network access arrangements in the SWIS, the framework for network planning, and Western Power's queuing policy for transmission access applications. The Authority discusses the need for policy direction in more detail in Section 2.6.2, but reiterates the importance of finalising the Strategic Energy Initiative in order to confirm the policy direction for these network issues.

Some stakeholders commented that there are still substantial issues with the performance of Western Power in their provision of network connections to new generators. However, concern among stakeholders about network connection issues seems to have moderated relative to that expressed by stakeholders during consultation for previous Reports to the Minister. The Authority will continue to canvass stakeholder concerns as part of future Reports to the Minister.

2.6 Market governance

2.6.1 The Independent Market Operator's role in the Market Rules change process

In discussions with the Authority and in submissions to the Discussion Paper, a number of stakeholders raised concerns about the IMO's dual role in determining whether to approve amendments to the Market Rules, and in administering the Market Rules.

This issue has been raised by stakeholders in one way or another since the Authority undertook its first Report to the Minister. In previous Reports to the Minister, the Authority concluded that the IMO should remain responsible for administering the Rule Change Process, but the Authority noted that it would continue to assess whether the existing arrangements are likely to impact on the effectiveness of the market. In coming to this view, the Authority was mindful of the relatively small size of the WEM and the risk that economies of scope would be lost if some of the IMO's roles were either allocated to a new entity or allocated to a ring-fenced division within the IMO.

While recognising that the IMO's role in the Rule Change Process has been an issue raised by stakeholders since market commencement, based on recent discussions with stakeholders and submissions to the Discussion Paper, the Authority considers that stakeholders' concerns about the IMO's role have recently increased. While a number of stakeholders raised specific issues with individual Rule Change Proposals, the principal

[41] See Western Power web site: http://www.westernpower.com.au/ldd/ncmtoverview.html

concern of stakeholders relates more broadly to the governance arrangements. In particular, a number of stakeholders pointed out that there is the potential for a conflict of interest to arise as a result of the IMO's dual role in determining whether to approve amendments to the Market Rules and in administering the Market Rules (including enforcing the Market Rules). According to a number of stakeholders, these existing governance arrangements could result in inappropriate decisions on Rule Change Proposals that affect the IMO.

It is important to point out that stakeholders did not suggest that the IMO's decisions have been influenced by any conflict of interest. Indeed, a number of stakeholders commented that the IMO had handled the potential issues well, and that the arrangements to date have been appropriate. Also, the IMO noted that the vast majority of Rule Change Proposals that have been approved have had the majority support of the Market Advisory Committee (**MAC**). Nevertheless, a common view was that the existing governance arrangements are not ideal, and that there is merit in now considering revisiting these arrangements.

Insofar as governance arrangements are concerned, the Authority considers that the perceptions of Market Participants, and potential future Market Participants, are crucial. If participants have concerns that there are issues with the governance arrangements that could result in outcomes from the Rule Change Process failing to promote the Market Objectives, then this will likely increase concerns about regulatory risk among investors. Given that the Rule Change Process is increasingly dealing with market design issues that have the potential to substantially affect commercial outcomes for Market Participants, the Authority considers that confidence in the governance arrangements among Market Participants is becoming increasingly important.

The Authority also notes that the Commonwealth Government's Draft Energy White Paper concluded that there would be merit in considering further separation between the rule maker and the market operator roles in the WEM, to ensure that optimal outcomes for consumers are being achieved.[42]

Because of the increasing concern among Market Participants, and because an effective Rule Change Process is crucial at a time of market evolution, the Authority considers that a review of the market governance arrangements in the WEM, and particularly the appropriateness of the IMO's role in the Rule Change Process, is timely and important. The Authority notes that a number of stakeholders have pointed to the governance arrangements in the NEM in which an independent body, i.e., the AEMC, is responsible for making changes to the market rules. However, the Authority would be wary of simply adopting the governance model that applies in the NEM, as what is appropriate in the NEM may not be appropriate in the WEM. In particular, given that the WEM is substantially smaller than the NEM, it may be the case that different governance arrangements are appropriate. The benefits of an independent body responsible for market changes to the Market Rules in the WEM may not outweigh the costs.

The Authority understands that that there are a range of governance arrangements operating in other markets. A brief summary of arrangements in some key markets is provided in Appendix 6. In regard to the Rule Change Process, this summary reveals that a number of other markets do not have independent entities that have responsibility for assessing rule changes. In some markets the entity responsible for economic regulation is also responsible for rule changes, while in other markets the entity responsible for rule changes also plays a role in market operation. Indeed, the governance arrangements in the NEM, which incorporate separation of all the major governance functions, are

[42] Draft Energy White Paper 2011: Strengthening the foundations for Australia's energy future, page 133.

uncommon, even in markets much larger than the WEM. Similarly, in regard to market operation and system operation, this summary reveals that there are a range of different arrangements in other markets. The NEM model, in which AEMO is market and system operator, is by no means, universal.

Based on this review, the Authority notes that there are a number of potential alternatives for governance arrangements in the WEM, each with separate costs and benefits.

- **An independent entity takes responsibility for the Rule Change Process**. Under this approach, a new independent entity would need to be constituted, and take over responsibility for the Rule Change Process. The new entity would require a decision making body, as well as staff to support the decision making process. The costs associated with funding the work of this independent entity would need to be borne by Market Participants (and ultimately by end consumers). These costs would likely be larger than for the existing arrangements or the other alternatives (given that there would be, by design, no opportunity for economies of scope between the assessment of Rule Change Proposals and other WEM-related activities). Against this, the benefit of greater certainty as to the independence of the governance arrangements would be highest with an independent entity taking responsibility for the Rule Change Process. Since this independent entity would have no role beyond the Rule Change Process, there could be little genuine concern about the potential for conflicts of interest.
- **A ring-fenced entity within the IMO takes responsibility for the Rule Change Process**. Under this approach, the IMO would remain responsible for the Rule Change Process, but there would be greater separation between the IMO's role in the Rule Change Process and its other functions. In the interests of greater certainty as to the independence of the governance arrangements, the priority would be to separate the decision making body from the IMO. In this regard, one option would be to transfer this responsibility from the IMO Board to a new committee with broader representatives, potentially including representatives from Government, the Authority and Market Participants. Ring-fencing the staff that support the decision making process would likely be a lower priority. Again, there would be some additional costs under this arrangement, although it would be expected that these would be lower than the costs of constituting a new independent entity. While this option would be expected to reduce concern about conflicts of interest, the ongoing role of IMO staff in the Rule Change Process may result in some residual concern about conflicts of interest.
- **The Authority takes responsibility for the Rule Change Process**. Under this approach the Authority would assume responsibility for the Rule Change Process, with the Authority's Governing Body being the decision making body, and the Authority staff supporting the decision making process. The costs of this approach would presumably be similar to the costs of the existing arrangements i.e., there would be no need to constitute a new entity and presumably no net increase in the number of staff required to support the decision making process. However, it might be considered that there is little benefit to this approach because, whilst the IMO would no longer have a conflict of interest in administering the Rule Change Process, the Authority would now have a conflict of interest. Nonetheless, given that the ERA has a much smaller role in the market than the IMO, it would be expected that the potential for conflicts to arise would be diminished.

It is the Authority's view that the review of the market governance arrangements should assess, in detail, the costs and benefits of these options, relative to the existing arrangements. Additionally, other issues to be addressed in deciding upon the appropriate governance arrangements in the WEM should include questions of whether:

- there is sufficient resource base among the relevant agencies to take on separation of all the major governance functions?
- there are options other than the separation of all the major governance functions that would address the concerns among Market Participants about the existing arrangements? Here, in particular, consideration should be given to how, in other markets without independent entities responsible for rule changes, concerns about conflicts of interest are addressed and whether stakeholders are satisfied with these arrangements.

Whilst the Authority considers that addressing the Rule Change Process is the most pressing market governance issue, it can also see a benefit in the review of market governance arrangements considering broader issues. One such issue is whether there is merit in moving System Management out of Western Power. This issue was raised in previous Reports to the Minister, at which point System Management highlighted the significant costs and informational disadvantages that would arise if this option were pursued. System Management considered that these costs were not justified given the small size of the SWIS. However, given that the market has now further developed, the Authority considers that it would be worthwhile revisiting this issue.

Recommendation 3

Section 2.6

The existing governance arrangements in the Wholesale Energy Market should be reviewed to determine whether the existing arrangements remain appropriate for the ongoing development of the market. The review should be undertaken by the Public Utilities Office, with input from all stakeholders.

2.6.2 The need for policy guidance

Another concern, related to the role of the IMO in the Rule Change Process, is the role of broader policy guidance in the ongoing evolution of the market, and how this relates to the Rule Change Process.

A number of stakeholders have noted that Rule Change Proposals have more recently begun to deal with matters that go to the fundamental design of the WEM, including the introduction of competitive Balancing and LFAS. Some stakeholders questioned whether the current rule change arrangements are suitable for managing these matters. In particular, stakeholders questioned whether the current Rule Change Process is sufficiently broad to weigh up the economic and social policy objectives of significant changes to the design of the market.

A common view was that decisions about matters that go to the fundamental design of the WEM would benefit from policy input. Stakeholders have consistently put forward their view in both industry forums and directly to the Authority that, at the very least, it is important that any decisions about the re-design of the WEM should be consistent with the broader energy market reform agenda in Western Australia. A number of stakeholders commented that there is a lack of policy direction coming from the Government, partly as a result of the apparent lack of progress on the Strategic Energy Initiative. The Authority understands that the final documents relating to the Strategic Energy Initiative were due to be released in mid-2011 but have not yet been made publicly available.

A number of stakeholders commented, stating that the Office of Energy should be more involved in decisions about the re-design of the WEM, including decisions about the introduction of competitive Balancing and LFAS, and any amendments to the Market Rules relating to DSM and intermittent generation. More broadly, a number of stakeholders indicated that there is a lack of clear policy direction from the Government on important issues, such as the proposed merger of Verve Energy and Synergy, the supply of fuel to the WEM, the transition to cost-reflective tariffs, and the introduction of full retail contestability. The Authority also notes that the Commonwealth Government's Draft Energy White Paper identified retail price deregulation, the introduction of full retail contestability, and addressing issues created by Government ownership, among the key energy market reform areas that need to be completed.[43]

In previous Reports to the Minister, the Authority has highlighted the need for a process to be put in place to lay out a strategy for the future development of the WEM. Given that the ongoing evolution of the market will need to reflect broader policy decisions, the Authority recommended that this work should be guided by the Office of Energy. As it has happened, the Authority considers that there has been little clear direction provided by the Office of Energy to date. The IMO has been largely responsible for driving the evolution of the WEM, in particular through the work of the Market Evolution Program (**MEP**) and the subsequent Rules Development and Implementation Working Group (**RDIWG**),[44] which has been responsible for the introduction of competitive Balancing and LFAS. On broader policy matters, however, Market Participants remain uncertain about the direction of future reforms.

The Authority considers that this situation is not consistent with the ongoing development of an efficient market. Based on discussions with stakeholders, the Authority considers that stakeholders are increasingly concerned about regulatory risk in the market. A large part of this is due to uncertainty about policy decisions regarding the future development of the market, including fundamental decisions such as the potential merger of Verve Energy and Synergy. Faced with this policy uncertainty, timely private sector investment is at risk.

The Authority considers that the Public Utilities Office (previously the Office of Energy) is best placed to provide clarity on policy regarding the future development of the market. The Authority notes that the Strategic Energy Initiative, commenced by the Office of Energy, is intended, among other things, to develop a set of clear goals to guide decisions by policy makers and investors and to develop a policy and regulatory framework to promote investment and competitiveness. It is the Authority's view that the achievement of effective outcomes in the WEM requires this clarification of the future policy direction

[43] Draft Energy White Paper 2011: Strengthening the foundations for Australia's energy future, page 133.

[44] The RDIWG is tasked with assessing the design issues/problem areas derived from: the Market Rules Evolution Plan; and issues identified as part of the Verve Energy Review. The RDIWG first met in August 2010. Further information on the RDIWG is available on the IMO's website, Rules Development Implementation Working Group web page, http://www.imowa.com.au/n139.html

from Government. As a first step, the Authority encourages the Government to finalise the Strategic Energy Initiative and provide clear policy direction.[45]

In addition, the Authority considers that there would be a great benefit to be gained from the Public Utilities Office being more visibly engaged in scoping out the direction of future Rule Change Proposals that are fundamental to the design of the market. To be clear, the Authority is not recommending that the Public Utilities Office should be responsible for administering the Rule Change Process. Rather, the Public Utilities Office should keep the MAC and Market Participants more broadly informed of whether Rule Change Proposals that are fundamental to the design of the market are consistent with broader energy market policy.

Finding 2

Section 2.6

Achieving effective outcomes in the Wholesale Electricity Market requires clear guidance on the future policy direction from Government. This policy direction needs to be provided through the finalisation of the Strategic Energy Initiative, and thereafter on an ongoing basis.

2.6.3 Transparency of Market Rules change process

Some stakeholders raised issues related to the transparency of the Rule Change Process.

For instance, some stakeholders commented that there have been a number of occasions when the MAC has not been provided with the full details of reviews or assessments of proposed rule changes undertaken by consultants to the IMO.

System Management suggested that there should be improved disclosure and transparency of the MAC proceedings, including reporting of whether individual MAC members have supported or rejected a particular proposal.

As a general proposition, the Authority recommends that the consideration of Rule Change Proposals should be as transparent as possible. There may be occasions when issues of confidentiality, or other commercial sensitivities, prevent complete transparency. However, the Authority would expect occasions such as these to be the exception.

[45] The Authority also notes that the Commonwealth Government's Draft Energy White Paper identified the Strategic Energy Initiative as important to the progress of reform in Western Australia's electricity market. Draft Energy White Paper 2011: Strengthening the foundations for Australia's energy future, page 133.

Recommendation 4

Section 2.6

The review of existing governance arrangements in the Wholesale Energy Market should recommend policies to govern the transparency of information and material related to the consideration of Rule Change Proposals.

2.6.4 Market Procedures

In discussions with the Authority and in submissions to the Discussion Paper, Synergy commented that the Rule Change Proposal to introduce competitive Balancing and LFAS, reflects a change in the drafting philosophy of the Market Rules. More of the detail of the competitive Balancing and LFAS arrangements is to be contained in the Market Procedures, with the Market Rules limited to providing higher-level principles. This will result in the Market Procedures playing a more important role in the market.

This raises some potential issues with regard to the governance arrangements in the WEM. Firstly, only the IMO or System Management can submit Procedure Change Proposals. Consequently, as the Market Procedures become more important to the operation of the market, the ability of stakeholders to independently propose changes to the operation of the market is diminished. Secondly, the Procedure Change Process differs from the Rule Change Process. As the Market Procedures become more important to the operation of the market, less of the changes to the operation of the market will be reviewed under the Rule Change Process.

Recommendation 5

Section 2.6.4

The review of existing governance arrangements in the Wholesale Energy Market should determine whether the existing arrangements for both rule changes and procedure changes remain appropriate for the ongoing development of the market.

2.6.5 Requirements for Rule Change Proposals

In discussions with the Authority and in submissions to the Discussion Paper, Alinta commented that the Market Rules and associated processes do not place sufficient obligation on submitters of Rule Change Proposals to clearly articulate the issue being addressed, or the intended outcome. In addition, the Market Rules do not require empirical evidence to support the view that the Rule Change Proposal will achieve the intended outcome.

The Authority accepts that the existing arrangements, particularly the absence of any obligation on submitters of Rule Change Proposals to provide empirical evidence, may result in some Rule Change Proposals being submitted that are found to be lacking in merit. However, the Authority is concerned that imposing stricter obligations on the submission of Rule Change Proposals may effectively prevent less sophisticated Market Participants from being in a position to submit legitimate Rule Change Proposals. This issue is ultimately related to resourcing issues created by the number of Rule Change Proposals over the last year or two and, as discussed below, the Authority will continue to canvass stakeholder concerns on this, as part of future Reports to the Minister.

2.6.6 Resourcing

Some stakeholders commented, suggesting that the number of Rule Change Proposals in recent times (particularly complex Rule Change Proposals), have posed resourcing problems for Rule Participants; if not for the IMO, certainly for other Market Participants.

The Authority notes that stakeholders that raised concerns about resourcing problems generally raised the issue in the context of the detailed Rule Change Proposal that has emerged from the MEP process. Stakeholders do not appear to be concerned about the resourcing required more generally. For this reason, the Authority considers that this is likely to be a temporary issue due to the introduction of competitive balancing and LFAS. However, the Authority will continue to canvass stakeholder concerns as part of future Reports to the Minister.

PART B

3 Monitoring the effectiveness of the Wholesale Electricity Market

Clause 2.16.11 of the Market Rules requires that the Report to the Minister provides an assessment on the effectiveness of the market in dealing with matters identified in clauses 2.16.9 and 2.16.10 of the Market Rules. This chapter addresses the Authority's reporting requirements under clause 2.16.9.

Under clause 2.16.9 of the Market Rules the Authority is responsible for monitoring the effectiveness of the market in meeting the Market Objectives, and that the Authority must investigate any market behaviour that has resulted in the market not functioning effectively. The Authority, with the assistance of the IMO, must monitor:

- Ancillary Services Contracts and Balancing Support Contracts;
- instances of inappropriate and anomalous market behaviour (in relation to bidding in the STEM and Balancing, as well as in the making of Availability Declarations, Ancillary Services Declarations and Fuel Declarations);
- market design problems or inefficiencies; and
- problems with the structure of the market.

This section sets out a summary of the Authority's assessment on the effectiveness of the market in dealing with matters identified in clause 2.16.9 of the Market Rules and is structured as follows:

- Section 3.1 reports on Ancillary Services Contracts and Balancing Support Contracts;
- Section 3.2 reports on inappropriate and anomalous market behaviour;
- Section 3.3 reports on market design problems or inefficiencies; and
- Section 3.4 reports on problems with the structure of the market.

3.1 Ancillary Services Contracts and Balancing Support Contracts

3.1.1 Ancillary Services Contracts

In the WEM, Ancillary Services are required to maintain power system security and reliability through the control of key technical characteristics, such as frequency and voltage, which ensures that electricity supplies are of acceptable quality. There are five defined types of Ancillary Services applicable in the SWIS, which are Spinning Reserve, Load Following, System Restart, Load Rejection Reserve and Dispatch Support.[46]

System Management is required to source Ancillary Services, either from Verve Energy (the default provider) or from IPPs, on a least cost basis. System Management is also required to estimate the technical requirements for Ancillary Services, based upon standards set out in the Market Rules. The IMO recovers the costs of the Ancillary Services from Market Participants through the market settlement process.

[46] These Ancillary Services are defined in section 3.9 of the Market Rules, and are also described on the IMO's website, Types of Ancillary Services web page, http://www.imowa.com.au/ancillary-services-types

At present, there are only limited opportunities for IPP's to source revenue streams from providing Ancillary Services.

System Restart Ancillary Services had been provided only by Verve Energy under a contractual arrangement organised by the State Government prior to the commencement of the WEM. The arrangement expired on 30 June 2011. System Management had undertaken a competitive tender process for procuring the service required in three sub-networks. System Management successfully negotiated two five-year service contracts for services required in two sub-networks. Both contracts commenced on 1 July 2011. System Management directly negotiated a fee for service for the third sub-network for a two year term from 1 July 2011 because no offers were received for this sub-network.[47]

Payments for these contracts are collected via the R value of the Cost_LR parameter[48] defined in the Market Rules. Under clause 3.13.3C of the Market Rules, the Authority is responsible for determining the Cost_LR parameter. The Authority published its decision on the revised Cost_LR parameter for the 2011/12 and 2012/13 financial years proposed by System Management on 20 April 2011. The R values determined by the Authority are $491,200 per annum in 2011/12 and $499,000 per annum in 2012/13. In its decision paper, the Authority stated its view that these values should be sufficient to cover the costs of the three contractual arrangements negotiated by System Management in meeting the System Restart Ancillary Services requirements in the SWIS for the 2011/12 and 2012/13 financial years.

System Management has not activated the Load Rejection Reserve Ancillary Service since the commencement of the market. This is reflected in the L value of the Cost_LR parameter, which has been set at nil.

Verve Energy has been the default provider of Spinning Reserve Ancillary Service since market commencement. Verve Energy receives a payment from the market which is calculated based on the Balancing price (i.e., the Marginal Cost Administered Price (**MCAP**)) multiplied by a margin value determined by the Authority under the Market Rules. On 31 March 2011, the Authority published its decision on the margin values for the 2011/12 financial year as 25 per cent for Margin_Peak and 43 per cent for Margin_Off-Peak.[49] The requirement for Spinning Reserve Ancillary Service is determined by System Management to be 70 per cent of the largest output of any Facility on the system. During 2011/12 Collie Power Station is the largest Facility on the SWIS with a maximum generated output of 340MW.[50] Hence, the maximum Spinning Reserve level that may be required during 2011/12 is 240MW. Spinning Reserve can be provided by either synchronised generation or Interruptible Loads. At the start of the 2011/12 financial year, 52MW of Spinning Reserve Ancillary Service was provided by Interruptible Load supplied by two non-Verve Energy Market Participants. This reduced to 42MW in October 2011

[47] See ERA website, Determination of Ancillary Service Cost_LR parameter - April 2011, http://www.erawa.com.au/cproot/9514/2/20110420 Decision- Determination of the Ancillary Service Cost_LR parameter.pdf

[48] The Cost_LR parameter covers the payment to a Market Generator for the costs of providing the Load Rejection Reserve and System Restart Ancillary Services, and specific Dispatch Support Ancillary Service.

[49] See ERA web site, Determination of Ancillary Service Margin Peak and Margin Off-Peak Parameters for the 2011/12 Financial Year – March 2011, http://www.erawa.com.au/cproot/9479/2/20110331 Determination of the Ancillary Service Margin_Peak and Margin_Off-Peak Parameters.pdf

[50] However, the Facility with the highest registered capacity is Newgen Neerabup with 342 MW, but this is made up of two generating units of 171MW each.

after the contract to supply 10MW from one supplier expired. The remaining Spinning Reserve will be supplied by synchronising additional Verve Energy generators.[51]

The current Deed of Undertaking between System Management and Verve Energy for the provision of Dispatch Support Ancillary Services in the Eastern Goldfields and North Country (Mungarra and Geraldton) regions was approved by the Authority on 23 April 2008. Verve Energy's facilities at Mungarra, West Kalgoorlie and Geraldton are nominated to supply these Dispatch Support Ancillary Services. This current deed is due to terminate upon commissioning of the 330kV transmission line from Perth to the North Country region. System Management has not indicated its intention to enter into other arrangements for dispatch support.[52]

Regarding LFAS, since market commencement System Management has worked towards competitively procuring LFAS from IPPs but this has not resulted in the service being contracted.[53] The proposed competitive LFAS market that is expected to commence operation in July 2012 will provide an opportunity for IPP's to decide whether to compete in the provision of this service. In the 2010 Report to the Minister, the Authority noted its support for the initiative by the IMO's MEP (through the work of the RDIWG) to progress the introduction of a competitive market for LFAS along with the introduction of a competitive Balancing market.

3.1.2 Balancing Support Contracts

Balancing Support Contracts (**BSC**) allow IPP facilities to assist Verve Energy in providing the required balancing requirements to the energy market.[54] The Market Rules allow System Management to initiate the development of these contracts or for Verve Energy to enter into them of its own accord.

Despite various attempts by Verve Energy and IPPs to negotiate suitable arrangements, no BSCs have been put in place since market commencement, which suggests one or both parties perceive there are unacceptable risks or contractual barriers in attempting to negotiate and/or execute a BSC.

It was noted in the 2010 Report to the Minister that the RDIWG was tasked with developing a solution to provide increased economic opportunities for generators other than Verve Energy to participate in the Balancing market. The RDIWG assessed several

[51] See IMO website, Ancillary Service Report 2011 prepared under clause 3.11.11 of the Market Rules by System Management - 27 June 2011, p. 9, http://www.imowa.com.au/f2841,1297737/Ancillary_Service_Report_2011_FINAL.pdf

[52] Under Clause 3.11.8B of the Market Rules, System Management must obtain the approval of the Authority before entering into an Ancillary Service Contract for Dispatch Support Ancillary Services. Clause 3.11.8C of the Market Rules requires the Authority to review whether the Ancillary Service Contract for Dispatch Support Ancillary Services (submitted under clause 3.11.8B of the Market Rules) would achieve the lowest practicably sustainable cost of delivering the services.

[53] In February 2010, System Management's issued its first call for Expressions of Interests (EOI) in the competitive procurement of LFAS, which resulted in no expressions being received. The difficulties identified with acquiring LFAS from this EOI were due to the limitation that the availability payment is linked to variable, and difficult to forecast, Balancing price and the requirement for the EOI to be a discount to that paid to Verve Energy. Subsequently, System Management provided a presentation to the RDIWG in October 2010 on how a competitive market for LFAS could be established using an offers and bids process in a day-ahead market. Subsequently, the RDIWG decided the development of a competitive LFAS market was to be added to the MEP's work program.

[54] If energy under a BSC is scheduled through Resource Plans then it has no special treatment in the market. However, if System Management must call on energy under BSCs in real-time, then the energy scheduled will be credited to Verve Energy for market settlement, while the IPP providing the energy will not be settled by the market for that energy. This arrangement assumes that the Verve Energy funds the provider of energy under the terms of its BSC.

options, including the introduction of enhanced arrangements for BSCs. Ultimately, the RDIWG agreed that enhanced BSC arrangements, such as increased transparency around dispatch, were unlikely to meet the objective of increased economic opportunities for IPP participation in Balancing. A major identified barrier was that an IPP's participation in Balancing would be limited to times (or events) that Verve Energy opted to contract for Balancing assistance.

The Authority notes two advantages that the proposed competitive Balancing market can provide over enhanced BSC arrangements:

- IPPs will have greater flexibility to decide as to when they will participate in Balancing support, rather than being called upon intermittently under a contract; and
- the central clearing nature inherent in the design of a competitive Balancing market should alleviate impediments to participant-to-participant BSCs associated with credit risk, because the IMO will have a prudential role.

The Authority also notes that with the finalisation of the Rule Change Proposal *RC_2011_10 Competitive Balancing and Load Following Market,*[55] BSCs will be removed from the WEM's design from 1 July 2012.

3.2 Inappropriate and anomalous market behaviour

The Market Rules require that the Authority, with the assistance of the IMO, must monitor instances of inappropriate and anomalous market behaviour, including behaviour related to market power.

The Authority considers that Market Participants behaviour has been largely acceptable. In its 2010 Report to the Minister, the Authority noted some incidences of Balancing Data prices (pay-as-bid prices) submitted by IPP's – particularly from Non-Scheduled Generators – that did not appear to be cost reflective. This matter is discussed in further detail in sections 4.5 and 5.2.2.1.

The Authority considers that the market power mitigation measures included in the Market Rules[56] combined with the other measures introduced at market commencement[57] have been effective in introducing new entry generation into the WEM, which has resulted in a steady reduction of Verve Energy's market share.

The Authority highlighted its previous Report to the Minister that any changes to the WEM, including incremental modifications, will raise issues of market power. The example cited in the previous Report to the Minister were the design changes being considered for the introduction of the new competitive Balancing and LFAS markets, include design features such as rolling gate closures, differential treatment for Verve Energy which is allowed to

[55] See IMO website, RC_2011_10 Competitive Balancing and Load Following Market web page, http://www.imowa.com.au/RC_2011_10

[56] The Market Rules measures to mitigate the use of market power in the WEM are: the price caps in the STEM (the 'Maximum STEM Price' and the 'Alternative Maximum STEM Price'); the administered prices in the Reserve Capacity Mechanism; Market Generators to offer their electricity at prices that reflects their SRMC when such behaviour relates to market power; and the monitoring regime involving market monitoring by the Authority and the IMO.

[57] Other measures introduced at market commencement include: a 3,000 MW generation capacity cap on Verve Energy; Verve Energy could not retail electricity until 2013 (extendable to 2016) and Synergy cannot generate until 2013 (extendable to 2016); and the Displacement Mechanism in the original Vesting Contract (2006) (noting that original Vesting Contract was replaced with alternative vesting arrangements on 1 October 2010).

bid at portfolio level whilst other participants are required to bid at facility level, and different pricing constraints applied to Balancing and LFAS submissions compared to the SRMC rule that applies to STEM submissions.[58]

The Authority notes that the IMO engaged the consultant Market Reform to assess the market power issue in the context of the proposed new Balancing and LFAS markets. In its report, Market Reform concluded the proposed market power mitigation features for the new market arrangements are appropriate to allow the detection of material market power abuses and, given diligent market compliance and surveillance monitoring, such abuses could be mitigated against before competition in the new markets was harmed.[59]

Market Reform's report noted that, short of breaking dominant generators into smaller companies, strategies for mitigating market power may include minimising the barriers to entry and facilitating competition so as to maximise competitive pressure on dominant generators. Market Reform's paper went on to note that, if situations arise where competition (under the new market arrangements) is inadequate to prevent the profitable exercising of market power in the Balancing market, there are also provisions in the rules specifying acceptable behaviour - in this case the SRMC rule that applies to Balancing submissions and the 'incremental cost' rule that applies to LFAS submissions.[60]

Based on discussions at various market forums, the Authority considers that the level of competition at the commencement of the new competitive Balancing and LFAS markets is likely to be fairly weak, particularly in the LFAS market. This is due to the new arrangements having only been finalised shortly before the commencement of these markets, which will result in a period where IPPs need to become familiar with the new arrangements, and develop the systems and processes to participate.

The Authority and the IMO will be closely monitoring compliance with the SRMC bidding clause applicable to the competitive Balancing market and the 'incremental cost' bidding clause for the LFAS market. The Authority agrees with the suggestion by Market Reform in its market power review report to the IMO that the market may need some guidance as to what constitutes appropriate behaviour, particularly regarding offers in the LFAS market. The Authority understands the IMO will provide further information regarding its approach to the front-line monitoring of the new competitive Balancing and LFAS markets leading up to their commencement.

3.3 Wholesale Electricity Market design problems or inefficiencies

The design of the WEM was influenced by the characteristics of the Western Australian energy market and the legacy of the industry's structure prior to the commencement of the WEM in September 2006.[61] In the past, stakeholders have expressed concerns that the complexity of the WEM – including the rules that govern the RCM, the net pool energy

[58] Clause 6.6.3 of the Market Rules require that a Market Generator must not offer prices into the STEM that do not reflect the Market Generator's reasonable expectation of the SRMC of generating the electricity when such behaviour relates to market power.

[59] See IMO website, Market Power Implications of the Planned Balancing and Load Following Ancillary Service Market Arrangements - 30 September 2011, http://www.imowa.com.au/f139,1751332/IMO_Market_Power_Review_-_Market_Reform_v1_0.pdf

[60] Market Reform's report also noted rules specifying acceptable behaviour require that diligent compliance monitoring is conducted relative to those provisions.

[61] The date and time at which the first Trading Day commenced, as published by the Minister in the Government Gazette. The date and time of market commencement was 21 September 2006 at 8.00 am.

market, as well as contractual arrangements between the state-owned corporations – can be barriers to new entry.

The Authority has been aware of the lack of competition in the Balancing market and in the provision of Ancillary Services required by the market. The Authority supports the proposed new competitive Balancing and LFAS markets, expected to commence in July 2012.[62]

The Authority has raised the issue that a competitive market for Spinning Reserve Ancillary Service (**SRAS**) was not included as part of the MEP which appears an oversight. The Authority considers there was a missed opportunity for the significant resources allocated to the MEP to also consider the design for a more efficient, competitive SRAS market at the same time as it was designing the Balancing and LFAS markets for a relatively small incremental cost, which may otherwise be more costly to revisit and introduce in the future. The Authority notes that, in terms of cost to the market over the past three years, the provision of SRAS has been approximately double that of the provision of LFAS.[63]

The Authority notes that Ancillary Service and energy markets are co-optimised in many electricity markets in other jurisdictions, including the NEM. This may be considered for the WEM as well.

The Authority is aware of the concerns raised by Rule Participants in relation to the RCM. The Authority understands that the IMO intends to convene a MAC working group early in 2012 to build on the work by the Lantau Group which was engaged by the IMO to conduct a review of the RCM,[64] and to investigate the effectiveness of the Reserve Capacity refund mechanism.

The Authority has commented on several of the market design problems and inefficiencies being addressed by these market programs, including:

- Ancillary Services Contracts and BSCs (section 4.1)
- The Reserve Capacity Mechanism (section 2.2) and the Reserve Capacity market (section 4.2)
- the STEM (section 4.4)
- Balancing (section 4.5).

[62] A summary of the market evolution process that identified the need for an evaluation of the Market Rules regarding a number of aspects of the WEM's design was included in the 2010 Report to the Minister. See ERA website, 2010 Report, pp. 154 – 155.

[63] Pursuant to clause 3.11.11 of the Market Rules, by 1 June each year System Management must submit an Ancillary Services report to the IMO, which includes information on the total costs of each of the categories of Ancillary Services provided in the preceding year. The 2009, 2010, and 2011 reports show that the total LFAS cost for the past three years (1 April 2008 to 31 March 2011) was approximately $29 million, while SRAS cost for the same period was approximately $56 million. See the IMO website, Annual Ancillary Services Report web page, http://www.imowa.com.au/ancillary-services-annual-reports

[64] See IMO website, MAC meeting No. 43 papers Agenda item 8 - Review of RCM: Issues and Recommendations Report by the Lantau Group, pp. 27 – 46, http://www.imowa.com.au/f4873,1594262/Combined_papers_meeting_43.pdf

3.4 Monitoring the problems with the structure of the Wholesale Electricity Market

A feature of the WEM is the continuing dominance of Verve Energy and Synergy, by virtue of their incumbent market positions. The Authority notes that Verve Energy's market share of credited generation capacity will be approximately 55 per cent in 2013.[65] Synergy's reported share of the retail market as at 30 June 2011 was 71 per cent.[66] There are currently structural barriers to effective retail competition, in particular in the residential and small commercial sectors of the market. At the same time, the upstream market in fuel supply (and transport) is still very much a long term bilateral contract arrangement. Together, these market characteristics limit new entrant to the WEM.

Aside from the commentary of a potential merger of Verve Energy and Synergy (discussed in detail in section 2.1), the Authority notes that the Minister is reviewing the restriction on Verve Energy from the direct sale of electricity to consumers (**Restriction**) and the prohibition on Synergy from generating electricity (**Prohibition**).[67] If the Minister decides to lift the Restriction and Prohibition, both Verve Energy and Synergy will be allowed to have integrated generation-retail businesses from 2013. In early 2011, the Office of Energy initiated preparations to assist with undertaking these reviews of Verve Energy and Synergy on behalf of the Minister for Energy.

The Office of Energy's 2010/11 Annual Report noted that:[68]

- it was intended that these reviews, as well as the first five-yearly review of the *Electricity Networks Access Code 2004*[69] and a review on whether further retail competition should be introduced for the supply of electricity in the SWIS,[70] would commence in the second half of 2011; however
- due to the complexity of the issues involved and ongoing market evolution processes including the Verve Energy Review and its outworking, the anticipated commencement for the reviews were not able to be met.

The Office of Energy's Annual Report did not provide any insight as to when these reviews were likely to be completed.

In the Discussion Paper for this report, the Authority noted the comments made by the Premier of Western Australia regarding a possible merger of Verve Energy and Synergy, and considered that a merger is likely to have consequences for outcomes in the WEM. The Authority last considered this issue in its 2009 Report to the Minister, in which the Authority concluded that a merger of Verve Energy and Synergy would undermine competition by deterring the entry of new generators and retailers in the WEM as well as undermining private investment in new generation facilities. The Authority also noted that

[65] Derived from the IMO Capacity Credit allocation for the 2013/14 Reserve Capacity Year – excluding credited DSM capacity.

[66] See Synergy web site, Annual Report 2010/11, p. 2, http://www.synergy.net.au/docs/Annual_Report_2010_11.pdf

[67] Section 38(1) of the *Electricity Corporations Act 2005* restricts the Electricity Generation Corporation (Verve Energy) from the direct sale of electricity to consumers for a designated period (herein referred to as the 'Restriction') and section 47(1) prohibits the Electricity Retail Corporation (Synergy) from generating electricity for a designated period. The designated period can be until 1 April 2013 or until 1 April 2016.

[68] See Office of Energy website, Annual Report 2010-11, http://www.energy.wa.gov.au/cproot/2911/2/Annual Report 2010-11_web.pdf

[69] Under Section 111 of the *Electricity Industry Act 2004*.

[70] Under Section 55 of the *Electricity Corporations Act 2005*.

ultimately, Western Australian electricity customers and taxpayers would bear the risks and costs of a shift back to a vertically integrated electricity monopoly.

The Authority invited stakeholders' views in the Discussion Paper on whether developments in the market since this issue was last considered by the Authority suggest that the Authority should reconsider its conclusion that a merger of Verve Energy and Synergy would undermine competition and impose costs and risks on customers. Section 2.1 provides a summary of stakeholders' views, and the Authority's conclusions, on the possible merger of Verve Energy and Synergy.

4 Review of the effective operation of the Wholesale Electricity Market

Clause 2.16.11 of the Market Rules requires that the Report to the Minister provides an assessment on the effectiveness of the market in dealing with matters identified in clauses 2.16.9 and 2.16.10 of the Market Rules. This chapter addresses the Authority's reporting requirements under clause 2.16.10.

Under Clause 2.16.10 of the Market Rules the Authority must review the effectiveness of:

- the Market Rule change process and Procedure change process;
- the compliance monitoring and enforcement measures in the Market Rules and Regulations;
- the IMO in carrying out its functions under the Regulations, the Market Rules and Market Procedures; and
- System Management in carrying out its functions under the Regulations, the Market Rules and Market Procedures.

In addition, Clause 2.16.12(b) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of the effectiveness of the market, including the effectiveness of the IMO and System Management in carrying out their functions, with discussion of each of:

- the Reserve Capacity market
- the market for Bilateral Contracts for capacity and energy
- the STEM
- Balancing
- the dispatch process
- planning processes
- the administration of the market, including the Market Rule change process.

This section sets out the Authority's assessment of the effective operation of the WEM, including (where relevant) an outline of stakeholders' comments. This section is structured as follows:

- Section 4.1 reports on the effectiveness of the administration of the WEM, and includes a discussion on the Market Rule and Procedure change processes, compliance monitoring and enforcement measures, and the effectiveness of the IMO and System Management in carrying out their functions;
- Section 4.2 reports on the Reserve Capacity market;
- Section 4.3 reports on the market for Bilateral Contracts for capacity and energy;
- Section 4.4 reports on the STEM;
- Section 4.5 reports on the Balancing market;
- Section 4.6 reports on the dispatch process; and
- Section 4.7 reports on the planning process.

4.1 Review of the effectiveness of the administration of the Wholesale Electricity Market

4.1.1 The effectiveness of the Rule Change Process and the Procedure Change Process

Among other matters, clause 2.16.10 of the Market Rules requires the Authority to review the effectiveness of the change process for the Market Rules and Procedures. This requirement is repeated in clause 2.16.12(b)(vii).

The Authority observes that the Rule Change Process and the Procedure Change Process are working as intended. As in previous Reports to the Minister, the Authority considers it appropriate that incremental changes to the WEM should continue to be managed through these processes. However, the Authority has recommended in this Report to the Minister that the existing governance arrangements in the WEM should be reviewed to determine whether the existing arrangements remain appropriate for the ongoing development of the market (see section 2.6).

In the Discussion Paper for this Report, the Authority considered it timely to consider the IMO's dual role in the Rule Change Process, and the Authority sought stakeholders' views to better understand these matters. Section 2.5 provides a summary of these views, and the Authority's conclusions and recommendations regarding the current governance arrangements for the Rule Change Process.

As noted in section 5.6.3, the IMO received 29 Rule Change Proposals during the current Reporting Period (i.e., 1 August 2010 and 31 July 2011). At the time of the release of this report, 25 Rule Change Proposals have commenced, two remained under development and two were not progressed. No Rule Change Proposals were rejected during the current Reporting Period.

As shown in section 5.6.3, these summary statistics are similar to the statistics in the previous reporting year. However, there have been notable changes to how the IMO has progressed some Rule Change Proposals during the current Reporting Period due to the following factors.

- As noted in the 2010 Report to the Minister, Market Participants have grown in their knowledge of the practical application of the Market Rules and Market Procedures. Informed debate occurs on market design development and on Market Rule, Procedure and system changes. While this debate may have slowed the change process in some instances, the Authority considers that such scrutiny is an indicator of a healthy evolution in the market.[71]
- Over the past two years considerable effort has been directed towards developing and implementing the next stage in the development of the market, being competitive markets for Balancing and LFAS. Rule Change Proposals have been

[71] For example, the Rule Change Proposals 2010_25 'Calculation of the Capacity Value of Intermittent Generation – Methodology 1 (IMO)' and 2010_37 'Calculation of the Capacity Value of Intermittent Generation – Methodology 2 (Griffin Energy)' both required the IMO to extend the timelines for the IMO to prepare its decisions due to the need for the IMO to carry out analyses on matters raised in public consultation on the proposed Amending Rules. The IMO also extended the public consultation period on these Rule Change Proposals after submissions had closed on the Draft Rule Change Report. The IMO's notice regarding this final extension and further consultation period acknowledged that clause 2.7 of the Market Rules does not specifically contemplate such further consultation on Rule Change Proposals. A similar further consultation period was held by the IMO for the Rule Change Proposal RC_2011_10 'Competitive Balancing and Load Following Market'.

deferred when the issues are being addressed by broader market review processes.[72]

During the current Reporting Period, the IMO submitted 10 Procedure Change Proposals into the formal Procedure Change Process, of which nine have commenced and one was withdrawn.[73]

On 6 September 2011, the IMO submitted the Procedure Change Proposal *PC_2011_06 5-Yearly Review of the Methodology and Process for Determining the Maximum Reserve Capacity Price* (**MRCP**) into the formal Procedure Change Process. This proposal attracted significantly more submissions during the consultation period (i.e., 10 in total) compared to other proposals submitted during the current Reporting Period, which attracted on average one submission each. Most of the submissions on PC_2011_06 noted stakeholders' opposition to the proposed amendments to the MRCP Market Procedure.[74] In the Procedure Change Report for PC_2011_06, the IMO noted that it had carried out a robust and consultative process prior to submitting the proposed amendments to the Market Procedure into the formal change process, therefore, it was not swayed by the arguments in submissions that noted opposition to the proposal. The Authority considers this to be an appropriate outcome.

4.1.2 The compliance monitoring and enforcement measures in the Market Rules and Regulations

Among other matters, clause 2.16.10 of the Market Rules requires the Authority to review the effectiveness of the compliance monitoring and enforcement measures in the Market Rules and Regulations.

The IMO monitors other Rule Participants' compliance with the Market Rules, investigates potential breaches of the Market Rules and takes enforcement action where appropriate, which can include applying to the Energy Review Board (**ERB**) for fines or other orders. Pursuant to clause 2.13.26 of the Market Rules, the IMO's produces biannual reports on enforcement action taken to the ERB. During the period 21 March 2011 to 20 September 2011 no new proceedings were brought before the ERB by the IMO.[75]

In November 2011, the IMO provided high-level details to the market regarding its proposed approach to compliance monitoring with the Market Rules to coincide with the commencement of the new competitive Balancing and LFAS markets.[76] The IMO also noted its plans to engage in site visits, education, and publishing guidelines, examples and case studies to assist Market Participants in their understanding of the revised compliance monitoring regime. The Authority considers the IMO's approach to provide early details of its proposed revisions to its compliance monitoring regime, and its offer to

[72] The IMO's draft decision on a Market Participant's Rule Change Proposal 2010_09 'Removal of DDAP Uplift when less than facility minimum generation' was deferred until the RDIWG had arrived at an in principle decision regarding changes to the application of UDAP and DDAP. Ultimately, the work of the RDIWG has resulted in the Rule Change Proposal RC_2011_10 in relation to this matter.

[73] System Management also submitted four Procedure change proposal during the Reporting Year, all of which have commenced. All submitted Procedure Changes by the IMO or System Management are listed on the IMO's website. See IMO website, Procedure Changes web page, http://www.imowa.com.au/procedure-changes

[74] See the IMO website, Procedure Change: PC_2011_06 web page, http://www.imowa.com.au/PC_2011_06

[75] The 2010 Report to the Minister reported on the IMO's biannual reports on enforcement action taken to the ERB up to the period 20 March 2011.

[76] See IMO website, Compliance Monitoring Regime presentation – 30 November 2011, http://www.imowa.com.au/f5181,1778780/IMO_Compliance_Monitoring_Regime_Presentation.pdf

interact with participants on the operation of the regime, to be a prudent and proactive step that is consistent with best-practice compliance monitoring in other jurisdictions.

The IMO's compliance with the Market Rules is audited once a year by the Market Auditor.[77] Pursuant to the Market Rules, the IMO requires that System Management either demonstrate compliance with the Market Rules and Market Procedures or undergo an audit by the Market Auditor. Each year since market commencement, System Management has elected to undergo audit by the Market Auditor. A summary of the Market Auditor's 2011 annual reports on compliance by the IMO, and by System Management, are set out in section 4.1.3 of this report.

The Authority understands that System Management has automated systems capable of identifying breaches of the Market Rules. System Management particularly focuses on its monitoring obligations regarding correct declaration of Forced Outages,[78] IPP's compliance with Resource Plans and Dispatch Instructions, and Verve Energy's compliance with dispatch orders and Ancillary Service requirements.

4.1.3 The effectiveness of the Independent Market Operator and System Management

Among other matters, clause 2.16.10 of the Market Rules requires the Authority to review the effectiveness of both the IMO and System Management in carrying out their respective functions under the Regulations, the Market Rules and Market Procedures.

In its 2010 Report to the Minister, the Authority considered that stakeholder comments, as well as the positive conclusions of the 2010 audit reports of the IMO and System Management,[79] indicated that the IMO and System Management have been generally operating effectively. Based on submissions for this report and informal discussions with stakeholders, the Authority notes overall that Market Participants continue to view the performance of the IMO and System Management in a favourable light.

While noting the matters raised in the most recent annual audit reports into the IMO's and System Management's compliance with the Market Rules, the Authority considers that both the IMO and System Management continue to effectively carry out their respective functions in the market under the Regulations, Market Rules and Market Procedures.

4.1.3.1 The Independent Market Operator

In submissions to the Authority's Discussion Paper, stakeholders commented on the performance of the IMO in particular contexts.

[77] The Market Auditor is an auditor appointed by the IMO to conduct at least annual audits of: the compliance of the IMO's internal procedures and business processes with the Market Rules; the IMO's compliance with the Market Rules and Market Procedures; and the IMO's market software systems and processes for software management. In addition, the Market Rules require that the IMO must at least annually require System Management to demonstrate compliance with the Market Rules and Market Procedures by providing such records as are required to be kept under the Market Rules or any Market Procedures, or subject System Management to an audit by the Market Auditor to verify compliance with the Market Rules and Market Procedures. In accordance with this requirement, the IMO has subjected System Management to an annual audit by the Market Auditor each year since market commencement.

[78] A Forced Outage is defined as any outage of a Facility or item of listed equipment that has not received System Management's approval. System Management manages a list of equipment subject to outages. For further information, see the IMO website, System Management Reports web page, http://www.imowa.com.au/system_management_reports.

[79] The IMO has appointed PA Consulting to be the Market Auditor each year since 2007. PA Consulting's 2011 audit reports are available on the IMO's website. See IMO website, Annual Compliance Audit web page, http://www.imowa.com.au/market_compliance_audit

Regarding the introduction of the competitive Balancing and LFAS markets, LGP considers that the IMO has performed well in developing and implementing the new markets, and fully supports the process the IMO has undertaken. LPG also noted the leadership void that exists within the industry, and considers the IMO is performing a leadership role in the wider interests of the industry. Synergy raised its concerns that the market has been corralled into accepting a radical change in the design of the new Balancing and LFAS markets. Synergy considered it was inconsistent with a June 2010 MAC recommendation against pursuing a more sophisticated market redesign agenda. Synergy noted a number of Rule Participants remained concerned that the more aggressive approach was not the timeliest solution, and that a series of smaller step changes would have been more consistent with the MAC's June 2010 recommendation. The Authority's views on the new market arrangements are set out in section 4.5.

Regarding market governance, Synergy noted on occasions the IMO has not provided full details to the market of reviews or assessments undertaken by the IMO's consultants. Synergy considers that, although there may be valid reasons for not revealing all the details to Market Participants, such behaviour lacks accountability and comes across as a governance weakness. System Management also expressed concerns on market governance in terms of the Rule Change Process, citing particular examples of shortcomings in recently progressed Rule Change Proposals.[80] The Authority's views and recommendations on market governance are discussed in detail in section 2.5.

Clause 2.14.3 of the Market Rules sets out the requirements for the audit of the IMO:

> The IMO must ensure that the Market Auditor carries out the audits of such matters as the IMO considers appropriate, which must include:
>
> a) the compliance of the IMO's internal procedures and business processes with the Market Rules;
>
> b) the IMO's compliance with the Market Rules and Market Procedures; and
>
> c) the IMO's market software systems and processes for software management.

In its audit report of the compliance of the IMO's internal procedures and processes with the Market Rules, and the IMO's compliance with the Market Rules and Market Procedures, PA Consulting found that the IMO has generally complied with its obligations under the Market Rules.[81]

[80] In this context, System Management referred to RC_2010_25 Calculation of the Capacity Value of Intermittent Generation - Methodology 1 (IMO), RC_2011_10 Competitive Balancing and Load Following Market and RC_2011_12 Extensions to Procedure Change Process Timelines.

[81] PA Consulting's compliance audit of the IMO found three (confirmed) material breaches and the materiality of one further breach was currently being investigated. Regarding the further breach being investigated, PA Consulting's report noted that the IMO failed to provide 'new and current' Capacity_R_Peak and Capacity_R_Off-Peak information to the settlement system for each Trading Month from July 2010 to June 2011 (as required under clauses 3.22.1(e) and (f) of the Market Rules). Regarding the three confirmed breaches, PA Consulting's report noted that all were one-off events and all have remedial actions associated with them designed to prevent their reoccurrence. The three confirmed material breaches were as follows. (i) Clauses 6.9.3, 6.9.5 and 6.9.6 of the Market Rules require that the IMO must determine STEM Offers and STEM Bids for each Market Participant for each Trading Interval, and the IMO must also determine aggregate STEM bid and offer curves for use in the STEM Auction. On 23 March 2011, the IMO's IT systems limited the number of participants to enter STEM Submissions to 50. The IMO implemented a fix to the systems the same day, and the next STEM Auction correctly included all participants. (ii) Clause 9.17.1 of the Market Rules requires the IMO to publish non-STEM settlement statements by the specified date and time. On 11 January 2011, the IMO failed to publish settlement statements on time. The problem was caused by a fault in a Wholesale Electricity Market Systems update. The IMO published the settlement statements two days later once a system fix had been developed, tested and released. The net impact was a two-day delay in the settlement of the market. (iii) Clause 9.22.8 of the Market Rules requires that the IMO must pay the full amount of an invoice to a participant in cleared

In its audit report of the compliance of the IMO's market software systems and processes for software management, PA Consulting concluded that other than a small number of non-material exceptions, the IMO's systems and process comply with the Market Rules.

Since the previous Report to the Minister, the Authority has observed a number of IT related issues with the IMO systems that have manifested in: the IMO not being compliant with a function under the Market Rules; and/or have impacted market outcomes. The following list summarises the market messages issued by the IMO during the current Reporting Period (1 August 2010 to 31 July 2011) related to IMO IT issues.

- On four occasions the IMO issued a Market Advisory giving notice of issues with the IMO's supporting infrastructure that resulted in a delay of either opening or closing the STEM Submission window, or the publication of STEM results.[82]
- On 2 March 2011, the IMO notified Market Participants that an IT systems issue that occurred on 1 March 2011 ultimately led to the suspension of the STEM for the following Trading Day.[83]
- On 23 March 2011, the IMO notified Market Participants that, due to a systems issue, the STEM results published on 23 March 2011 for 24 March 2011 Trading Day were not accurate.[84] The IMO also notified Market Participants that this issue reoccurred on 19 May 2011 affecting published STEM results for 20 May 2011.[85]
- On 19 August 2011, the IMO notified Market Participants that the intermittent Wholesale Electricity Market Systems (**WEMS**) performance issue that occurred on 18 and 19 August 2011 were caused by a larger than normal number of external connections attempting to connect to WEMS.[86]
- On 5 October 2011, the IMO notified Market Participants that the MCAP results for a number of Trading Intervals published since April 2011 appear to have been incorrect due to a system issue. In a follow up notification on 1 November 2011, the IMO's final analysis showed the issue affected a total of 121 Trading Intervals over the period from 5 April 2011 to 3 October 2011.[87]

funds by 2 pm on the settlement date specified in the invoice. On 10 February 2011, the IMO failed to pay System Management and the Authority as required for the period December 2010. Payments were created for 14 February 2011 instead. PA Consulting's report noted that the IMO intends to include a new section in its Operations Finance Procedure to capture short-payment steps and the process that needs to be followed in such circumstances.

[82] Under section 6.19.2 of the Market Rules the IMO must issue a Market Advisory for future potential events described in clause 6.19.1 if the IMO considers there to be a high probability that the event will occur in the next 48 hours. The four Market Advisories referred to are all titled 'STEM Window Delay' and were issued on: 25 September 2010 09:38 AM WST; 22 November 2010 09:30 AM WST; 25 January 2011 10:30 AM WST; and 25 January 2011 10:55 AM WST. See the IMO website, Market Advisories web page, http://www.imowa.com.au/n131.html

[83] Market message emailed to Market Participants from IMO Operations on 2 March 2011. The reported issue was that the security technology (Certificates) used to authenticate user access to the Wholesale Electricity Market Systems (WEMS) had failed.

[84] Market message emailed to Market Participants from IMO Operations on 23 March 2011. The reported issues was that the system has disregarded the STEM and Bilateral nominations from two parties when the STEM auction took place, due to the system limiting submissions into STEM to a maximum of 50 participants.

[85] Market message emailed to Market Participants from IMO Operations on 19 May 2011. The reported issue was that the STEM auction process had again limited submissions into STEM to a maximum of 50 participants. The IMO noted this was the same issue that occurred on 23 March 2011, and the problem was re-introduced as part of the WEMS release because the new release over-wrote the previous patch.

[86] Market message emailed to Market Participants from IMO Operations on 19 August 2011.

[87] Market messages emailed to Market Participants from IMO Operations on 5 October 2011 and 1 November 2011. A spreadsheet attached to the latter notification detailed the published MCAP and what

The Authority considers it is a core function of the IMO to ensure that its systems are functioning effectively. In one instance, in explaining how difficult it was to address an IT issue related to the calculation of MCAP (last point above), the IMO noted the investigation and identification of the root cause of the issue had taken more than six person-weeks of effort.[88] In this particular instance, the Authority is concerned that the IMO's internal processes were not able to pick up errors in its calculations, i.e., the incorrect MCAP calculation had continued for many months and the investigation of the issue was only prompted when the Authority requested that the IMO check its calculation.

More broadly, the Authority is concerned that if the IT issues observed to date are not addressed appropriately, there is the potential that the number of issues may increase in step with the increasing complexity of the WEM's design (e.g., the Balancing and LFAS markets). If this were to occur, it may lead to a serious detrimental impact of the effectiveness of the market. Such problems could be further compounded when IT systems become increasingly relied upon for key calculations as the market moves towards closer to real time dispatch. The Authority will closely monitor developments in this area.

4.1.3.2 System Management

Clause 2.14.6 of the Market Rule sets out the requirements for the audit of System Management:

> In accordance with the Monitoring Protocol, the IMO must at least annually, and may more frequently where it reasonably considers that System Management may not be complying with the Market Rules and Market Procedures:
>
> a) require System Management to demonstrate compliance with the Market Rules and Market Procedures by providing such records as are required to be kept under these Market Rules or any Market Procedure; or
>
> b) subject System Management to an audit by the Market Auditor to verify compliance with the Market Rules and Market Procedures.

In its audit report of System Management's compliance, PA Consulting found that System Management has generally complied with its obligations under the Market Rules.[89]

In the 2010 Report to the Minister, it was highlighted that PA Consulting's 2010 audit report of System Management's compliance had noted that there had been no new entries in System Management's compliance log recorded since the previous audit. PA Consulting's 2011 audit report notes that System Management has since begun the process of embedding compliance monitoring and reporting into operational processes, and PA Consulting noted an increased awareness of the reporting of compliance

it should have been and the difference. The differences range from \$0.02 to \$105.61 with an average across all 121 intervals of \$11.59.

[88] Market messages emailed to Market Participants from IMO Operations on 5 October 2011 regarding incorrect MCAP results for a number of Trading Intervals published since April 2011.

[89] PA Consulting's compliance audit of System Management found three material breaches as follows: (i) System Management excluded Curtailable Load, Intermittent Generation and commissioned generation from the calculation of the MT PASA (as required under clause 3.16 of the Market Rules); (ii) System Management excluded Curtailable Load, Intermittent Generation and commissioned generation from the calculation of the ST PASA (as required under clause 3.17 of the Market Rules); and (iii) System Management did not subtract forecast wind generation from the Load Forecast provided to the IMO twice daily (as required under clause 7.2.2(a) of the Market Rules). PA Consulting noted that: in the first two cases remedial steps were being taken with System Management and the IMO having discussed a method to define a reasonable and prudent non-zero amount for the excluded capacity, but agreement has not been reached; and in the third case System Management has implemented changes to the calculation so that the forecast now matches the Market Rules.

breaches, and as a result, a more reasonable number of relevant entries in the compliance log.

4.2 The Reserve Capacity market

Clause 2.16.12(b)(i) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of the effectiveness of the Reserve Capacity market.

The RCM has been in operation in WA since 2005. The objective of the RCM is to secure sufficient generation and DSM capacity to meet the peak load of the SWIS.

The Authority is of the view that the RCM has been successful in securing sufficient capacity to meet forecast requirements,[90] with the number of Capacity Credits[91] assigned to participants exceeding the Reserve Capacity Requirement (**RCR**) in each Capacity Year.

The Authority also notes other positive market outcomes have flowed, at least in part, from the RCM:[92]

- a significant increase in the Capacity Credits assigned to new entrants, where the share of capacity provided by IPPs has grown from approximately 11 per cent in 2005/06 to approximately 49 per cent in 2013/14; and
- there have been no reported instances of curtailment of electricity supply due to capacity shortages since the commencement of the RCM.[93]

However, the Authority notes that, while the RCR has grown at approximately five per cent over the seven capacity cycles to the 2013/14 Capacity Year, the average Capacity Credits procured in excess of the RCR over the same period has been approximately 7.5 per cent.

As discussed in the Authority's previous reports to the Minister, generating plant investment decisions are based on a host of factors including projected price and quantity values resulting from the RCM, such as: the MRCP and the RCP (discussed in more detail below), energy and fuel prices, carbon tax, other business variables, and factors outside of the WEM.

Rule Participants have raised their concerns on various aspects of the RCM. As discussed in the Discussion Paper for this Report to the Minister, these concerns have been recently investigated by the Lantau Group which was engaged by the IMO Board.

[90] The RCM operates on a two-year-ahead cycle and is designed to secure sufficient capacity to meet forecast demand.

[91] The RCM is built around the concept of a Capacity Credit. This is a notional unit of Reserve Capacity provided by a generator or DSM provider. Each year, the IMO prepares an assessment of the amount of capacity that is required to meet the forecast demand. If, in a particular year, the IMO determines that 100 MW of capacity is required, it will seek to ensure that this is provided by offering to purchase 100 Capacity Credits from generators and DSM providers. Capacity Credits have significant value. Capacity Credits can either be traded bilaterally or through the market. In return for receiving this payment, generators are required to offer their capacity into the market at all times (unless undergoing scheduled maintenance on a Planned Outage).

[92] As noted in Section 5.1.4, the Authority considers increased competition in the capacity market has also been a result of the Displacement Mechanism in the original Vesting Contract (2006) and the 3,000 MW generation capacity cap applying to Verve Energy.

[93] However, as noted in the Executive Summary, whilst there are no instances of reported curtailment of electricity supply due to capacity shortages, the Authority notes that this comes at a significant cost to customers.

The Lantau Group produced its paper "Review of the RCM: Issues and Recommendations".[94] The key issues that have been identified are the Reserve Capacity refund mechanism and efficient procurement of capacity in terms of both pricing and volume, and capacity mix.

The Authority notes the IMO Board recommended that the MAC convene a working group in 2012 to build on the Lantau Group's work on the RCM, as well as to investigate the effectiveness of the Reserve Capacity refund mechanism. The Authority notes the recently formed RCMWG will consider these matters. These matters are discussed in further detail in section 2.2.

The Authority notes that the MRCP for the 2014/15 Reserve Capacity Year has decreased by approximately one third in comparison to the previous capacity year. This reduction is caused by a combination of year-on-year variation in input parameters and the methodology changes as a result of the revised Market Procedure which came into effect in October 2011.[95] The impact of year-on-year variation in the input parameters led to an 11 per cent reduction in comparison to the previous capacity year. This reduction is predominately caused by a significant (lower) shift in the Weighted Average Cost of Capital, for which key parameters are determined from observed bond yields. The impact of the methodology changes as a result of the revised Market Procedure contributed a 23 per cent reduction (i.e., after taking account of the year-on-year variation in the input parameters).[96]

Synergy noted in its submission that if capacity appeared expensive, as represented by a RCP that is too high, then there is reluctance on the part of Market Customers (i.e., retailers) to procure capacity. Synergy proposes enhancements to the existing RCM or alternatives to the RCM that should be considered by the IMO's proposed RCM working group. The Authority considers that all proposals should be considered on their merit, but recommends the IMO carry out a thorough, consultative and transparent process in assessing and recommending proposed changes to the current RCM. The Authority also notes that it has made recommendations in this report that changes be considered to the market governance arrangements surrounding significant proposed changes to the WEM's design, which is discussed in section 2.6 of this report.

As noted in the 2010 Report to the Minister, the Authority is due to review the methodology for determining the MRCP by no later than October 2013.[97] While the Authority has the option of undertaking this review earlier, the Authority considers that this review should not be brought forward until the IMO MAC working group has completed its review of the RCM (and has demonstrated that the current arrangements can be improved) and there is a defined outcome for the future network access model, i.e., a decision on whether to move to constrained transmission network operation.

[94] See IMO website, MAC meeting No. 43 papers Agenda item 8 - Review of RCM: Issues and Recommendations Report by the Lantau Group, pp. 27 – 46, http://www.imowa.com.au/f4873,1594262/Combined_papers_meeting_43.pdf

[95] The Market Procedure for determining the MRCP was amended via the Procedure change process following a review and consultation process spanning 16 months from May 2010 to October 2011. For further information see the IMO website: (i) Procedure Change: PC_2011_06 web page, http://www.imowa.com.au/PC_2011_06; and (ii) Maximum Reserve Capacity Price Working Group web page, http://www.imowa.com.au/MRCPWG

[96] Further details on the reduction caused in the MRCP for the 2014/15 Reserve Capacity Year by the combination of year-on-year variation in input parameters and the methodology changes as a result of the revised Market Procedure are discussed in the IMO's Final Report: Maximum Reserve Capacity Price Review for the 2014/15 Capacity Year. See the IMO website, Maximum Reserve Capacity Price web page, http://www.imowa.com.au/mrcp

[97] Pursuant to Market Rule 2.26.3.

4.3 The market for Bilateral Contracts for capacity and energy

Clause 2.16.12 (b) (ii) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of the effectiveness of the market for Bilateral Contracts for capacity and energy.

As noted in the 2010 Report to the Minister, while the Authority has an interest in ensuring that the bilateral market helps promote the Wholesale Market Objectives, particularly in terms of facilitating new entry in the generation sector and the retail sector, the precise counterparties and terms of Bilateral Contracts are confidential and are not a topic for the report to the Minister.

Market data for previous years showed that commercial bilateral agreements had progressively replaced the 'non-contestable' supply of capacity (Capacity Credits) and energy from Verve Energy to Synergy, with the Displacement Mechanism in the original 2006 Vesting Contract being a major influence on this outcome.

The Authority notes that the majority of bilaterally traded quantities continue to be traded between Verve Energy and Synergy. This outcome is to be expected given Verve Energy and Synergy continue to be the largest generator and the largest retailer in the market, respectively. However, the average annual bilaterally traded quantities per Trading Interval between Verve Energy and Synergy has decreased significantly when comparing the last three reporting periods (i.e., including the current Reporting Period). The Authority notes that this decrease during the first two reporting periods is likely a result of Synergy's Supply Procurement program required under the Displacement Mechanism in the original Vesting Contract (2006).[98] A significant decline in bilaterally traded quantities between Verve Energy and Synergy coinciding with Synergy's increased Bilateral trade with other Market Participants during the current Reporting Period indicates that Synergy may be procuring Bilateral quantities from other Market Participants beyond the volumes prescribed in the replacement Vesting Contract.

In its 2010 Report to the Minister, the Authority noted the changes in the 2010 Vesting Arrangements. Market data for the current Reporting Period, which includes the effective date of the commencement of the replacement Vesting Contract, appears to indicate that the replacement Vesting Contract has not had an immediate effect on dampening bilaterally traded quantities between 'other' Market Participants, i.e., excluding quantities traded between Verve Energy and Synergy.

The Authority also notes the increase in bilaterally traded quantities between 'other' Market Participants has coincided with an increase in the number and size of these entities in the market. The Authority expects that this increased competition in the bilateral market should lead to more efficient outcomes in that market.

4.4 The Short Term Energy Market

Clause 2.16.12(b)(iii) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of the effectiveness of the STEM.

[98] The original Vesting Arrangements, inclusive of the original Vesting Contract's Displacement Mechanism was terminated on 1 October 2010.

The STEM allows Market Participants to make adjustments around their bilateral positions. The STEM is operated a day ahead, with half-hourly prices established by auction for the subsequent day. As a part of the STEM's design, STEM Clearing Prices capture the system marginal price irrespective of the quantities traded in the STEM. The effectiveness of the STEM in capturing the system marginal price is dependent on the cost reflectivity of the STEM Offers and STEM Bids and how close the conditions assumed in STEM Submissions are to real-time conditions.

Overall, the Authority considers that while the STEM has certain limitations it is fulfilling its function in the WEM. The Authority also considers that STEM Clearing Prices have generally reflected the balance of supply and demand.

A key limitation identified with the STEM's design is the timing of its single gate closure, which occurs one to two days ahead of real time dispatch. The concern with this design is that changes in Market Participant's circumstances (e.g., fuel and plant availability) and improved temperature forecasts cannot be factored in to adjust participant's contract positions and they are therefore exposed to the Balancing market for any deviations between contract and actual positions.

As noted in the 2010 Report to the Minister, this matter was reviewed by the RDIWG as a part of its deliberations with the results of analysis showing that there were likely to be insufficient benefits compared with costs to warrant a change to the STEM's design. Instead the RDIWG elected to focus on improving the current Balancing market design to allow IPP's the opportunity to provide Balancing and improving the mechanism to handle unexpected events between the timing of the STEM Auction and dispatch. As such there are no direct changes to the STEM's design as part of the suite of changes made to the WEM's design under the Rule Change Proposal *RC_2011_10 Competitive Balancing and Load Following Market*.[99] However, the anticipated increased availability of market data as a result of this Rule Change Proposal should improve the effectiveness of the operation of the STEM (and Balancing market) by providing greater information to Market Participants upon which they can prepare their STEM Submissions.

While the current STEM design has its limitations, the Authority's continuing view is that a transparent wholesale price, such as that provided by STEM Clearing Prices, is an important feature of an effective energy market, particularly in promoting new investment. With the removal of the price discovery mechanism under the original Vesting Contract's Displacement Mechanism and until the new competitive Balancing and LFAS markets are implemented, the STEM is the only information mechanism whereby new entrants can discover information about demand and pricing in the market that is based on a competitive outcome to enable them to make decisions about entry. The Authority considers that a transparent and competitive energy market is important if the market is to continue to achieve the Market Objectives.

Section 5.2.1 reports on STEM outcomes since market commencement, including STEM Clearing Prices, traded quantities, and bids and offers. This section also includes a discussion on particular outcomes for the current Reporting Period.

In terms of the notable outcomes for the current Reporting Period, Table 4 in Section 5.2.1.1 shows that both average peak and average off-peak period STEM Clearing Prices increased in comparison to the previous reporting period, by approximately 21 per cent (to \$46.63/MWh) and 32 per cent (to \$25.68/MWh), respectively. However, this Reporting Period's STEM Clearing Prices remained lower than the long term average, i.e.,

[99] See IMO website, RC_2011_10 Competitive Balancing and Load Following Market web page, http://www.imowa.com.au/RC_2011_10

represented by the period from market commencement to 31 July 2011. As can be seen in Figure 4 in Section 5.2.1.1, higher prices occurred during February and March 2011, and again in June and July 2011. As discussed in Section 5.2.1.1, the higher average prices in late February and early March 2011 coincided with the shutdown of production at Varanus Island due to the effects of Cyclone Carlos, whereas the Authority understands that the higher average prices in late June and early July 2011 coincided with a large amount of generation capacity being given approval to take Planned Outages. The outage planning process is also discussed in sections 2.4 and 4.7.

4.5 Balancing

Clause 2.16.12(b)(iv) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of the effectiveness of the Balancing mechanism.

In the WEM, Balancing refers to the process for meeting Market Participant's actual (real-time) supply and consumption energy levels from contracted bilateral and STEM positions. Currently, Balancing support services are provided by Verve Energy as default balancer and there is only limited opportunity for IPP's to provide Balancing at certain times.[100]

Even with its limitations, the Authority considers that the current Balancing market has fulfilled its function in the WEM. Section 5.2.2 reports on Balancing outcomes since market commencement including Balancing prices and trade quantities. This section also includes a further discussion on particular outcomes for the current Reporting Period. As noted earlier, the Balancing market enables Market Participants to meet their actual (real-time) supply and consumption energy levels from contracted bilateral and STEM positions. Generally, System Management will match supply and demand in the system using Verve Energy's facilities. However there are circumstances in which System Management can issue Dispatch Instructions to other Market Participants.

Where Market Participants are issued Dispatch Instructions to increase or decrease supply in real-time, these deviations are settled on a 'pay-as-bid' price basis. Market Participants other than Verve Energy must specify pay-as-bid prices for increasing and decreasing the output of their facilities (and for decommitting facilities including switching off Intermittent Generators).[101]

Under the Market Rules, the IMO is required to review changes of Standing Data submitted by Market Participants, including pay-as-bid Balancing prices. Part of this requirement is to ensure submitted data represents the reasonable costs of the Market Participant in the circumstances related to the price or payment. Under clause 2.34.7 of the Market Rules, the IMO may reject a change in Standing Data related to prices and payments if it is not satisfied with evidence provided that the submitted data represents the reasonable costs of the Market Participant in the circumstances related to that price or payment.

[100] IPP's participation in Balancing is restricted to times of: system security situations; or as alternatives to the dispatch of Verve Energy's distillate facilities when there has been a shortfall between the market's requirements and Verve Energy's supply capacity.

[101] One set of prices apply for the whole Trading Day. IPP Market Participants can submit energy related Balancing Data to the IMO daily or can specify it via Standing Data that applies for every day. Pay-as-bid decrease prices for non-scheduled generators and decommitment price data is only recorded in facility Standing Data (as opposed to trading Standing Data) and cannot be submitted daily with energy market submissions. The IMO use Balancing Data to produce a number of Dispatch Merit Orders, describing the order in which non-Verve Energy facilities should have their output increased, decreased, or decommitted by System Management. Facilities with multiple fuel options appear multiple times in the Dispatch Merit Order, once for each fuel.

As noted in the 2010 Report to the Minister, the Authority has raised its concern with the IMO regarding the IMO's review of Standing Data related to prices and payments that are submitted by Market Participants to the IMO. The Authority notes that Standing Data Balancing Prices have generally tended to increase over the current Reporting Period for Non-Liquid Fuel facilities (shown in Figure 59) and Intermittent Generators (shown in Figure 61 and Figure 62), which is a continuing trend over recent past reporting periods.

During March 2012, the Authority sought an update from the IMO regarding its review processes of Standing Data related to prices and payments that are submitted by Market Participants. In response the IMO advised the following.

- Since December 2011, the IMO's Market Participant Interface (**MPI**) requires that the Market Participant's user provide reasons for Standing Data changes in Standing Data change requests. Change requests are assessed by the IMO based on the nature of the change and the reason/s given, to assess whether the change appears reasonable in the circumstances. If not, the IMO may request further information, including evidence be provided concerning the change notification.
- The IMO has not requested further information or evidence, and has not rejected any Standing Data price change requests since the changes were made to the MPI (i.e., in December 2011).

4.6 The dispatch process

Clause 2.16.12(b)(iii) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of the effectiveness of the dispatch process.

The WEM operates under a 'hybrid' design in terms of dispatch. The key characteristics of the hybrid design are as follows.

IPPs commit and dispatch their facilities to meet Resource Plans under a 'net dispatch' regime. IPPs can only deviate from their Resource Plans when dispatched by System Management for security reasons or to avoid Verve Energy generating using liquid fuel.

System Management manages overall system security, and schedules and dispatches Verve Energy's facilities to meet residual requirements under a 'gross dispatch' regime. It is also mandatory for Verve Energy to be the default provider of Balancing and Ancillary Services.

Chapter 7 of the Market Rules sets out the dispatch rules which affect the market development, market operations, system planning and system operations functions of System Management. As noted in Section 4.1.3.2, PA Consulting's 2011 audit report of System Management's compliance with its obligations under the Market Rules found that System Management had generally been compliant, including in relation to complying with its obligations under chapter 7 of the Market Rules.[102]

The dispatch process under the Market Rules allows System Management to adjust schedules in real-time to ensure that power system security and reliability is maintained while, to the extent possible, facilitating trade in accordance with bilateral and STEM

[102] Regarding System Management's obligations under chapter 7 of the Market Rules, PA Consulting noted one material breach, insofar as System Management did not subtract forecast wind generation from the Load Forecast provided to the IMO twice daily (as required under Clause 7.2.2(a) of the Market Rules). PA Consulting noted System Management has implemented changes to the calculation so that the forecast now matches the requirement under Market Rules.

positions. The current dispatch process is based on the market design of having a large incumbent generator (Verve Energy) in the role as the default balancing generator. System Management schedules Verve Energy's resources in accordance with a dispatch plan agreed by Verve Energy, and can only change IPP schedules (Resource Plans) under special circumstances.[103]

Two primary objectives of dispatch are to maintain system security and minimise the cost of dispatch. The Authority notes that the market's ability to minimise the cost of dispatch should be enhanced once the proposed Balancing and LFAS markets have been implemented from July 2012.

Key proposed changes to the dispatch regime to facilitate the proposed new markets are as follows.

- 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 and is the difference between Resource Plans and the net of total demand, non-scheduled generation and steady state requirements of plant providing LFAS.[104]
- Just prior to a dispatch interval, System Management will estimate the underlying MW trend in total generation requirements during the next dispatch interval. This quantity is referred to as the Relevant Dispatch Quantity (**RDQ**).
- System Management will formulate instructions to deliver Balancing (Balancing Dispatch Instructions) in accordance with the Final Balancing Merit Order to meet the expected RDQ.
- System Management will issue electronic Balancing Dispatch Instructions to Market Participants to ramp their Facilities to specified MW targets at specified ramp rates at (or from) a specified time within the interval.
- System Management will monitor system security and Facility responses to Balancing Dispatch Instructions during an interval and will issue new instructions if required.

Even with these fundamental changes to the dispatch regime from the status quo, the Authority notes that System Management will retain its overriding authority to intervene in order to maintain system security. The Authority considers this to be a common sense approach to the design of the dispatch regime under the new market arrangements.

However, the complexity of the new dispatch regime introduced by the new market arrangements will require System Management to develop appropriate support systems, and active participants will need to meet a certain level of capability in order to participate in the Balancing market.[105] The Authority understands that System Management and the

[103] System Management may issue Dispatch Instructions to other Market Generators and to Curtailable Loads or Dispatchable Loads if it cannot otherwise maintain security and reliability, or if it would have to use Verve Energy's liquid fuelled plant when non-liquid fuel capacity was still available.

[104] An instruction from System Management to load a facility to a specified level that is consistent with the offer from the market participant who is capable and has approval to provide LFAS. The LFAS tracks the instantaneous difference between demand, including losses, and all other production. This principle is unchanged from the current arrangements under the Market Rules.

[105] For example, design documentation for the new market arrangements indicates that System Management will require decision support software that incorporates the new rule requirements, the RDQ and the Final Balancing Merit Order. System Management will also need to develop systems to formulate and issue

IMO have finalised the criteria around these dispatch requirements, and that the Market Rules and Market Procedures will state that all active participants in the Balancing market must meet a certain level of technical and communication standards by a certain period in order to receive Capacity Credits.

The Authority will continue to monitor developments and report outcomes of the dispatch regime in future reports to the Minister.

4.7 Planning processes

Clause 2.16.12(b)(vi) of the Market Rules requires that the Report to the Minister contains the Authority's assessment of the effectiveness of the planning processes.

The Projected Assessment of System Adequacy (**PASA**) is a forecasting study, undertaken by the IMO in the case of the Long Term PASA, and undertaken by System Management in the case of a Short Term PASA and a Medium Term PASA.[106]

The annual Long Term PASA study determines the Reserve Capacity Target[107] for each Reserve Capacity Cycle[108] in the Study Horizon.[109] The study results are presented in the IMO's annual Statement of Opportunities report.[110]

The Short Term PASA assists System Management in assessing: the availability of capacity holding Capacity Credits; the setting of Ancillary Service Requirements in each six-hour period during the Short Term PASA Planning Horizon; and final approvals of Planned Outages. The Short Term PASA studies are based on a three week planning horizon. Medium Term PASA studies are developed for the same purposes as the Short Term PASA, but are instead based on a longer three-year planning horizon.

Overall, the Authority considers that the short, medium and long term PASA studies are operating as intended. However, as noted in the 2010 Report to the Minister, the market should continue to explore avenues for providing enhanced details that provide an indicator of market prices so Market Participants can better manage their risk, particularly in terms of the Short Term PASA. These information disclosures considerations need to be balanced against disclosing price sensitive information.[111] The Authority understands some improvements to outage information provision will coincide with the implementation of the new Balancing and LFAS markets (discussed later in this section), however as set out in section 2.4, the Authority recommends that the MAC should undertake a review of

electronic Balancing Dispatch Instructions. In addition, active market participants will need to provide System Management with an estimate of the start of interval generation level of a Facility to be able to dispatch these facilities, and be able to receive and acknowledge electronic Balancing Dispatch Instructions from System Management.

[106] The Short Term PASA is conducted in accordance with clause 3.17 of the Market Rules, while the Medium Term PASA is conducted in accordance with clause 3.16 of the Market Rules.

[107] In respect of a Capacity Year, the IMO's estimate of the total amount of generation or Demand Side Management capacity required in the SWIS to satisfy the Planning Criteria for that Capacity Year determined in accordance with clause 4.5.10(b) of the Market Rules, where Planning Criteria has the meaning given in clause 4.5.9 of the Market Rules.

[108] The cycle of events described in clause 4.1 of the Market Rules.

[109] The ten-year period commencing on 1 October of Year 2 of a Reserve Capacity Cycle.

[110] A report prepared in accordance with clause 4.5.13 presenting the results of the Long Term PASA study, including a statement of required investment if Power System Security and Power System Reliability are to be maintained.

[111] In the 2010 Report to the Minister, it was noted that due to the small number of generators in the market and the makeup of the generator fleet, individual Market Generators could be identified. Participants could potentially use this information in negotiating short-term bilateral contracts.

the outage planning process to consider whether the design of the RCM provides appropriate incentives for plant availability and whether a refund regime that links refund payments to system conditions would improve the incentives for availability.

The WEM's design also caters for an outage planning process of relevant equipment for maintenance purposes. The equipment list includes specific registered generation facilities that participate in the WEM, as well as network equipment. The current outage planning process is divided into long and short term components.[112]

Pursuant to the Market Rules, at least once in every five-year period, the IMO, with the assistance of System Management, must conduct a review of the outage planning process against the Market Objectives. This review must include a technical study of the effectiveness of the criteria System Management must apply when evaluating Outage Plans and include a public consultation process with Rule Participants. The IMO appointed the consultant PA Consulting to undertake the inaugural review of this process, and the consultant's final report was published on the IMO's website on 6 October 2011. The consultant was required to recommend any necessary updates to the Market Rules or *Power System Operating Procedure: Facility Outages* following the outcomes of the review and public consultation process.

PA Consulting's final report concluded that the outage planning process is generally functioning well and that no wholesale changes are required. However, PA Consulting did recommend four areas where the process can be fine-tuned.[113]

In the Discussion Paper for this Report, the Authority noted it sought to assess whether the current outage planning process is resulting in outcomes that are consistent with the Market Objectives. To assist the Authority in its assessment, the Authority sought stakeholder views on the current process. Section 2.4 provides a summary of stakeholders' views, and the Authority's conclusions and recommendations regarding the current outage planning process.

[112] Under the long-term component of the outage scheduling process, Rule Participants are required to submit Outage Plans up to three years in advance of the proposed outage to System Management. System Management then uses various criteria prescribed in the Market Rules and the PSOP to accept or reject these Outage Plans. Under the outage approval process (i.e., the short-term component), the Market Participants are required to apply to System Management to approve previously scheduled outages or undertake Opportunistic Maintenance (i.e., unscheduled outages). System Management then uses various criteria prescribed in the Market Rules and the PSOP to approve or reject the outage applications.

[113] PA Consulting's recommendations were as follows. (i) "Reserve Margin" In the interests of transparency, System Management should consider expanding the PSOP: Facility Outages to include how fuel composition factors into its considerations in the outage approval process. (ii) "Generation and network outage planning and their interaction" System Management should consider changes to clause 3.18.2(c)(i) of the Market Rules to the effect that the Equipment List should be constrained to 'all transmission network Registered Facilities that could limit the output of a generating facility or the participation of Demand Side Management during a planned outage'. (iii) "Outage approval timelines and constraints" (A) System Management should consider amendments to the PSOP: Facility Outages and, if necessary, the Market Rules to allow a limited number of advanced-approval outages per Facility per year. (B) The IMO should give consideration to an amendment to MR 3.19.2(b) to the effect that On-the-day Opportunistic Maintenance may be requested any time on the Trading Day or after 10am on the Scheduling Day. (iv) "Information disclosure and bias" (A) The IMO should, in conjunction with System Management and Market Participants, develop changes to the Market Rules establishing System Management's obligations with respect to the disclosure of information on planned outages. (B) There should be corresponding protocols within the PSOP: Facility Outages setting out how the new obligations are to be discharged by System Management. The protocols should encompass the following: the type of information to be made available (e.g., status of current planned outages, including information of major network outages and implications for generators, information on historic outages, etc.); the frequency with which the information is refreshed; and the form and mode by which this information is made available.

In terms of changes to the current outage planning process that will coincide with the implementation of the new competitive Balancing and LFAS markets, the notification of outages by System Management to the IMO will still be required.[114] However, in the interests of better promoting market efficiency, the timing of this information delivery will be modified to make the information available to the IMO (almost) immediately after the outage information is received by System Management. This information will then be published to the market through the IMO's MPI. In addition to the more timely delivery of outage information, non-scheduled generator outage information will also be provided to the IMO for the first time when the new Balancing and LFAS markets are implemented. It is also anticipated that the publication of System Management's Short Term PASA and Medium Term PASA reports on the Market Web Site will be timelier due to the proposed streamlining of the provision of this information between System Management's and the IMO's IT systems.

[114] Under clause 7.3.4 of the Market Rules, System Management must provide the IMO with a schedule of Planned, Forced and Consequential outages for each registered facility of which System Management is aware at the time.

5 Summary of the Market Surveillance Data Catalogue

Clause 2.16.12(a) of the Market Rules requires that the Report to the Minister contains a summary of the information and data compiled by the IMO under Clause 2.16.1 of the Market Rules. Clause 2.16.1 deems the IMO responsible for collecting and compiling the data identified in the MSDC, analysing the compiled data, and providing both the data and analysis to the Authority.[115]

The required summary of the MSDC data and analysis items for the reporting period from 1 August 2010 to 31 July 2011 (**Reporting Period**) is set out in this section and Appendix 3 of this report.[116]

To support the discussion of the MSDC data and analysis items for the Reporting Period, where relevant, the Authority has:

- drawn on MSDC data and analysis from periods earlier than the Reporting Period to show trends that have taken place since market commencement on 21 September 2006;
- drawn on other market data that is not a part of the MSDC data and analysis items;[117] and
- reported on annual periods from 1 October (8 AM) until the following 1 October (8 AM) when reporting on aspects of the Reserve Capacity market, as this is the period of time covered by a Reserve Capacity Year.

5.1 Reserve Capacity market

5.1.1 Number of participants in each Reserve Capacity Auction

Clause 2.16.2(b) of the Market Rules requires that the MSDC identifies the number of participants in each Reserve Capacity Auction.[118]

A Reserve Capacity Auction is run by the IMO only if the number of Capacity Credits assigned to facilities that have indicated their intention to trade their capacity bilaterally is insufficient to meet the system requirement and there are remaining certified capacities. As yet, there has been no requirement for the IMO to run a Reserve Capacity Auction.

[115] The data that is to be included in the MSDC is set out in Clause 2.16.2 of the Market Rules, and analysis of the data that the IMO must undertake is set out in Clause 2.16.4 of the Market Rules.

[116] This Reporting Period is consistent with previous Reports to the Minister prepared by the Authority, i.e., previous reports to the Minister have reported on the MSDC data and analysis items from 1 August to the following 31 July.

[117] In such cases, this is pointed out in the relevant discussion in support of the summary of such other market data.

[118] The process for determining the Reserve Capacity Price for a Reserve Capacity Cycle and the quantity of Reserve Capacity scheduled for the IMO for each Market Participant under Clause 4.19.

5.1.2 Reserve Capacity Auction offers

Clause 2.16.2(dA) of the Market Rules requires that the MSDC identify all Reserve Capacity Auction offers. As no Reserve Capacity Auction has been required to date, no auction offers can be reported.

5.1.3 Prices in each Reserve Capacity Auction

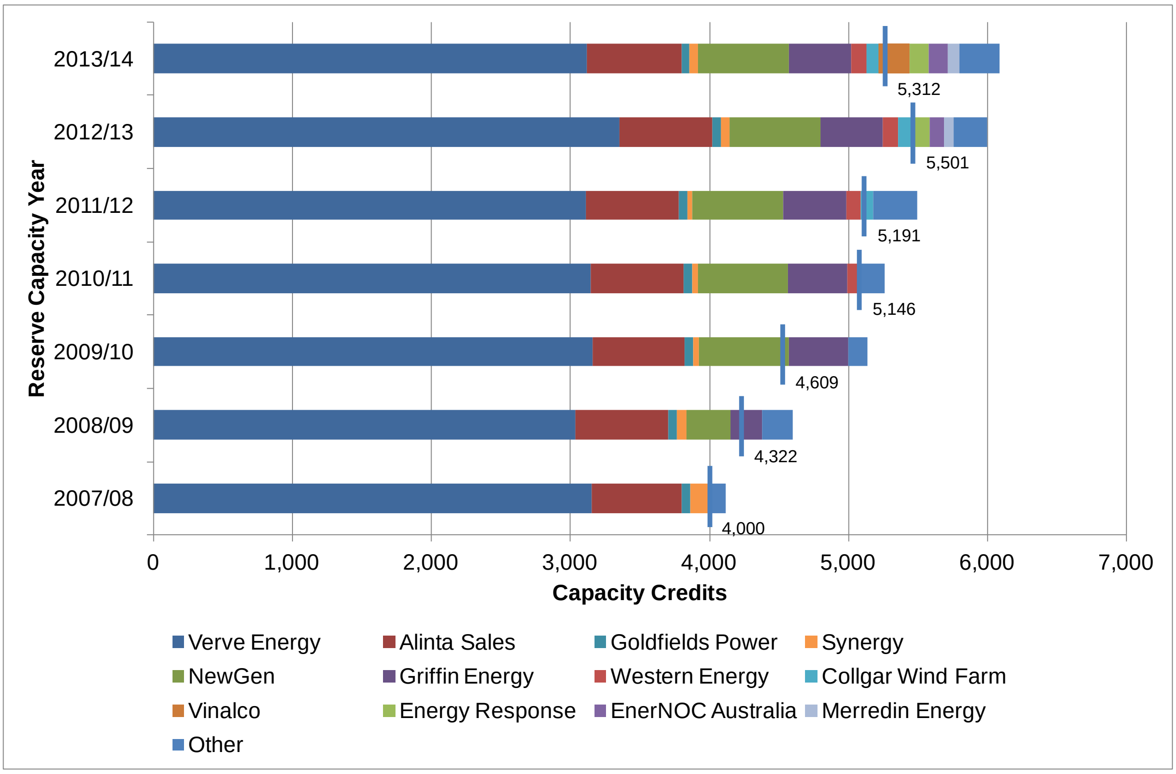
Clause 2.16.2(c) of the Market Rules requires that the MSDC identify clearing prices in each Reserve Capacity Auction. To date, there has been no requirement for the IMO to run a Reserve Capacity Auction.

5.1.4 Capacity Credits assigned

Although not required under the Market Rules, this section provides data on Capacity Credits assigned to Market Participants.

Figure 1 shows the Capacity Credits assigned to Market Participants for the 2007/08 to the 2013/14 Capacity Years, as well as the RCR for that year (shown as the vertical blue line for each Capacity Year). Over this period, the RCR has grown at an average of five per cent per Capacity Year.

Figure 1 Capacity Credits assigned to Market Participants for the 2007/08 to 2013/14 Capacity Years



Note: In the figure above, the vertical dashes with the corresponding value represent the Reserve Capacity Requirement in each Capacity Year.

It is clear from Figure 1 that in each Capacity Year the number of Capacity Credits assigned to participants (in aggregate) has exceeded the RCR. The excess of Capacity Credits assigned to participants has ranged from a low of approximately two per cent in the 2010/11 Capacity Year to a high of approximately 15 per cent in the 2013/14 Capacity Year, with an average over the seven years since the RCM commenced of 7.5 per cent. The high excess of Capacity Credits assigned to participants in the 2013/14 Capacity Year was in part a result of the RCR decreasing for the first time since the RCM commenced, by approximately 3.5 per cent in comparison to the previous year's RCR, which was due to a reduction in the IMO's forecast capacity requirements. This resulted in existing in-service or committed facilities representing a surplus of 684 MW of capacity above the RCR for the 2013/14 Capacity Year, prior to the introduction of approximately 91 MW of new capacity in that year.

Between the 2007/08 and 2013/14 Capacity Years, the SWIS has seen the introduction of approximately 2,000 MW of new generation and DSM capacity. The number of capacity providers and the proportion of capacity provided by IPPs have each grown considerably since market commencement, driven in part by the RCM, the Displacement Mechanism in the original Vesting Contract (2006) and the 3,000 MW generation capacity cap applying to Verve Energy.

By the 2013/14 Capacity Year, Verve Energy is expected to provide approximately 51 per cent of the total certified capacity in the SWIS, compared to approximately 56 per cent in the previous 2012/13 Capacity Year and approximately 90 per cent when the WEM commenced. Of the approximate 91 MW of new certified capacity added in the 2013/14 Capacity Year, the two significant capacities added were the Mumbida Wind Farm (15 MW) and an Enernoc Demand Side Programme (36 MW). In addition, a number of facilities saw either a small increase or decrease in their Capacity Credit assignments in that year.[119]

Table 12 in Appendix 3 provides a list of Market Generators and Market Customers registered at 2 September 2008, 6 October 2009, 14 October 2010 and 3 October 2011.

5.1.5 Maximum Reserve Capacity Price and Reserve Capacity Price

Although not required under the Market Rules, this section provides data on the MRCP and RCP.

The RCM's pricing mechanism is the administratively set MRCP, which is the price cap determined by the IMO for the Reserve Capacity Auction.[120] To date, there has been no requirement to procure capacity through a Reserve Capacity Auction. Without an auction,

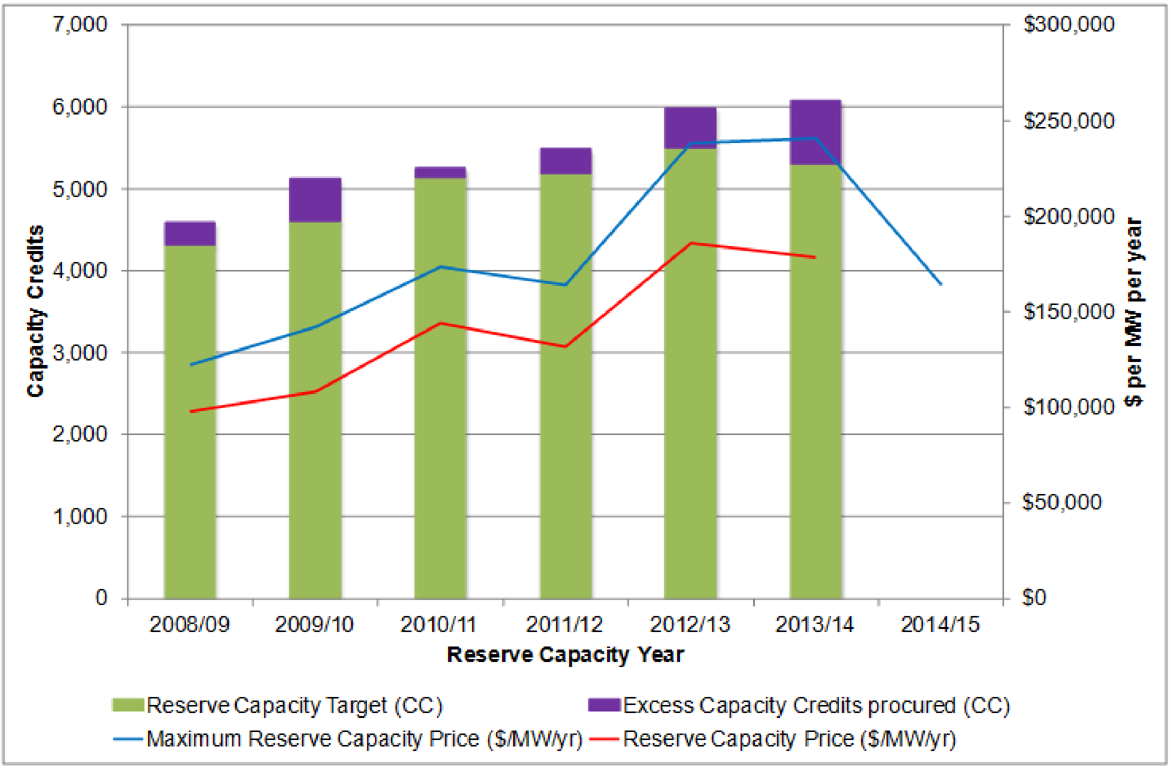
[119] See IMO website, Capacity Credits by Facility - market start to 2013/14, http://www.imowa.com.au/f180,1430115/Capacity_Credits_since_market_start_-_market commencement_thru_13-14.pdf

[120] If the RCR is not met through bilaterally traded capacity, the IMO can run the Reserve Capacity Auction to procure Capacity Credits for on-sale to Market Customers. The Reserve Capacity Auction is only held if there is insufficient capacity to meet forecast demand following the Bilateral Declaration process. Market Participants can offer capacity in the Reserve Capacity Auction at prices between $0/MW and the MRCP. If the Reserve Capacity Auction is held in any one year, the clearing price for the Reserve Capacity Auction becomes the RCP for all Capacity Credits traded through the IMO, except for facilities covered by a Special Price Arrangement granted in a previous year. If a Reserve Capacity Auction is held and a proponent is assigned Capacity Credits through the auction, it may take an option of a ten-year Special Price Arrangement. See the IMO website for further information, Special Price Arrangements webpage.

an administered RCP is paid per MW per year for Capacity Credits held by generators and DSM aggregators.[121]

Figure 2 shows the MRCP, RCP, Reserve Capacity Target and excess Capacity Credits procured (i.e., in excess of the Reserve Capacity Requirement) for each Capacity Year from 2008/09 to 2013/14.

Figure 2 The Reserve Capacity Target, excess Capacity Credits procured, Maximum Reserve Capacity Price and Reserve Capacity Price since the 2008/09 Capacity Years



Notably, a key long term trend of the RCM's administered pricing mechanism is that, with the exceptions of the 2011/12 and 2013/14 Capacity Years, the MRCP has increased significantly each year. The large increase in the MRCP in the 2012/13 Capacity Year was primarily due to an estimate provided by Western Power for the shared transmission connection cost, which was approximately 350 per cent higher than the estimated value provided by Western Power for the 2011/12 MRCP.[122] Western Power's shared transmission connection cost estimate for the 2013/14 MRCP was of a similar magnitude to its estimate for the 2012/13 Capacity Year.

[121] If a Reserve Capacity Auction is not held because enough capacity has been secured through bilateral trade nominations, the Market Rules set the price of all Capacity Credits at 85 per cent of the MRCP, as well as using a scale to adjust the value of Capacity Credits to take into account any oversupply of Capacity Credits in excess of the Reserve Capacity Target for that Capacity Year.

[122] That is, for the overall least expensive location. See IMO web site, Final Reports for the 2011/12 MRCP (shared connection cost of $10.158m) and 2012/13 MRCP (shared connection cost of $46.801m), available from http://www.imowa.com.au/mrcp and http://www.imowa.com.au/mrcp_archive

The Authority notes the reduction in the RCP in the 2013/14 Capacity Year in comparison to the previous year, even though the MRCP (marginally) increased in comparison to the previous year. This is a result of the increase in excess of capacity procured (over the Reserve Capacity Target) in the 2013/14 Capacity Year (i.e., approximately 15 per cent) compared to the 2012/13 Capacity Year (i.e., which was approximately 9 per cent).

The Authority also notes the MRCP for the 2014/15 Reserve Capacity Year has decreased by approximately one third in comparison to the previous capacity year, i.e., from $240,600 per MW per year for the 2013/14 Reserve Capacity Year to $163,900 per MW per year for the 2014/15 Reserve Capacity. This reduction is caused by a combination of year-on-year variation in input parameters and the methodology changes as a result of the revised Market Procedure which came into effect in October 2011.[123] The issue of the cost to the market of the capacity secured under the RCM is discussed in further detail in section 2.2.2.

5.1.6 Performance in meeting Reserve Capacity obligations

Clause 2.16.2(l) of the Market Rules requires that the MSDC identify the performance of Market Participants with Reserve Capacity obligations in meeting these obligations.

The performance of Market Participants with Reserve Capacity obligations is assessed by comparing the quantity of a Facility's Forced Outages and Planned Outages to the maximum generating capacity of the Facility, as registered by the IMO.

Table 3 sets out, for each Facility, the average across all Trading Intervals of the capacity subject to outages relative to the Facility's maximum generating capacity. Table 3 shows this for three periods – the 2008/09 through 2010/11 Capacity Years.

Generally, the Forced Outage rate for generation plant has been low – for most plant it has been well below two per cent. In the past three years the fleet Forced Outage rate has decreased from 2.6 per cent to 0.7 per cent, while over the same period, the fleet Planned Outage rate has increased from 9.2 per cent to 10.7 per cent.

Planned Outage rates are variable, reflecting the different stages of generation plant in their maintenance cycles. However, similar to the previous reporting period, the Authority notes that some facilities Planned Outage rates continue to be significantly higher in the current Reporting Period compared to earlier Reserve Capacity Years. The clearest examples in this Reporting Period are: Verve Energy's Kwinana G5 (53.6 per cent); Kwinana G6 (49.6 per cent); Pinjar GT 11 (49.3 per cent); and Muja G7 (42.7 per cent) generation plants.

The issue of transparency around the outage planning process was raised in the 2010 Report to the Minister. In that report the Authority noted that the IMO is required to undertake a 5-Year Outage Planning Review (as required under clause 3.18.18 of the Market Rules), and concluded that the Authority will comment on the outcome of this review in its 2011 Minister's Report.

In the Discussion Paper for this Report, the Authority noted it sought to assess whether the current outage planning process is resulting in outcomes that are consistent with the Market Objectives. To assist the Authority in its assessment, the Authority sought

[123] The Market Procedure for determining the MRCP was amended via the Procedure change process following a review and consultation process spanning 16 months from May 2010 to October 2011. For further information see the IMO website: (i) Procedure Change: PC_2011_06 web page, http://www.imowa.com.au/PC_2011_06; and (ii) Maximum Reserve Capacity Price Working Group web page, http://www.imowa.com.au/MRCPWG

stakeholder views on the current process. Section 2.4 provides a summary of stakeholders' views, and the Authority's conclusions and recommendations regarding the current outage planning process.

Table 3 Ratio of quantities subject to outages to maximum generating capacity for the 2008/09 to the 2010/11 Capacity Years

Participant	Resource Name	Max Gen (MW) 2008/09 Cap Year	Forced 2008/09 Cap Year	Planned 2008/09 Cap Year	Max Gen (MW) 2009/10 Cap Year	Forced 2009/10 Cap Year	Planned 2009/10 Cap Year	Max Gen (MW) 2010/11 Cap Year	Forced 2010/11 Cap Year	Planned 2010/11 Cap Year
Alcoa	ALCOA_WGP	25.0	2.1%	5.9%	25.0	2.4%	4.6%	25.0	5.1%	10.3%
Alinta Sales	ALINTA_PNJ_U1	145.0	1.1%	4.5%	145.0	0.1%	3.6%	145.0	0.2%	14.0%
Alinta Sales	ALINTA_PNJ_U2	145.0	0.2%	5.6%	145.0	0.0%	6.3%	145.0	0.1%	7.0%
Alinta Sales	ALINTA_WGP_AGG							380.0	0.0%	0.8%
Alinta Sales	ALINTA_WGP_GT	190.0	5.6%	2.1%	190.0	1.1%	0.6%	190.0	1.3%	1.8%
Alinta Sales	ALINTA_WGP_U2	190.0	0.0%	1.4%	190.0	1.0%	1.2%	190.0	0.0%	2.9%
EDWF Manager	EDWFMAN_WF1	80.0	0.0%	0.0%	80.0	0.0%	0.1%	80.0	0.0%	0.0%
Goldfields Power	PRK_AG	68.0	0.7%	1.6%	68.0	0.0%	1.5%	68.0	1.4%	6.1%
Griffin Power	BW1_BLUEWATERS_G2	208.0	39.3%	8.6%	217.0	1.7%	9.2%	217.0	1.2%	10.1%
Griffin Power 2	BW2_BLUEWATERS_G1				217.0	4.2%	2.4%	217.0	2.4%	8.7%
Landfill Gas and Power	CANNING_MELVILLE	3.0	0.0%	0.0%	3.0	0.0%	0.0%	3.0	0.0%	0.0%
Landfill Gas and Power	RED_HILL	3.3	0.6%	0.0%	3.3	0.0%	0.0%	3.3	0.0%	0.0%
Landfill Gas and Power	TAMALA_PARK	4.5	0.8%	0.0%	4.5	0.1%	0.0%	4.5	0.0%	0.0%
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1				342.0	0.1%	3.3%	342.0	0.0%	6.0%
NewGen Power Kwinana	NEWGEN_KWINANA_CCG1	324.0	1.2%	26.9%	324.0	0.7%	3.2%	324.0	0.9%	2.3%
Perth Energy	PERTHENERGY_KWINANA_GT1							116.0	0.1%	0.2%
Southern Cross Energy	STHRNCRS_EG	23.0	10.4%	2.6%	23.0	0.7%	1.4%	23.0	0.0%	0.0%
Tiwest	TIWEST_COG1	37.7	0.0%	3.0%	37.7	0.0%	4.6%	37.7	1.2%	3.1%

Participant	Resource Name	Max Gen (MW) 2008/09 Cap Year	Forced 2008/09 Cap Year	Planned 2008/09 Cap Year	Max Gen (MW) 2009/10 Cap Year	Forced 2009/10 Cap Year	Planned 2009/10 Cap Year	Max Gen (MW) 2010/11 Cap Year	Forced 2010/11 Cap Year	Planned 2010/11 Cap Year
Verve Energy	ALBANY_WF1	21.6	0.0%	0.1%	21.6	0.0%	0.0%	21.6	0.0%	0.2%
Verve Energy	COCKBURN_CCG1	236.6	0.2%	10.7%	236.6	0.0%	5.3%	236.6	0.0%	17.5%
Verve Energy	COLLIE_G1	315.0	0.8%	12.8%	318.0	0.3%	9.1%	318.0	0.6%	14.7%
Verve Energy	GERALDTON_GT1	20.8	0.0%	0.3%	20.8	0.2%	2.2%	20.8	0.4%	0.3%
Verve Energy	KEMERTON_GT11	154.0	0.0%	10.8%	154.0	0.0%	3.4%	154.0	0.0%	4.2%
Verve Energy	KEMERTON_GT12	154.0	0.2%	8.8%	154.0	0.0%	3.4%	154.0	0.0%	15.7%
Verve Energy	KWINANA_G1	111.5	2.0%	32.3%	111.5	0.1%	28.7%	111.5	5.2%	9.7%
Verve Energy	KWINANA_G2	111.5	3.3%	29.6%	111.5	3.1%	30.3%	111.5	4.9%	16.9%
Verve Energy	KWINANA_G5	177.0	0.0%	12.1%	177.0	1.0%	31.8%	177.0	0.0%	53.6%
Verve Energy	KWINANA_G6	177.0	0.2%	12.1%	177.0	0.0%	53.5%	177.0	2.5%	49.6%
Verve Energy	KWINANA_GT1	20.8	16.2%	35.6%	20.8	2.2%	22.8%	20.8	0.0%	21.9%
Verve Energy	MUJA_G5	185.0	2.5%	22.2%	185.0	0.7%	48.4%	185.0	15.8%	18.7%
Verve Energy	MUJA_G6	185.0	1.7%	25.5%	185.0	1.1%	28.0%	185.0	0.4%	20.5%
Verve Energy	MUJA_G7	211.0	0.4%	4.9%	211.0	1.6%	8.6%	211.0	0.0%	42.9%
Verve Energy	MUJA_G8	211.0	0.1%	28.4%	211.0	1.0%	4.8%	211.0	1.9%	18.5%
Verve Energy	MUNGARRA_GT1	37.2	0.8%	1.1%	37.2	0.3%	2.7%	37.2	0.0%	5.4%
Verve Energy	MUNGARRA_GT2	37.2	0.3%	1.1%	37.2	0.6%	5.4%	37.2	0.1%	0.7%
Verve Energy	MUNGARRA_GT3	38.2	0.9%	3.6%	38.2	1.5%	0.6%	38.2	1.5%	10.9%
Verve Energy	PINJAR_GT1	37.2	0.2%	4.2%	37.2	0.4%	1.1%	37.2	0.0%	7.4%

Participant	Resource Name	Max Gen (MW) 2008/09 Cap Year	Forced 2008/09 Cap Year	Planned 2008/09 Cap Year	Max Gen (MW) 2009/10 Cap Year	Forced 2009/10 Cap Year	Planned 2009/10 Cap Year	Max Gen (MW) 2010/11 Cap Year	Forced 2010/11 Cap Year	Planned 2010/11 Cap Year
Verve Energy	PINJAR_GT10	116.0	0.4%	35.1%	116.0	0.2%	11.8%	116.0	0.4%	10.4%
Verve Energy	PINJAR_GT11	123.0	0.2%	16.4%	123.0	0.0%	65.1%	123.0	0.1%	49.3%
Verve Energy	PINJAR_GT2	37.2	2.1%	5.5%	37.2	0.0%	1.1%	37.2	0.2%	5.2%
Verve Energy	PINJAR_GT3	38.2	0.0%	4.0%	38.2	0.0%	10.3%	38.2	0.3%	0.1%
Verve Energy	PINJAR_GT4	38.2	0.2%	4.1%	38.2	0.0%	20.4%	38.2	0.0%	1.7%
Verve Energy	PINJAR_GT5	38.2	0.0%	8.4%	38.2	0.2%	8.4%	38.2	0.4%	7.8%
Verve Energy	PINJAR_GT7	38.2	0.1%	0.3%	38.2	0.0%	29.9%	38.2	0.1%	0.2%
Verve Energy	PINJAR_GT9	116.0	0.0%	16.4%	116.0	0.1%	9.4%	116.0	0.0%	27.3%
Verve Energy	PPP_KCP_EG1	79.2	0.8%	4.6%	79.2	7.7%	1.9%	85.7	0.0%	4.7%
Verve Energy	SWCJV_WORSLEY_COGEN_COG1	119.0	22.8%	5.1%	119.0	1.0%	2.3%	116.4	1.8%	17.1%
Verve Energy	WEST_KALGOORLIE_GT2	38.2	0.4%	2.0%	38.2	0.0%	0.0%	38.2	0.1%	4.3%
Verve Energy	WEST_KALGOORLIE_GT3	24.6	0.0%	1.8%	24.6	0.0%	0.0%	24.6	0.0%	3.5%
Waste Gas Resources	HENDERSON_RENEWABLE_IG1	2.1	0.2%	0.0%	3.2	0.3%	0.0%	3.2	0.0%	0.0%
	Total (MW) and averages (%)	**4,696.2**	**2.6%**	**9.2%**	**5,268.3**	**0.7%**	**10.3%**	**5,768.2**	**1.0%**	**10.7%**

5.2 Energy markets

5.2.1 Short Term Energy Market

Clause 2.16.2(c) of the Market Rules requires that the MSDC identify clearing prices in each STEM Auction.

As well as the requirement under clause 2.16.2(c) of the Market Rules that the MSDC identify clearing prices in STEM Auctions, there are also requirements under clause 2.16.4 of the Market Rules to calculate:

- means and standard deviations of clearing prices in STEM Auctions;
- monthly, quarterly and annual moving averages of clearing prices in STEM Auctions;
- statistical analysis of the volatility of prices in STEM Auctions;
- the proportion of time that clearing prices in STEM Auctions are at each price limit;
- the correlation between capacity offered into the STEM Auctions and the incidence of high prices; and
- exploration of key determinants for high prices in the STEM.

This section summarises the results of the requirements under both clause 2.16.2 and clause 2.16.4 of the Market Rules.

5.2.1.1 Short Term Energy Market Clearing Prices

STEM Clearing Prices are summarised separately for Peak Trading Intervals (occurring between 8 am and 10 pm) and Off-Peak Trading Intervals (occurring between 10 pm and 8 am). There are significant differences between peak and off-peak clearing prices, both in terms of the average level of prices and the volatility of prices.

Table 4 sets out the mean and standard deviations of peak and off-peak clearing prices from:

- 21 September 2006 (market commencement) to 31 July 2011;
- 1 August 2009 to 31 July 2010 (i.e., the previous reporting period); and
- 1 August 2010 to 31 July 2011 (i.e., the current Reporting Period).

It can be seen that, for both peak and off-peak periods, clearing prices during the Reporting Period have significantly increased compared to the corresponding prices in the previous reporting period. Nevertheless, clearing prices in this Reporting Period remained lower than the long term average, i.e., represented by the period from market commencement to 31 July 2011.

Table 4 **Mean and standard deviations of STEM Clearing Prices ($/MWh)**

Trading Intervals	21 Sep 06 – 31 Jul 11		1 Aug 09 – 31 Jul 10		1 Aug 10 – 31 Jul 11	
	Mean	Std Dev	Mean	Std Dev	Mean	Std Dev
Off-Peak	32.37	28.99	19.51	11.63	**25.68**	**15.28**
Peak	63.87	57.12	38.65	18.80	**46.63**	**34.24**

Figure 3 and Figure 4 illustrate, respectively, average daily peak and off-peak STEM Clearing Prices for each Trading Day from 21 September 2006 (market commencement) up to 31 July 2011, as well as 30-day, 90-day and annual moving average prices.

Figure 3 **Average Peak Trading Interval STEM Clearing Prices (per Trading Day)**

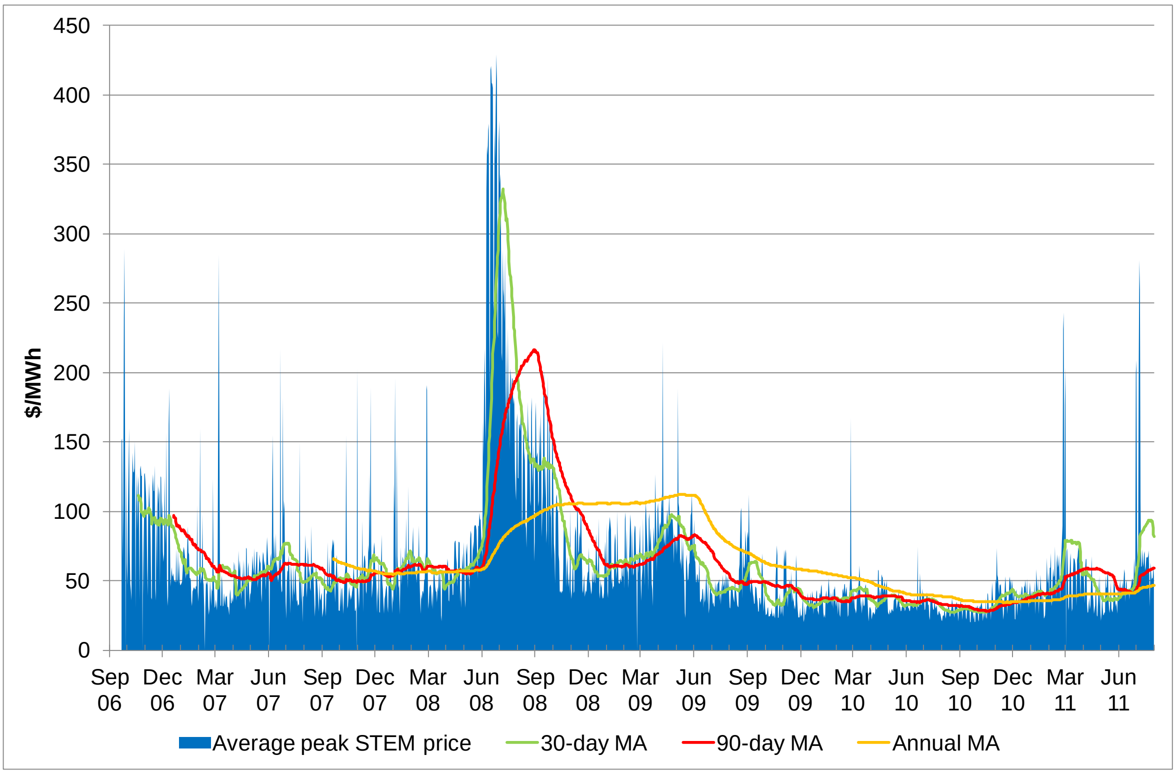
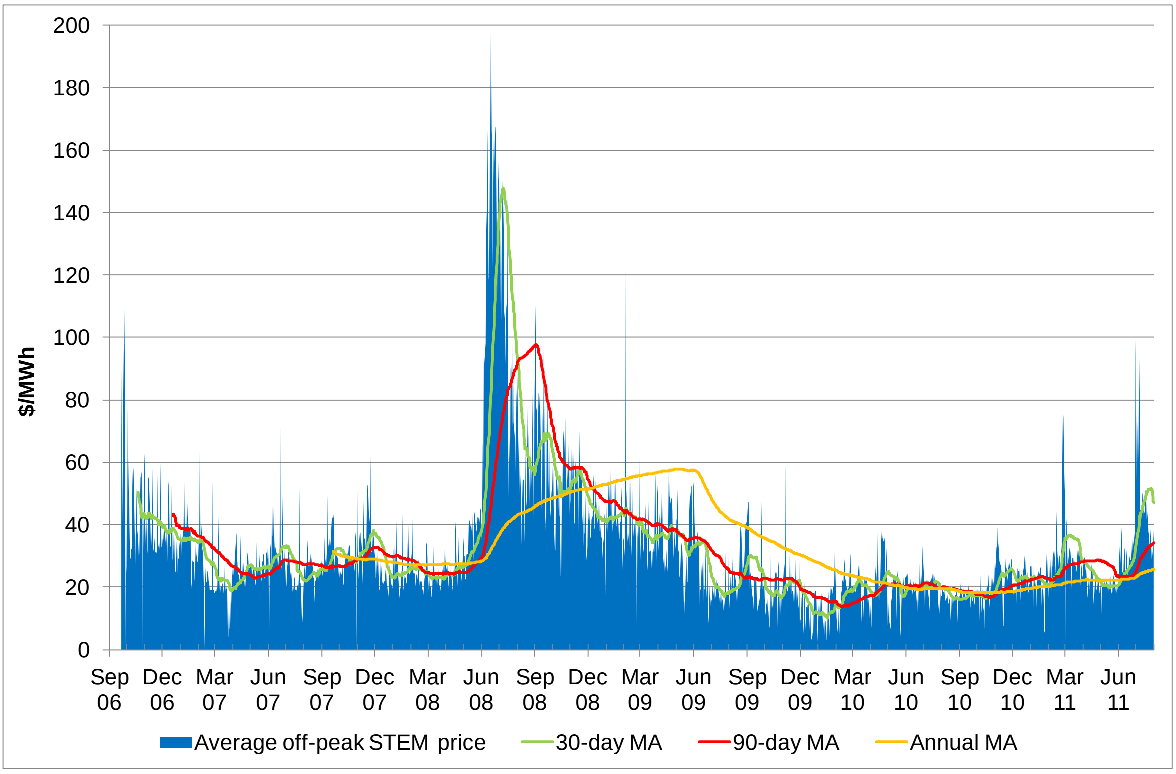


Figure 4 Average Off-Peak Trading Interval STEM Clearing Prices (per Trading Day)



Following a period of high prices immediately after market commencement, STEM Clearing Prices were relatively stable in 2007 and 2008, prior to the Varanus Island incident in June 2008.[124] Following the incident and the subsequent curtailment of gas supplies, prices increased significantly, peaking at a daily average in excess of $400/MWh during Peak Trading Intervals and a daily average of close to $200/MWh during Off-Peak Trading Intervals. Prices have decreased since that time, with average prices since the commencement of the 2008/09 Capacity Year (in October 2008) of approximately $50/MWh during Peak Trading Intervals and approximately $27/MWh during Off-Peak Trading Intervals.

However, during the Reporting Period, significantly higher average peak and off-peak period prices were observed during a number of days in late February and early March 2011, and again in late June and early July 2011. The higher average prices in late February and early March 2011 coincided with the shutdown of production at Varanus Island due to the effects of Cyclone Carlos. This gas supply disruption affected generation in the SWIS and lead to the declaration of a High Risk Operating State from 23 February 2011 until 1 March 2011. System Management issued a number of Dispatch Instructions and dispatched Curtailable Load during this period. The Authority understands that the higher average prices in late June and early July 2011 coincided with a large amount of generation capacity being given approval to take Planned Outages.

[124] The incident was caused by the rupture of a corroded pipeline and subsequent explosion at a processing plant on Varanus Island on 3 June 2008. The plant, operated by Apache Energy, which normally supplied a third of the State's gas, was shut down for almost two months while a detailed engineering investigation and major repairs were carried out. Gas supply from the plant was partially resumed in late August 2008. By mid-October 2008, gas production was running at two-thirds of normal capacity, with 85 per cent of full output restored by December 2008.

The lowest STEM Clearing Prices observed in off-peak periods during the Reporting Period occurred during January 2011, and which were primarily due to periods of low overnight load coinciding with lower cost capacity available in the dispatch merit order.

5.2.1.2 Volatility of Short Term Energy Market Clearing Prices

The Market Rules require the Authority to publish statistical analysis of the volatility of prices in STEM Auctions. Figure 5 and Figure 6 show the mean and standard deviation (as well as maxima and minima) by month of STEM Clearing Prices for peak and off-peak Trading Intervals from market commencement up to 31 July 2011.

Figure 5 and Figure 6 indicate that both peak and off-peak STEM Clearing Prices remained relatively stable during the current Reporting Period, with the highest volatility in STEM Clearing Prices occurring in both peak and off-peak periods during April 2011 and May 2011.

Figure 5 Summary statistics for STEM Clearing Prices in Peak Trading Intervals (per calendar month)

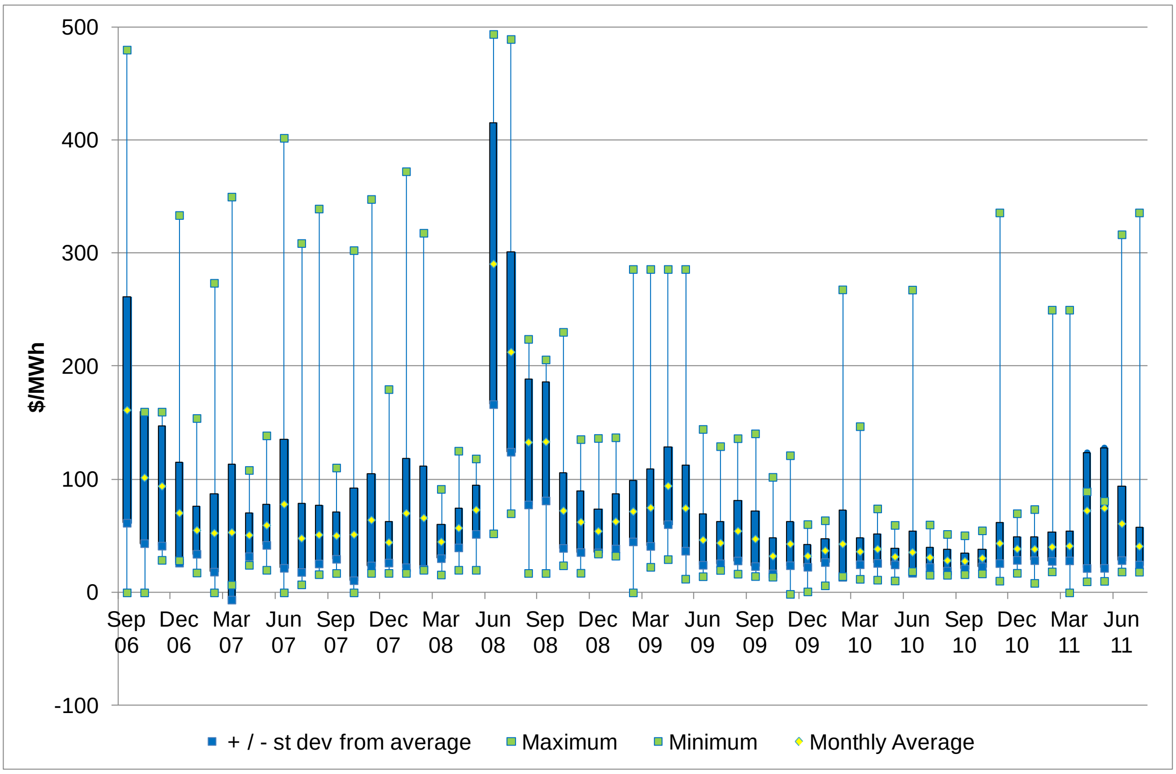
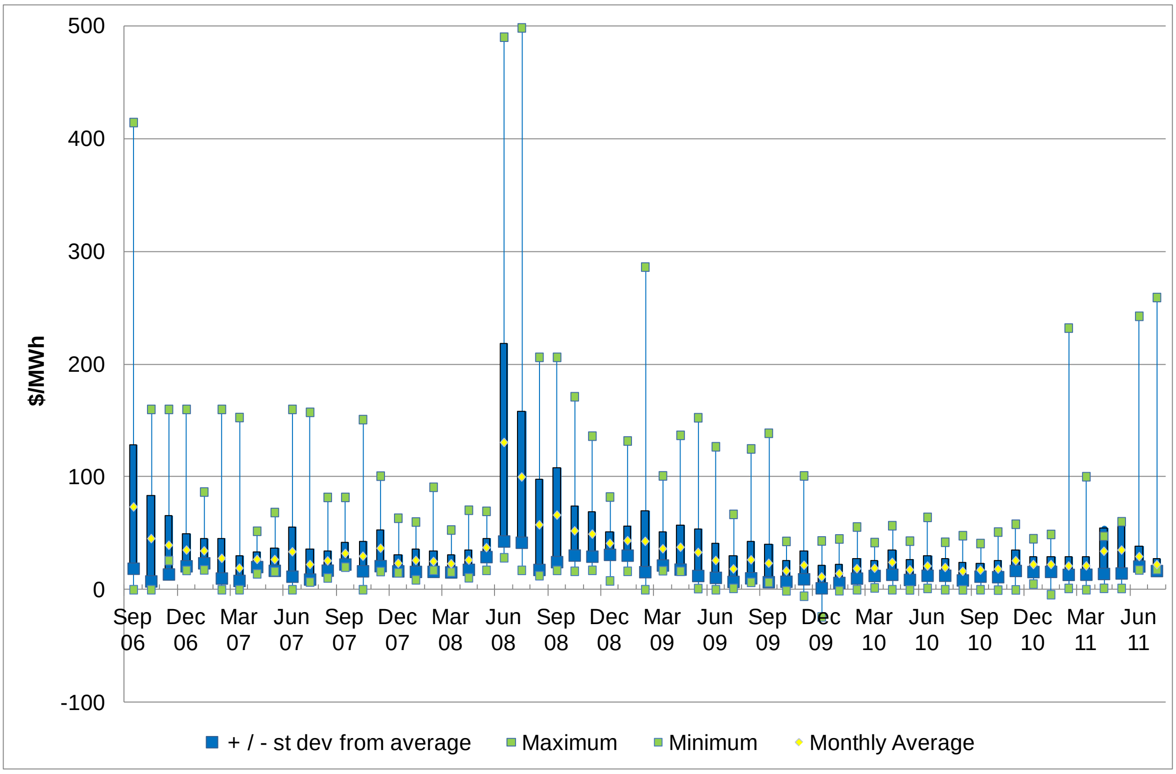


Figure 6 Summary statistics for STEM Clearing Prices in Off-Peak Trading Intervals (per calendar month)



5.2.1.3 High prices in the Short Term Energy Market

Clause 2.16.4 of the Market Rules requires an examination of both the incidence and the causes of high prices in the STEM. One way of examining the incidence of high prices is to assess the proportion of time that STEM Clearing Prices are at the Energy Price Limits. There are two Energy Price Limits set out in the Market Rules that act as a cap on high prices.

- Generation Capacity not running on Liquid Fuel must not be priced above the Maximum STEM Price. The Maximum STEM Price is based on the cost of an open cycle gas turbine. The Market Rules specify that the Maximum STEM Price is adjusted annually subject to review by the IMO. For the period from 1 October 2010 to 1 October 2011 the Maximum STEM Price was $336/MWh.
- Generation Capacity running on Liquid Fuel must not be priced above the Alternative Maximum STEM Price. The alternative Maximum STEM Price is based on the cost of a liquid fuel facility. The Market Rules specify that the Alternative Maximum STEM Price is adjusted monthly to reflect changes in oil prices and the consumer price index, and is subject to review by the IMO. Since market commencement, the Alternative Maximum STEM Price has been as low as $380/MWh and as high as $779/MWh.

Figure 7 and Figure 8 illustrate the proportion of peak and off-peak Trading Intervals during which STEM Clearing Prices were at the Maximum STEM Price and Alternative Maximum STEM Price.

Figure 7 shows that, since 2008, the highest incidence of both off-peak and peak STEM Clearing Prices reaching the Maximum STEM Price occurred between June and

September 2008, which coincided with the Varanus Island incident. STEM Clearing Prices also reached the Maximum STEM Price during peak Trading Intervals between March and May 2009 due to a significant number of plant outages, coinciding with a period of high demand. During the current Reporting Period, the STEM Clearing Price reached the Maximum STEM Price during three Peak Trading Intervals, twice on 3 November 2010 and once on 6 July 2011.[125]

Figure 7 Proportion of Trading Intervals STEM Clearing Prices at Maximum STEM Price (per calendar month)

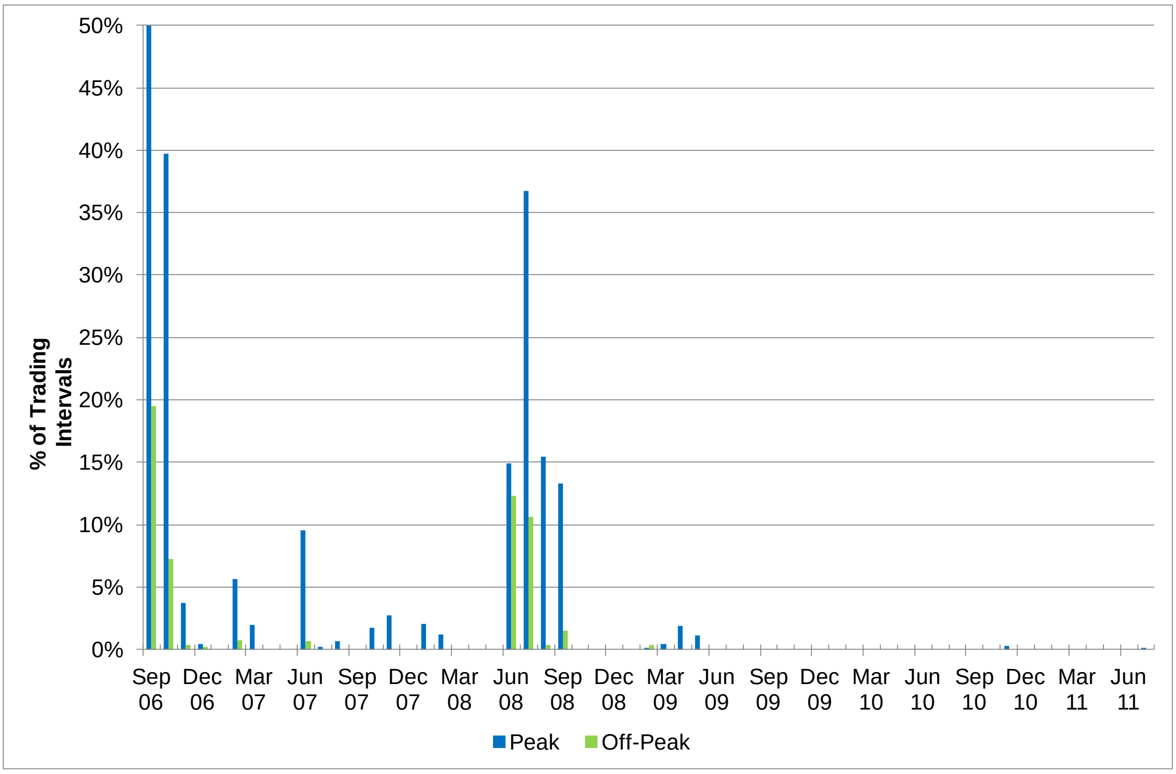
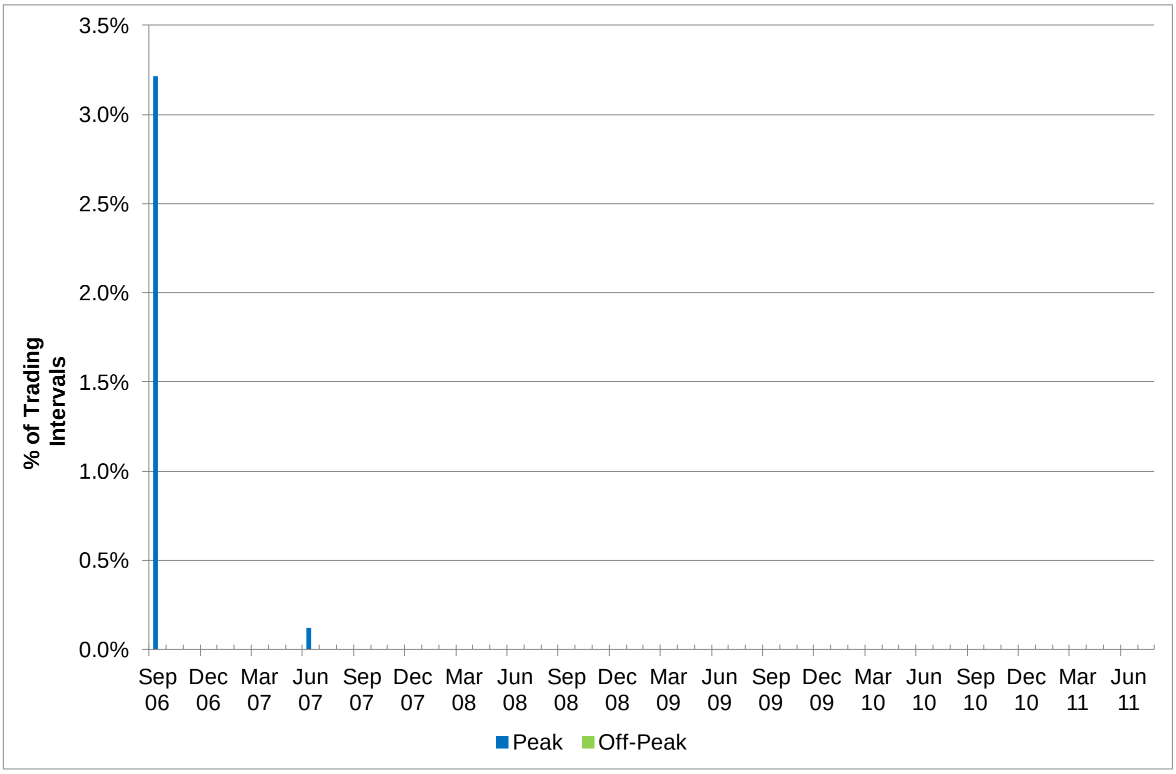


Figure 8 shows that STEM Clearing Prices have only reached the Alternative Maximum STEM Price during peak Trading Intervals in September 2006 and June 2007. Since then STEM Clearing Prices have not reached the Alternative Maximum STEM Price.

[125] The STEM Clearing Price at the Maximum STEM Price was isolated to two afternoon Peak Trading Intervals (2.30 pm to 3.00 pm) on 3 November 2010. These high prices were due to a combination of factors; however, this information is confidential and is not presented in this public version of the report. The STEM Clearing Price also reached the Maximum STEM Price during one Trading Interval on 6 July 2011 (at 6 pm), the STEM Clearing Price was above $300/MWh during seven consecutive Trading Intervals between 5.00 pm and 8.00 pm. These high prices were due to a combination of factors; however, this information is confidential and is not presented in this public version of the report.

Figure 8 **Proportion of Trading Intervals STEM Clearing Prices at Alternative Maximum STEM Price (per calendar month)**

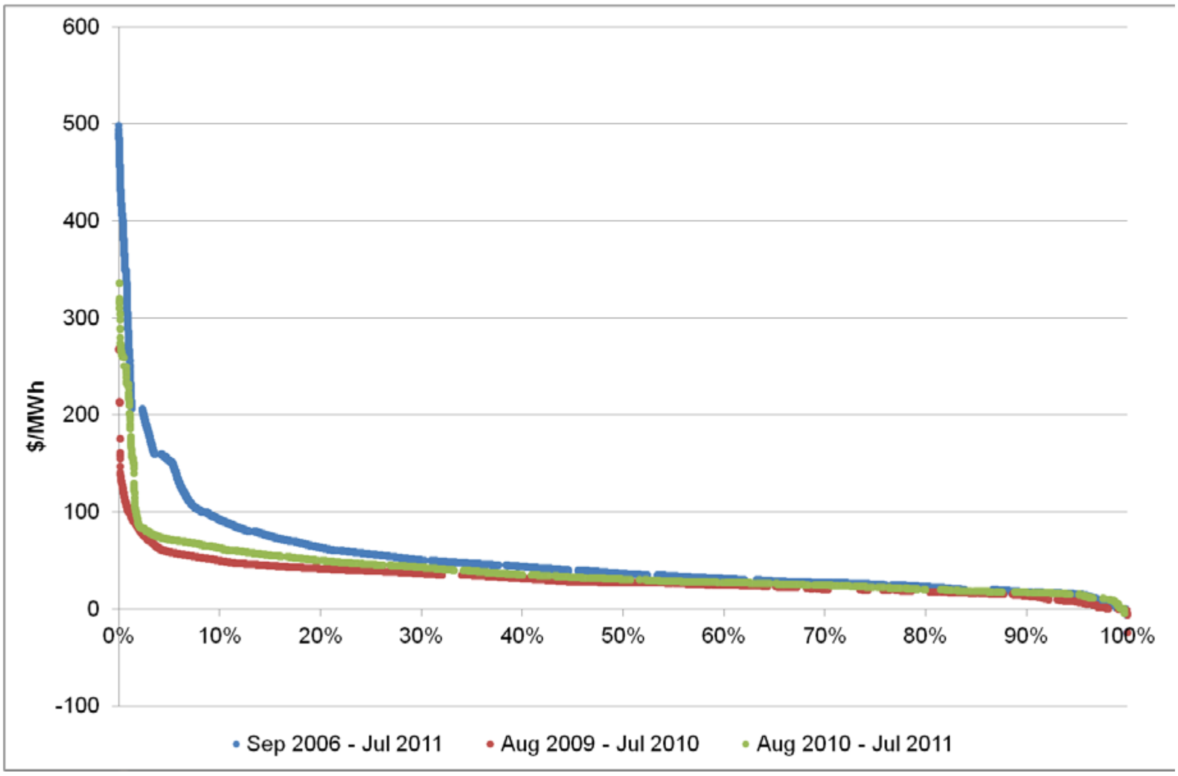


Another way of examining the incidence of high prices is to plot a price duration curve. Figure 9 sets out the price duration curves for STEM Clearing Prices, covering all Trading Intervals since 21 September 2006 (market commencement) to 31 July 2011, compared to the previous reporting period (August 2009 to July 2010) and the current Reporting Period.[126]

Figure 9 shows that STEM Clearing Prices fell between -$5.00/MWh and $100.00/MWh for approximately 97 per cent of Trading Intervals during the current Reporting Period, with a fairly even distribution of prices within this range. In the previous reporting period, prices fell between $-5.00/MWh and $100.00/MWh for approximately 88 per cent of Trading Intervals.

[126] Price duration curves for peak and off-peak period STEM Clearing Prices during the current Reporting Period are set out in Figure 75 and Figure 76 (respectively).

Figure 9 **Comparison of price duration curves for STEM Clearing Prices (past two annual reporting periods and 21 September 2006 and 31 July 2011)**



Clause 2.16.4(e) of the Market Rules requires the IMO to calculate the correlation between capacity offered into STEM Auctions and the incidence of high prices. In previous Reports to the Minister the Authority highlighted that a simple correlation between capacity and prices will fail to capture other factors that can influence STEM Clearing Prices, such as bidding behaviour and demand conditions, and that more detailed analysis was required to understand the key determinants of high prices in the STEM[127]. For these reasons, correlations between STEM Clearing Prices and quantities offered are not included in this report.

Clause 2.16.4(g) of the Market Rules requires the IMO to explore the key determinants for high prices in the STEM and Balancing. The Authority reported in previous Reports to the Minister that it was working with the IMO to develop an appropriate econometric model[128] for undertaking the analysis required under clause 2.16.4 (e) and clause 2.16.4 (g) of the Market Rules. At the time of the release of this Report to the Minister, this work was still ongoing. Progress on this matter will be reported in future Reports to the Minister.

5.2.1.4 Short Term Energy Market Offers and Bids

Clause 2.16.2(f) of the Market Rules requires that the MSDC identify all STEM Offers and STEM Bids, including both quantity and price terms.

[127] For example see ERA website, *Annual Wholesale Electricity Market Report for the Minister for Energy – 21 December 2007*, pp. 18-20, http://www.erawa.com.au/cproot/6444/2/20080319 Annual Wholesale Electricity Market Report for the Minister for Energy 2007.pdf

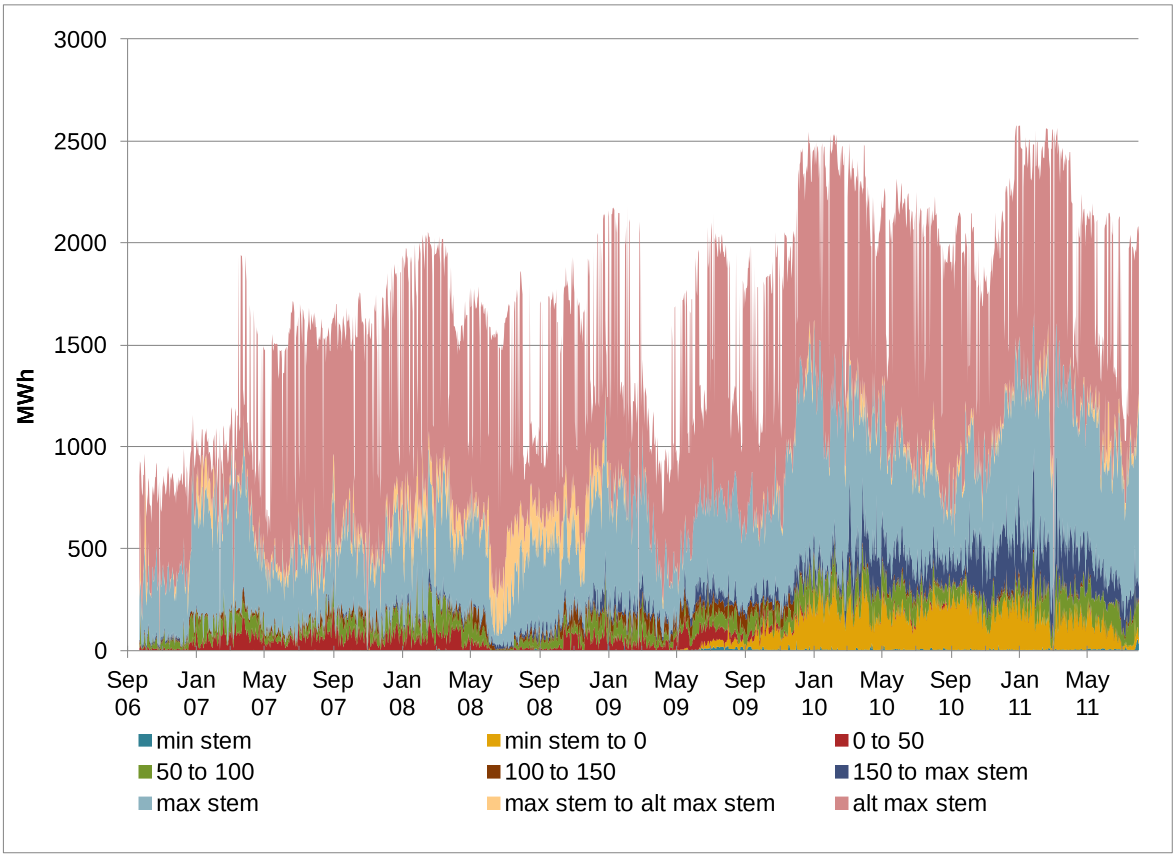
[128] This model estimates the numerical relationships between WEM variables such as temperature, load forecasts, energy prices, plant availability and fuel curtailments.

The Market Rules require that the IMO determine STEM Offers and STEM Bids for each Market Participant, and for each Trading Interval that a STEM Submission is received. The IMO determines STEM Offers and STEM Bids by converting a Market Participant's Portfolio Supply Curve and Portfolio Demand Curve into a single STEM price curve, and then convert this into STEM Offers and STEM Bids relative to the Market Participant's net bilateral position.

Short Term Energy Market Offers

STEM Offers reflect an increase in generation or a decrease in consumption. Figure 10 illustrates the daily average quantity of STEM Offers per Trading Interval for all Market Participants from market commencement until 31 July 2011.

Figure 10 Daily average quantity of STEM Offers (cumulative MWh per Trading Interval)



The majority of energy has consistently been offered at prices equal to the Maximum STEM Price and the Alternative Maximum STEM Price.[129] Smaller volumes tend to be offered at prices below the Maximum STEM Price, and the extent of offers below the Maximum STEM Price varies significantly over time.

[129] In constructing the STEM Offers and STEM Bids, a Market Customer's demand that is covered in a Bilateral Contract is defined as a STEM Offer. Since the value of electricity for end users is high, as evidenced in the high maximum spot price of $12,500/MWh in the National Electricity Market, Market Customers normally price reductions in their demand to reflect the high value for that electricity. In the WEM, this high priced demand becomes STEM Offers at the Alternative Maximum STEM Price. Thus, large quantities offered at the Alternative Maximum STEM Price are to be expected in the STEM.

It is notable that, since March 2010 onwards, Market Participants have offered increasing quantities in the STEM in the price range of $150/MWh to the Maximum STEM Price.

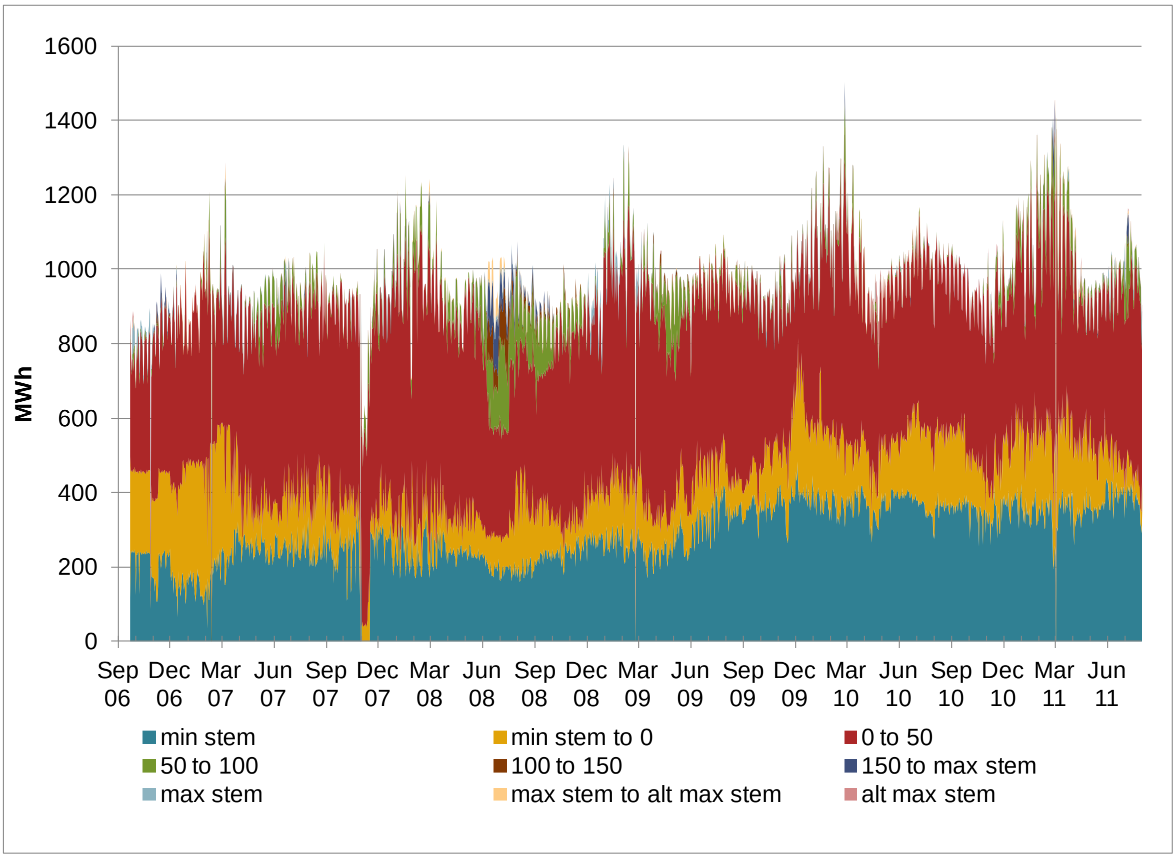
STEM Offers for each Market Participant are set out separately in Figure 29 to Figure 42 in Appendix 3. These figures show clear differences in the volumes and prices at which Market Participants have offered quantities into the STEM since market commencement. A discussion of notable changes in Market Participants' STEM Offers during the current Reporting Period is also included in Appendix 3.

It is notable that Verve Energy continues to account for the largest volumes of STEM Offers, with an average of 30.57 per cent of the total offer volumes during the current Reporting Period (compared to 33.34 per cent of the total offer volumes in the previous reporting period).

Short Term Energy Market Bids

STEM Bids reflect a decrease in generation or an increase in consumption. Figure 11 illustrates the daily average quantity of STEM Bids per Trading Interval for all Market Participants from market commencement until 31 July 2011.

Figure 11 Daily average quantity of STEM Bids (cumulative MWh per Trading Interval)



By design, the high level of Market Customer's bilateral commitment (in terms of its demand) will result in the volume of STEM Bids being lower than the volume of STEM Offers. This is evident in a comparison of Figure 11 and Figure 10.

As can be seen in Figure 11, significant quantities of energy have consistently been bid in the STEM between the Minimum STEM Price and $50/MWh. In the STEM's design this outcome would be expected – given it covers quantities already contracted and represents must-run[130] and lower cost capacities (such as coal fired generators) which can be expensive to shutdown and restart. Quantities have been bid at higher prices only infrequently.

STEM Bids for each Market Participant are set out separately in Figure 43 through Figure 57 in Appendix 3. These figures show clear differences in the prices and volumes at which Market Participants have bid quantities in the STEM.

As with STEM Offers, Verve Energy accounts for the largest volumes of STEM Bids.

5.2.1.5 Short Term Energy Market traded quantities

Although not required under the Market Rules, this section provides information on STEM traded quantities.

Table 5 shows the annual average of STEM traded quantity among Market Participants (cumulative MWh per Trading Interval) for four yearly periods since market commencement, as well as an overall average from market commencement to 31 July 2011.

Table 5 Annual average of Short Term Energy Market traded quantities among Market Participants (cumulative MWh per Trading Interval)

	21 Sep 06 - 31 Jul 07	1 Aug 07 - 31 Jul 08	1 Aug 08 - 31 Jul 09	1 Aug 09 - 31 Jul 10	1 Aug 10 - 31 Jul 11	Average quantity
STEM traded quantities	9.61	13.75	32.31	53.60	**64.39**	35.23

Note: 'Average quantities' are for the overall period, i.e., 21 September 2006 to 31 July 2011.

Figure 12 and Figure 13 show the daily average volume bought and sold in the STEM, respectively, for all Market Participants from market commencement to 31 July 2011.

The historical volume traded in the STEM remained relatively low until the commencement of the 2008/09 Capacity Year in October 2008. Since then traded volumes have increased substantially, which is largely attributed to the entry of NewGen and Griffin Power in that Capacity Year. Increased STEM trade volume carried on into the current Reporting Period and was driven primarily by a number of IPP's seeking to sell energy in the STEM, which included Alinta, Griffin Power and NewGen. As seen in Figure 12, the most significant buyers in the STEM in the current Reporting Period have been Synergy closely followed by Verve Energy.

Figure 13 shows that during the current Reporting Period the most significant sellers in the STEM during the current Reporting Period were Verve Energy and Alinta Sales.

[130] Generator co-located with, and providing steam to, an industrial plant.

Figure 12 Daily average quantities bought in the STEM (MWh)

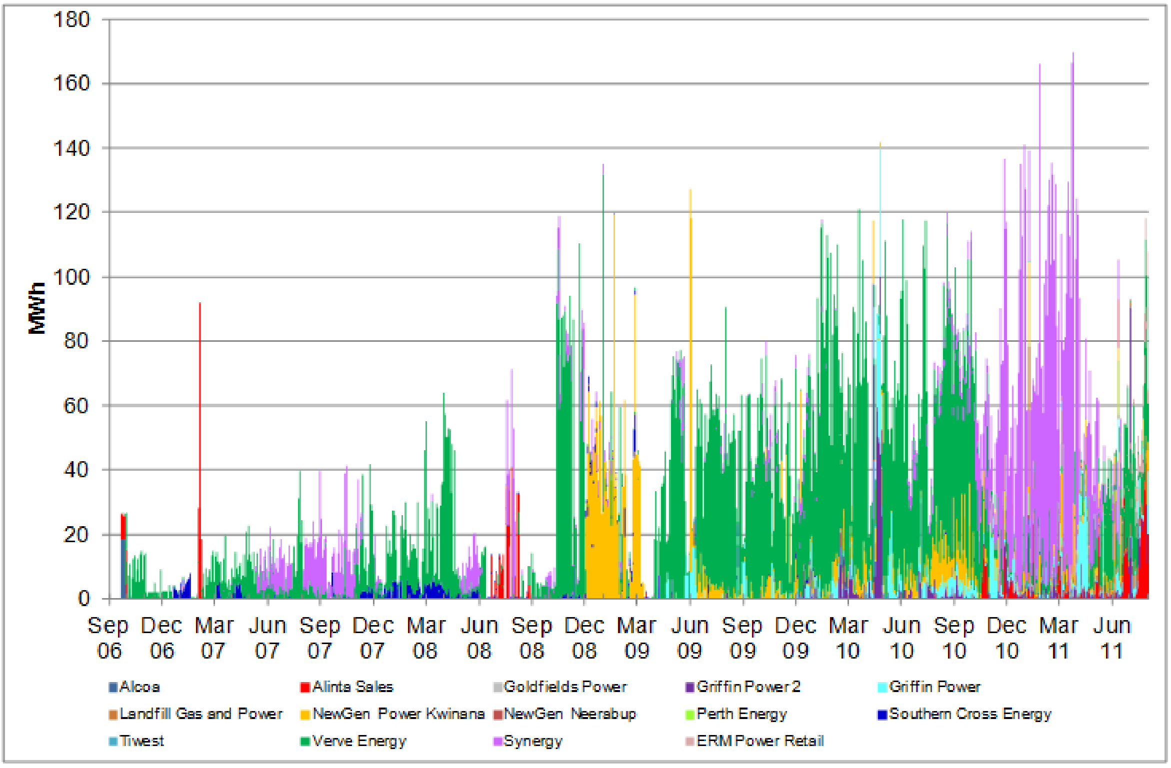


Figure 13 Daily average quantities sold in the STEM (MWh)

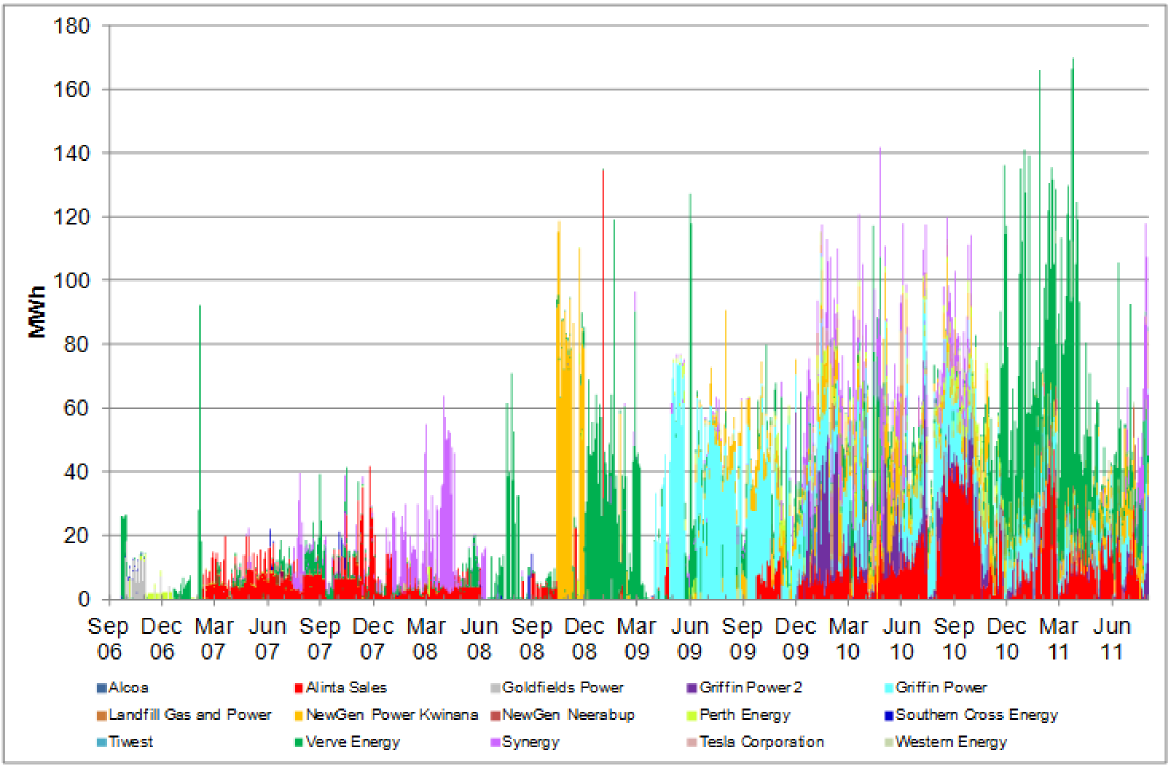


Figure 58 in Appendix 3 shows average daily STEM Clearing Quantities for each Trading Day from 21 September 2006 (market commencement) to the end of the current Reporting Period (31 July 2011), as well as 30-day, 90-day and annual moving average quantities.

5.2.2 Balancing

Clause 2.16.2(d) of the Market Rules requires that the MSDC includes the Balancing Data prices and other Standing Data prices used in balancing.

There is also a requirement under clause 2.16.4 to calculate:

- means and standard deviations of Balancing Data prices;
- monthly, quarterly and annual moving averages of Balancing Data prices;
- statistical analysis of the volatility of Balancing Data prices;
- the proportion of time that Balancing Data prices are at each price limit;
- the correlation between capacity available for Balancing and the incidence of high prices; and
- exploration of key determinants for high Balancing prices.

This section summarises the results of the requirements under both clause 2.16.2 and clause 2.16.4 of the Market Rules.

5.2.2.1 Balancing prices

Balancing enables Market Participants to adjust their Net Contract Position so that supply equals demand in real-time. Generally, System Management will match supply and demand in the system using Verve Energy's facilities. However, there are circumstances in which System Management can issue Dispatch Instructions to other Market Participants.

Standing Data prices used in Balancing

Where Market Participants other than Verve Energy are issued Dispatch Instructions by System Management, these deviations are settled on a pay-as-bid basis. The Standing Data prices used in Balancing consist of prices bid to increase or decrease supply by Market Participants other than Verve Energy.

The Standing Data prices used in Balancing are summarised in Figure 59 through to Figure 63 in Appendix 3, for the period from market commencement to 31 July 2011. These figures present average daily prices bid to increase and decrease consumption, by the type of facility: non-liquid generation, liquid generation, intermittent generation and Curtailable Loads.[131]

Broadly, IPPs want to be paid close to the applicable Maximum STEM Prices when instructed to increase generation from their Scheduled Generators irrespective of the time of the day. When instructed to reduce the level of generation, IPPs also want to be paid if a Non-Liquid generator is backed off, and are willing to pay either a low or high price (relative to distillate generation cost) for generation backed off from a Liquid Scheduled Generator.

[131] Curtailable Loads is a metered point through which electricity is consumed, where consumption can be curtailed at short notice.

In previous discussions with the Authority, the IMO has explained why some Market Participants have high increase and decrease supply prices.[132]

MCAP, UDAP and DDAP

In addition to Standing Data balancing prices, there are three other balancing prices determined by the IMO, being the:

- MCAP;
- Upwards Deviation Administered Price (**UDAP**); and
- Downwards Deviation Administered Price (**DDAP**).

MCAP is used to settle deviations from Net Contract Position[133] by Verve Energy, by Non-Scheduled Generators, by Non-Dispatchable, Interruptible and Curtailable Loads, and by non-Verve Energy Scheduled Generators.[134] In other words, rather than paying or receiving pay-as-bid prices for deviations, these facilities pay or receive MCAP for these deviations.

UDAP and DDAP are used to settle deviations outside a tolerance[135] for non-Verve Energy Scheduled Generators (excluding those subject to a test) that deviate from their schedules without instruction from System Management. UDAP is set at a discount to MCAP to discourage upward deviations without instruction from System Management and DDAP is set at a premium to MCAP to discourage downward deviations without instruction from System Management. The formula under the Market Rules for calculating UDAP and DDAP is set out in Table 11 in Appendix 3.

As with the analysis of STEM Clearing Prices, Balancing prices are summarised separately for peak and off-peak periods.

Table 6 sets out the mean and standard deviations of the peak and off-peak MCAP, UDAP and DDAP from:

- 21 September 2006 (i.e., market commencement) to 31 July 2011;
- 1 August 2009 to 31 July 2010 (i.e., the previous reporting period); and
- 1 August 2010 to 31 July 2011 (i.e., the current Reporting Period).

The patterns of Balancing prices broadly reflect the pattern of STEM Clearing Prices, with higher and more volatile prices during peak periods. This result is as expected, since the MCAP for a given Trading Interval (and, by extension, the UDAP and the DDAP for that Trading Interval) is based on STEM Bids and STEM Offers for that Trading Interval.

[132] See ERA website, 2009 Annual Wholesale Electricity Market Report for the Minister for Energy, http://www.erawa.com.au/cproot/8481/2/20100420 2009 Annual WEM Report to the Minister for Energy - Public Version.pdf, 18 February 2010, pp. 24-25.

[133] A Market Participant's Net Contract Position is its amount of contracted energy corresponding to its bilateral trades plus its STEM trades. In real-time, the actual energy provided may deviate from this Net Contract Position. The Balancing marker provides the means for trading these deviations.

[134] Subject to Commissioning Tests or tests of their RCRs, as well as within tolerance deviations in the output of these generators.

[135] As provided for under clause 6.17.9 of the Market Rules.

Table 6 **Mean and standard deviations of the MCAP, UDAP and DDAP ($/MWh)**

	Trading Interval	21 Sep 06 – 31 Jul 10		1 Aug 09 – 31 Jul 10		1 Aug 10 – 31 Jul 11	
		Mean	Std Dev	Mean	Std Dev	Mean	Std Dev
MCAP	Off-Peak	36.14	41.71	16.88	14.24	**26.48**	**22.82**
	Peak	75.52	78.69	42.38	27.91	**50.40**	**47.69**
UDAP	Off-Peak	0.00	0.00	0.00	0.00	**0.00**	**0.00**
	Peak	37.76	39.35	21.19	13.95	**25.20**	**23.85**
DDAP	Off-Peak	39.75	49.51	18.57	15.67	**29.13**	**25.10**
	Peak	97.41	98.53	55.09	36.29	**65.46**	**61.67**

Figure 14 and Figure 15 illustrate average daily peak and off-peak period Balancing prices for each Trading Day from market commencement to 31 July 2011. Because the UDAP and the DDAP are set with reference to the MCAP, there is a clear correlation between the three prices.

Following a period of high prices immediately after market commencement, both peak and off-peak Balancing prices were relatively stable in 2007 and the start of 2008, before increasing in the period following the Varanus Island incident in June 2008. Following the Varanus Island incident and the subsequent curtailment of gas supplies, Balancing prices increased significantly in June 2008 and remained at elevated levels for a number of months. Balancing prices returned to lower levels since that time, with average prices at or below those observed before the 2008 Varanus Island incident.

As can be seen in Figure 14, average peak period MCAP prices were significantly higher in mid-November 2010, mid January 2011, late February 2011, and late June to early July 2011.[136]

As can be seen in Figure 15, average off-peak period MCAP prices were significantly higher in late February and late June 2011.

[136] The high average peak period MCAPs during mid-November 2010 was a result of very high demand (exceeding 1,450 MWh) which also coincided with two major generation Facilities experiencing Forced Outages. During these high price Trading Days the maximum temperature ranged between 35.0°C and 40.5°C. Similarly the high MCAPs observed during mid-January 2011 were due to a major generation facility experiencing a Forced Outage. During the period late February 2011 (the week between 24 February and 2 March 2011) the gas supply interruption from Varanus Island caused by Cyclone Carlos resulted in very high MCAP prices both during peak and off-peak periods. The Authority observed that the normally-cheaper gas plants submitted expensive energy due to higher gas costs which resulted in higher MCAPs. The Authority also observed very high MCAPs for the period starting end of June 2011 to early July 2011. The large volume of Planned Outages allowed during high winter demand season contributed to periods of continuous high MCAPs, and Dispatch Instructions being issued for out of merit dispatching of IPP facilities at ‘pay as bid’ prices in order to mitigate the risk of liquid fuel usage and entering a High Risk System Operating State.

Figure 14 Average daily Peak Balancing prices

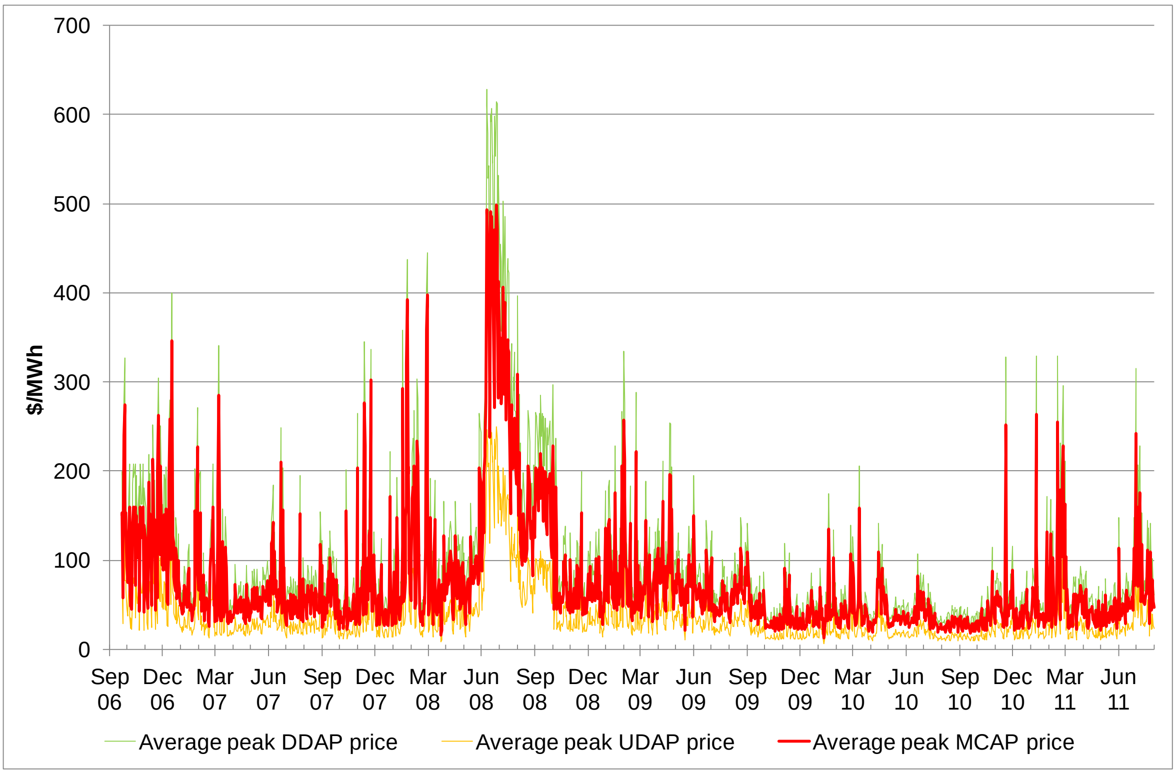
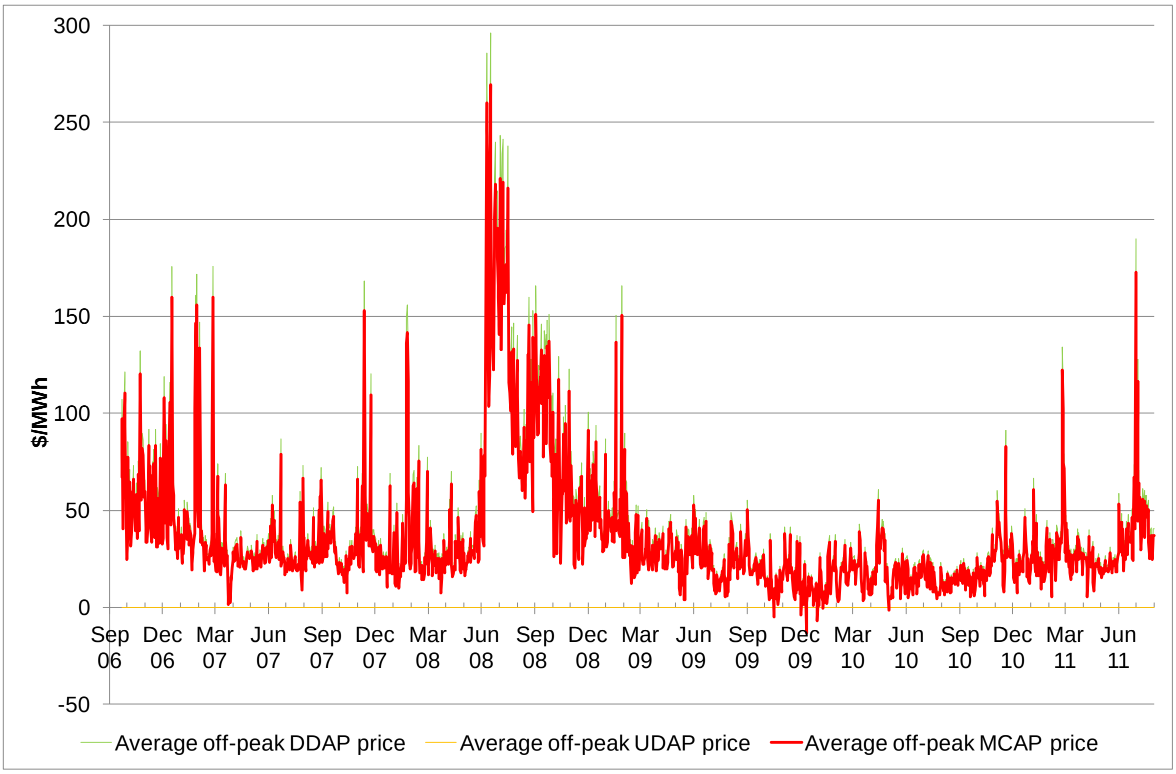


Figure 15 Average daily Off-Peak Balancing prices



The pattern of Balancing prices (i.e., MCAPs, DDAPs and UDAPs) during peak and off-peak periods is similar to the pattern of STEM Clearing Prices. This similarity is shown in Figure 64 and Figure 65 in Appendix 3, which compare 30-day and 90-day moving averages of peak STEM and Balancing prices, respectively.

As with peak periods, a strong correlation between off-peak Balancing prices and STEM Clearing Prices can be seen more clearly in Figure 66 and Figure 67 in Appendix 3, which compare the 30-day and 90-day moving averages of off-peak STEM and Balancing prices, respectively.

Figure 68 and Figure 69 in Appendix 3 show annual moving average STEM and Balancing prices for off-peak and peak periods, respectively.

5.2.2.2 Volatility of Balancing prices

As indicated by the price trends in Figure 3, Figure 4, Figure 14 and Figure 15, with the exception of a number of days in mid November 2010, mid January 2011 to early March 2011, and again in late June and early July 2011, the level and volatility of both STEM Clearing Prices and Balancing prices continue to be stable and at relatively low levels (i.e., since market commencement).

Volatility in Balancing prices is more accurately analysed by determining means and standard deviations. The means and standard deviations (as well as the maxima and minima) of Balancing prices are illustrated in Figure 70 through to Figure 74 in Appendix 3. In general, Peak Trading Interval Balancing prices are more volatile than Off-Peak Trading Interval prices for MCAP and DDAP, as was the case for STEM Clearing Prices. As with Off-Peak Trading Interval STEM Clearing Prices, the volatility of Off-Peak Trading Interval MCAPs and DDAPs has slightly increased in the current Reporting Period when comparing with the previous one. Peak MCAPs and DDAPs, as with peak STEM Clearing Prices, have also become more volatile in the current Reporting Period.

5.2.2.3 High Balancing prices

The Market Rules require an examination of both the incidence and causes of high Balancing prices.

As with STEM Clearing Prices, the incidence of high Balancing prices is examined by considering the proportion of time that Balancing prices are at the Energy Price Limits and by considering the price duration curve for Balancing prices.

Figure 16 illustrates the proportion of Peak Trading Intervals and Off-Peak Trading Intervals during which MCAPs were at the Maximum STEM Price. This shows that MCAPs were regularly at the Maximum STEM Price during Peak Trading Intervals in the summer months of the first years of the market, and also from June to September 2008 during the Varanus Island interruption. During the current and the previous reporting periods MCAPs reached the Maximum STEM Price for less than one per cent of total Peak Trading Intervals.

Comparing Figure 7 with Figure 16, it is clear that MCAPs were at the Maximum STEM Price more frequently than have STEM Clearing Prices in the earlier years of the market; however, during the Reporting Period, the occurrence of MCAPs (and STEM Clearing Prices) at the Maximum STEM Price have become very infrequent.

Figure 16 Proportion of Trading Intervals MCAPs at Maximum STEM Price (per calendar month)

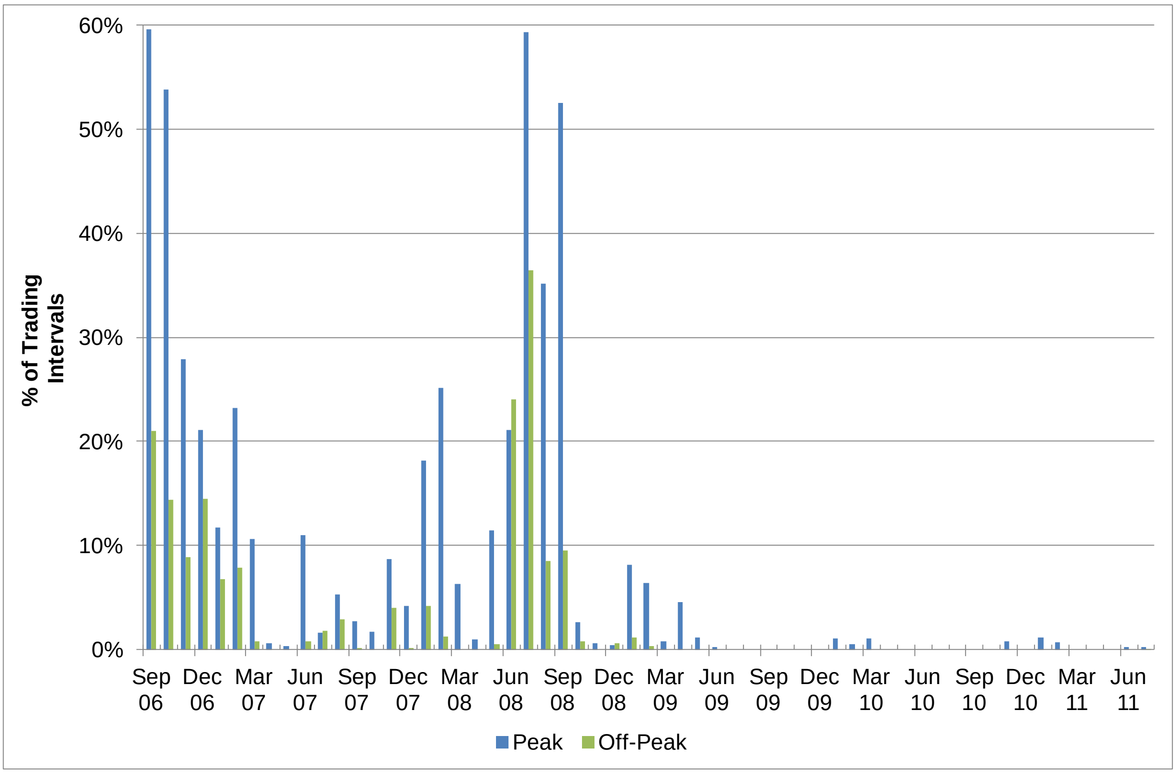


Figure 17 illustrates the proportion of peak and off-peak periods, during which MCAPs were at the Alternative Maximum STEM Price. As was the case in the previous reporting period, there were no instances of MCAPs reaching the Alternative Maximum STEM Price in the current Reporting Period. The last time MCAPs reached the Alternative Maximum STEM Price was in January 2008.

Figure 17 **Proportion of Trading Intervals MCAPs at Alternative Maximum STEM Price (per calendar month)**

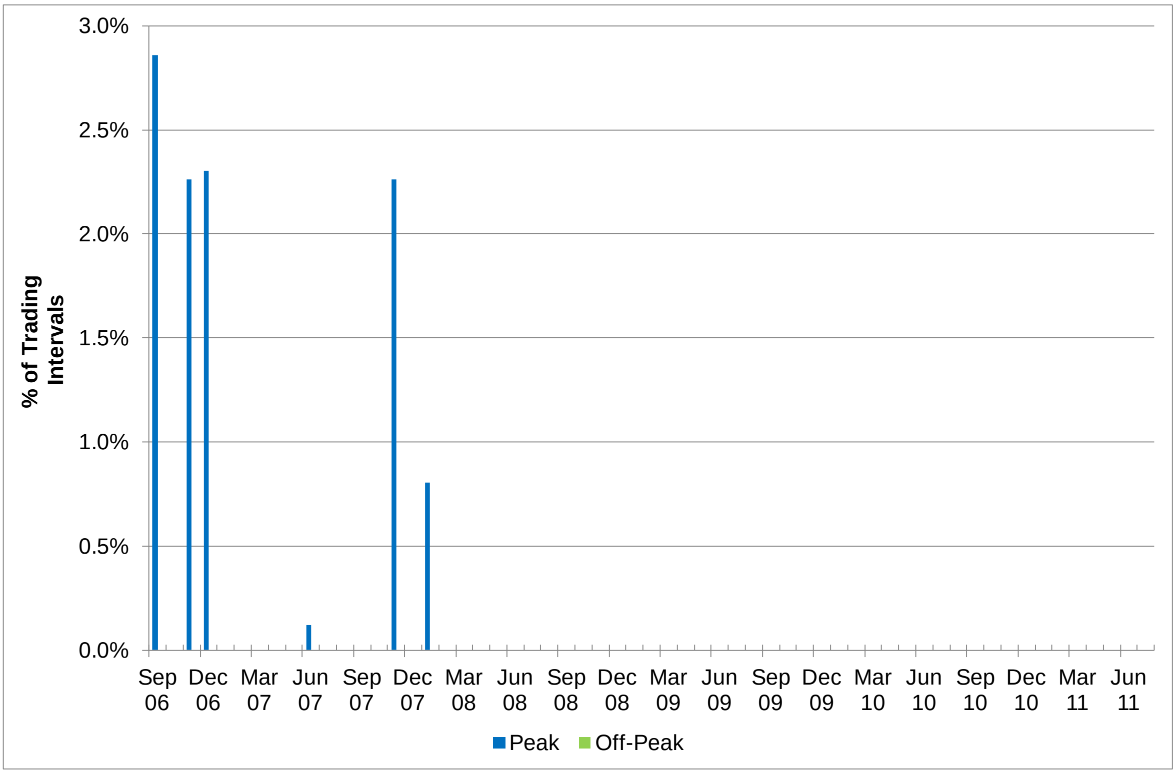


Figure 18 sets out the MCAP duration curve, covering all Trading Intervals from 21 September 2006 (market commencement) to 31 July 2011. For comparison, Figure 18 also includes the UDAP, DDAP and STEM price duration curves for the same period.[137] As expected, the MCAP is bounded by the UDAP and the DDAP.

As can be seen in Figure 18, the MCAP duration curve follows the price duration curve for STEM Clearing Prices relatively closely, although high MCAPs occur more frequently than high STEM Clearing Prices. A notable divergence between the MCAP and STEM Clearing Prices is at around $100/MWh, i.e., STEM Clearing Prices are less likely to be above $100/MWh than are MCAPs. This reflects the prior observation that MCAPs tend to be at the Maximum STEM Price more frequently than STEM Clearing Prices.

[137] Price duration curves for peak and off-peak period MCAPs are set out in Figure 75 and Figure 76 in Appendix 3, respectively.

Figure 18 **Price duration curves for STEM Clearing Prices, MCAPs, UDAPs and DDAPs (21 September 2006 to 31 July 2011)**

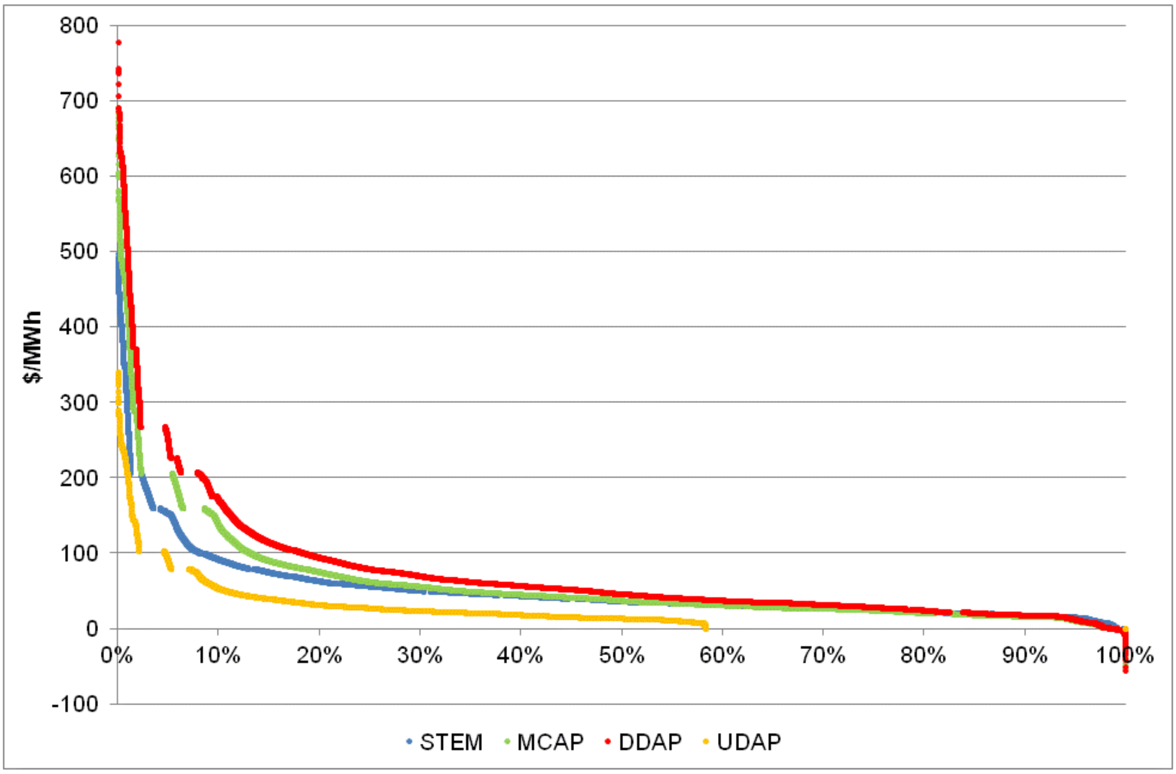


Figure 19 illustrates a comparison MCAP price duration curves for the periods 21 September 2006 (market commencement) to 31 July 2011, 1 August 2009 to 31 July 2010 and 1 August 2010 to 31 July 2011.

Figure 19 Comparison of price duration curves for MCAPs (past two annual reporting periods and 21 September 2006 to 31 July 2011)

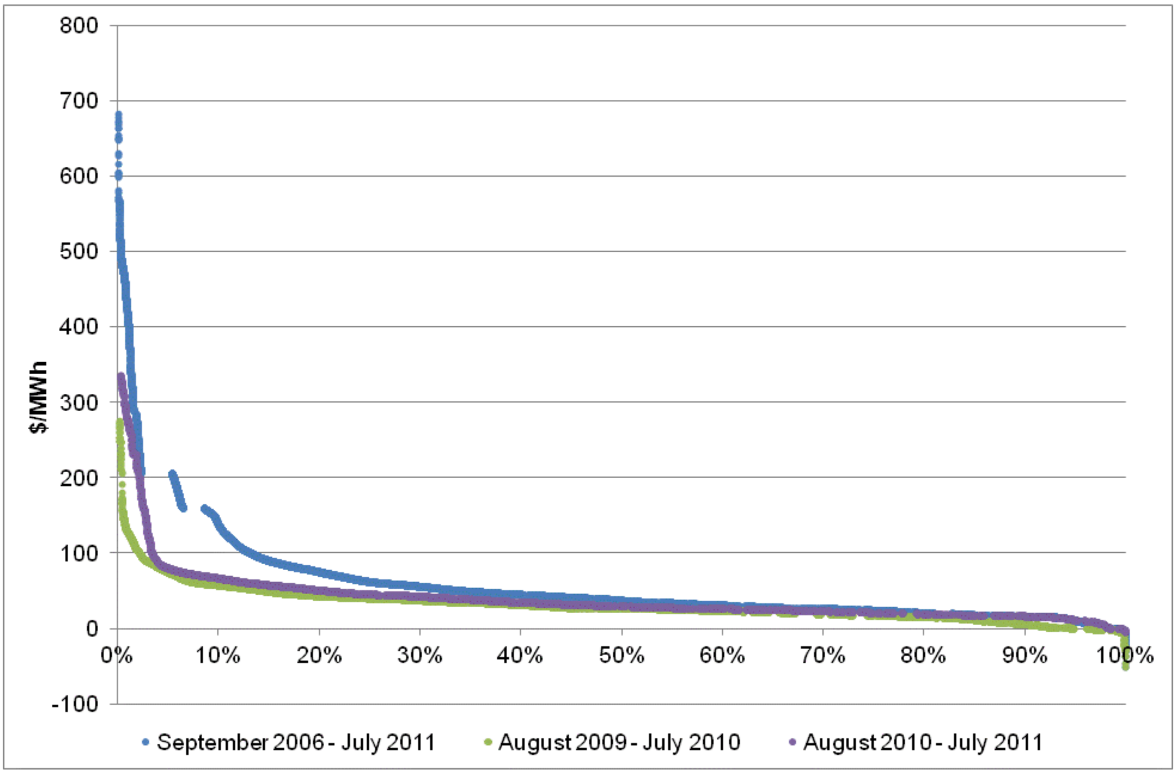


Figure 19 shows of the three periods examined, MCAPs were lowest during the previous reporting period (1 August 2009 to 31 July 2010). While MCAPs for the current Reporting Period remained at comparatively low levels, under $100/MWh for 96 per cent of the total Trading Intervals, MCAPs above $100/MWh averaged $213/MWh in the current Reporting Period, which compares to an average $139/MWh in the previous reporting period. The four-year average has MCAPs exceeding $100/MWh for 14 per cent of total Trading Intervals, and a maximum MCAP of $682/MWh, which was reached in July 2008 (i.e., shortly after the Varanus Island gas supply disruption).

Figure 77 and Figure 78 in Appendix 3 illustrate price duration curves for STEM Clearing Prices and MCAPs during peak Trading Intervals, for the reporting periods 1 August 2009 to 31 July 2010, and 1 August 2010 to 31 July 2011. A comparison of these figures shows the gap between STEM Clearing Prices and MCAPs during Peak Trading Intervals has increased significantly, particularly in the $100/MWh to $200/MWh price range.

Clause 2.16.4(f) of the Market Rules requires the calculation of the correlation between capacity available in Balancing and the incidence of high prices. When considering the correlation between STEM Clearing Prices and quantities offered into the STEM, the correlation between capacity available in Balancing and the incidence of high Balancing prices will fail to usefully capture key determinants of Balancing prices. Therefore, correlations are not included in this report. However, the Authority continues to work with the IMO on developing appropriate forms of analysis to explain the incidence of high Balancing prices. This is discussed in detail in Section 5.2.1.3.

In addition to analysing the key determinants of high prices in the STEM, clause 2.16.4(g) requires the IMO to explore the key determinants for high Balancing prices. As noted above, this is being considered on an ongoing basis jointly by the IMO and the Authority, and is discussed in Section 5.2.1.3.

5.2.2.4 Capacity available through Balancing (through Dispatch Instructions)

Clause 2.16.2(i) of the Market Rules requires that the MSDC identify the capacity available through Balancing from Scheduled Generators and Non-Scheduled Generators and Dispatchable Loads.

At this stage, the IMO calculates the capacity available through Balancing from Market Participants other than Verve Energy. This is because, in effect, all of Verve Energy's capacity is available to provide Balancing. The IMO derives the capacity available through Balancing from a facility as:

- the Facility capacity limit;
- less the Loss Factor adjusted generation for the Facility (as set out in the Resource Plan); and
- less quantities for the Facility set out in an Availability Declaration.

This information is confidential and is not presented in this public version of the report.

5.2.2.5 Number and frequency of Dispatch Instructions

Clause 2.16.2(j) of the Market Rules requires that the MSDC identify the frequency and nature of Dispatch Instructions to Market Participants other than Verve Energy.

Dispatch Instructions are issued by System Management to Market Participants other than Verve Energy, directing the participant to vary the output or consumption of one of its facilities from the level indicated in its Resource Plan, or to vary the output or consumption of one of its facilities holding Capacity Credits.

Figure 20 shows the total number of increment Dispatch Instructions and decrement Dispatch Instructions issued per Trading Day, from 21 September 2006 (market commencement) to 31 July 2011.[138]

During the current Reporting Period, the maximum numbers of Dispatch Instructions recorded per Trading Day were:

- 113 increment and 47 decrement on 25 February 2011;
- 268 increment on 26 February 2011; and
- increment and 715 decrement on 28 February 2011.

The issuance of these Dispatch Instructions coincided with the shutdown of gas supply production at Varanus Island due to the effects of Cyclone Carlos. This gas supply disruption affected generation in the SWIS and led to the declaration of a High Risk Operating State from 23 February 2011 until 1 March 2011. In order to manage the High Risk Operating State during this period, System Management issued the (above listed) increment instructions to Scheduled Generators to increase production over their Resource Plans, and the decrement instructions Demand Side Management providers to dispatch Curtailable Load.

[138] Note that this counts a System Management Dispatch Instruction that spans multiple Trading Intervals as multiple Dispatch Instructions.

Figure 20 Daily count of Dispatch Instructions (21 September 2006 to 31 July 2011)

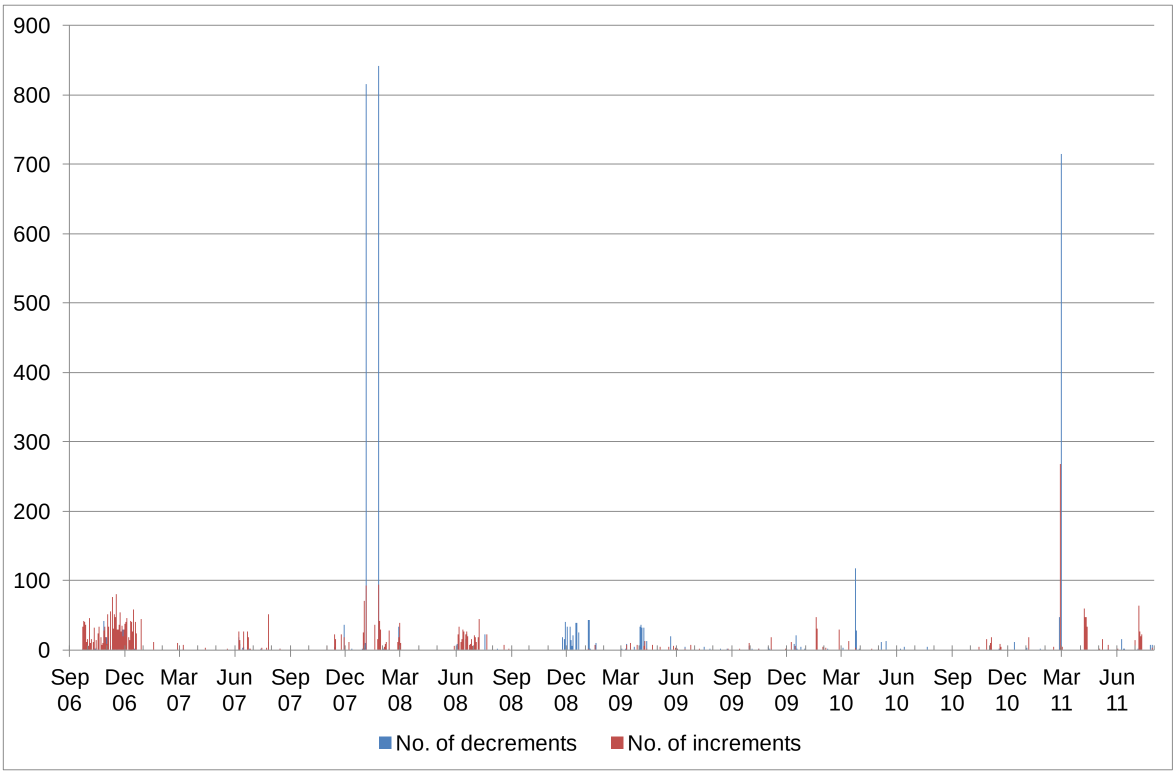
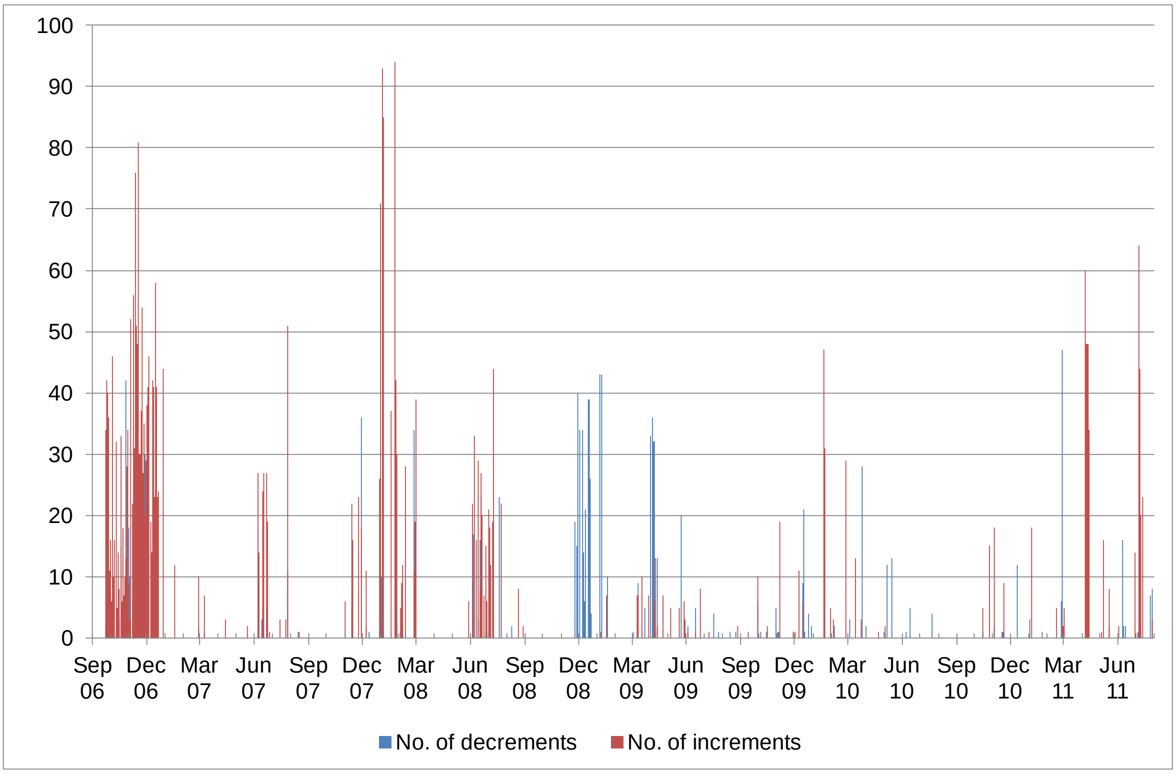


Figure 21 shows the total number of increment Dispatch Instructions and decrement Dispatch Instructions issued per Trading Day, from 21 September 2006 (market commencement) to 31 July 2011, with the outliers removed (i.e., increment or decrement Dispatch Instructions recorded per Trading Day above 100 in total).

Figure 21 Daily count of Dispatch Instructions - outliers removed (21 September 2006 to 31 July 2011)



5.3 Bilateral market

5.3.1 Bilateral quantities

Clause 2.16.2(e) of the Market Rules requires that the MSDC identify all bilateral quantities scheduled with the IMO.

Bilateral quantities scheduled with the IMO are classified as confidential information. In principle, information on bilateral quantities could be aggregated and included in this public version of the report. However, the majority of bilateral quantities are traded between Verve Energy and Synergy (albeit with a decreasing trend over the past three reporting periods), so that aggregation would not necessarily mask the data. As a result, information on the bilateral quantities scheduled with the IMO has not been presented in this public version of the report.

Nevertheless it can be noted that the total bilateral quantities scheduled with the IMO increased by approximately 11 per cent in the current Reporting Period in comparison to the previous reporting period (the average increase of total bilateral quantities scheduled with the IMO over the past three reporting periods – including the current Reporting Period – is approximately 7 per cent). Also, total bilateral quantities show a seasonal trend, with greater quantities and some spikes in quantities occurring during summer. A further discussion of the market for Bilateral Contracts for capacity and energy is included in section 4.3.

5.4 Retail sector

5.4.1 Number of customers changing retailer

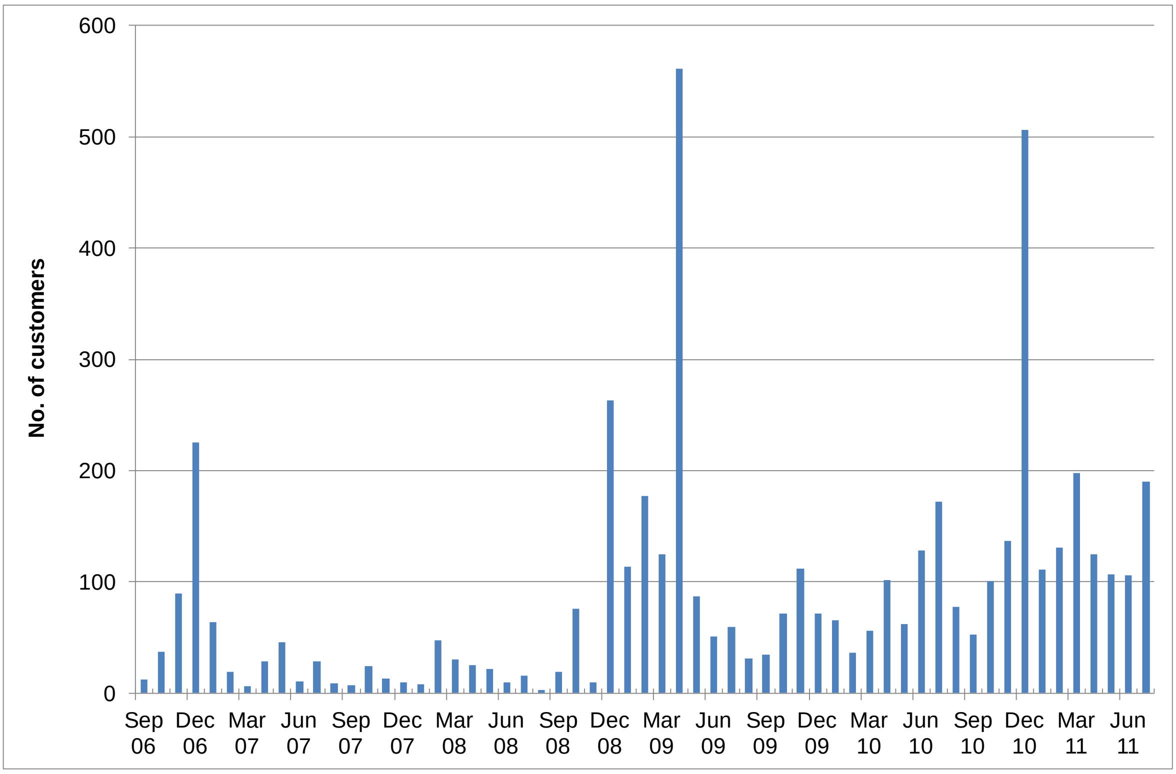
Although not required under the Market Rules, this section provides data on the rate at which customers have switched, or 'churned', between retailers from 21 September 2006 (market commencement) to 31 July 2011.

Figure 22 illustrates levels of customer transfer[139] in the contestable section of the electricity market in the SWIS since market commencement. Levels of customer transfer spiked in the first few months following market commencement, with 225 customers being transferred between retailers in December 2006. Customer transfer numbers then moderated and remained relatively low throughout 2007 and for the majority of 2008.

The general trend has been toward a steady increase in the number of customers changing retailers since December 2008, which likely reflects the Government's decision to increase tariffs in 2009. Notably, customer transfer numbers spiked in April 2009 (561 customers) and again in December 2010 (506 customers).

Outcomes in the retail market are also discussed in the Executive Summary of this report.

Figure 22 Number of customers changing retailer (customers per month)



[139] Customer churn is measured by the number of National Meter Identifiers (NMIs) transferred between retailers.

5.5 Surveillance items

5.5.1 Fuel Declarations

A Market Participant submitting a STEM Submission must include a Fuel Declaration.[140] clause 2.16.2(gA) of the Market Rules requires that the MSDC identify all Fuel Declarations. There is also a requirement under Clause 2.16.4(cA) of the Market Rules to calculate any consistent or significant variations between Fuel Declarations and the actual real-time operation of a Market Participant.

Table 7 summarises the Fuel Declarations for each dual fuel Facility, showing the percentage of all Trading Intervals for which each dual fuel Facility was assumed to be operating on Non-Liquid and Liquid Fuels, for the 2008/09 through 2010/11 Reserve Capacity Years. Dual fuel facilities tend to declare either liquid or non-liquid for the majority of the Trading Intervals for which they make a declaration, suggesting that dual fuel facilities have a primary fuel supply, with occasional use of a secondary fuel supply.[141]

In the 2010/11 Reserve Capacity Year, the Fuel Declarations for Alinta's Wagerup facilities were opposite to their declarations made for the 2009/10 Reserve Capacity Year, i.e., for approximately 70 per cent of the time these units were declared to be run on Non-Liquid Fuel as compared to approximately 37 per cent of the time during the previous capacity year. Another exception was Perth Energy's Kwinana facility which declared to run on Liquid Fuel for 99 per cent of the total time during the 2010/11 Reserve Capacity Year as compared to the six per cent of the time during the previous Reserve Capacity Year. A significant decrease, from 100 per cent last year to 36 per cent this year, was also observed in Alcoa's Wagerup facility Liquid Fuel declaration.

[140] See clause 6.6.1 of the Market Rules.

[141] Fuel Declarations for these facilities are influenced by the expected availability of gas, although Market Participants are not always aware of gas supply constraints at the time that they are required to make their STEM Submissions. This can result in variations between Fuel Declarations and the actual operation of a facility. The IMO monitors variations between Fuel Declarations and actual operation.

Table 7 Fuel Declarations (last three Capacity Years)

Participant	Resource Name	Liquid declaration 2008/09 Cap Year	Non-liquid declaration 2008/09 Cap Year	Liquid declaration 2009/10 Cap Year	Non-liquid declaration 2009/10 Cap Year	Liquid declaration 2010/11 Cap Year	Non-liquid declaration 2010/11 Cap Year
Alcoa	ALCOA_KWI	7.9%					
Alcoa	ALCOA_PNJ	7.9%					
Alcoa	ALCOA_WGP	98.9%		100.0%		36.7%	
Alinta	ALINTA _WGP_AGG					1.6%	20.8%
Alinta	ALINTA_WGP_GT	99.7%		62.7%	37.3%	8.3%	69.0%
Alinta	ALINTA_WGP_U2	98.4%	1.1%	62.6%	37.4%	6.9%	70.3%
Goldfields Power	PRK_AG	99.7%		100.0%		97.9%	1.8%
Perth Energy	PERTHENERGY_ KWINANA_GT1			6.3%		99.7%	
Southern Cross	STHRNCRS_EG	6.6%					
Verve Energy	KEMERTON_GT11		99.7%	0.3%	99.7%	1.1%	98.6%
Verve Energy	KEMERTON_GT12	69.9%	29.9%	0.8%	99.2%	1.1%	98.6%
Verve Energy	KWINANA_G3	0.8%					
Verve Energy	KWINANA_G4		25.2%				
Verve Energy	KWINANA_G5	0.3%	99.5%		100.0%	1.1%	98.6%
Verve Energy	KWINANA_G6	14.8%	84.9%		100.0%		99.5%
Verve Energy	KWINANA_GT1	99.7%		100.0%		99.7%	
Verve Energy	PINJAR_GT1		99.7%		100.0%	0.3%	99.5%

Participant	Resource Name	Liquid declaration 2008/09 Cap Year	Non-liquid declaration 2008/09 Cap Year	Liquid declaration 2009/10 Cap Year	Non-liquid declaration 2009/10 Cap Year	Liquid declaration 2010/11 Cap Year	Non-liquid declaration 2010/11 Cap Year
Verve Energy	PINJAR_GT2	99.5%	0.3%	100.0%		99.2%	0.6%
Verve Energy	PINJAR_GT3		99.7%		100.0%	0.6%	99.2%
Verve Energy	PINJAR_GT4	99.7%		100.0%		99.2%	0.6%
Verve Energy	PINJAR_GT5		99.7%		100.0%	0.6%	99.2%
Verve Energy	PINJAR_GT7	99.7%		100.0%		99.2%	0.6%

5.5.2 Availability Declarations

Clause 2.16.2(gB) of the Market Rules requires that the MSDC identify all Availability Declarations. There is also a requirement under Clause 2.16.4(cA) to calculate any consistent or significant variations between Availability Declarations and the actual real-time operation of a Market Participant's facility.

A Market Participant submitting a STEM Submission must include an Availability Declaration on net available energy.[142]

Figure 23 illustrates daily average Availability Declarations by Market Participant. Since the beginning of the 2007/08 Capacity Year, Availability Declarations have increased, principally from Verve Energy (which accounts for the majority of generating capacity in the market).

The Authority notes Verve Energy's unavailability declaration of approximately 56 MWh for the Muja G3 and Muja G4 units between April 2009 and 31 July 2011. The Authority understands that during this period these units were registered with the IMO but not capacity credited. This created a situation where Verve Energy needed to account for the capacity so it would not appear in the Dispatch Merit Order (**DMO**), which could have resulted in System Management attempting to dispatch these units when following the DMO. In order to achieve this, Verve Energy declared these units as unavailable through the STEM Submission's Availability Declarations mechanism.

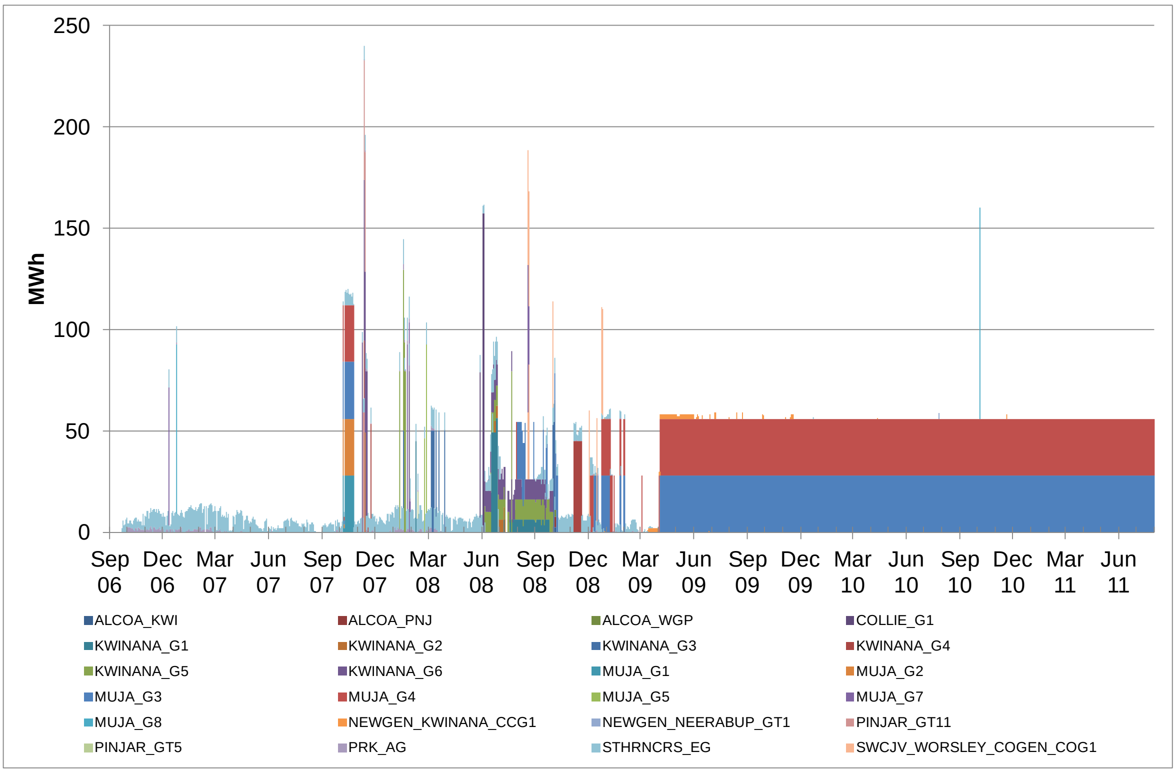
In the 2010 Report to the Minister it was noted that the reasons for Verve Energy's declarations regarding these two units did not appear to meet the requirements of making an Availability Declaration under the Market Rules (which takes account of any Ancillary Service Obligations or facility outages). Despite this, Verve Energy elected to continue to use the approach to avoid the potential for these units being dispatch by System Management.

The Authority notes that by mid-August 2012 Verve Energy had ceased its unavailability declaration for the Muja G3 and Muja G4 units (i.e., of approximately 56 MWh). The Authority also notes that:

- these units are a part of refurbishment of four coal-fired generating units at Muja power station (i.e., Muja G1 – Muja G4), which is a joint-venture between Verve Energy and Inalco (known as Vinalco);
- Vinalco registered with the IMO as a Market Generator in July 2009; and
- all four units (i.e., Muja G1 – Muja G4) are scheduled to be returned to service by the commencement of the 2012/13 Reserve Capacity Year in October 2012.

[142] See Clause 6.6.1 of the Market Rules. The Availability Declaration is to set out, for each Trading Interval and for each of the Market Participant's facilities, the difference between the energy available from the facility based on its Standing Data (adjusted to account for any energy committed to providing Ancillary Services and any energy unavailable due to outages reported by the IMO) and the energy assumed to be available from the facility in forming the Portfolio Supply Curve for the Trading Interval. Only quantities greater than zero need to be reported in the Availability Declaration.

Figure 23 Daily average Availability Declarations (MWh unavailable per Trading Interval)



Significant variations between Availability Declarations and the actual real-time operation of a Market Participant are assessed by comparing:

- the remaining capacity available after taking into account quantities declared in an Availability Declaration, with
- the total (Loss Factor-adjusted) quantity supplied, as measured by System Management's Supervisory Control and Data Acquisition (**SCADA**) system.

If, on the basis of this comparison, the remaining capacity available is less than the quantity supplied, this indicates that a Facility has been available to supply the market to a greater extent than was indicated in the STEM Submission for that Facility. The significance of this statistic is to detect if a Market Participant falsely declares that a low cost capacity is unavailable. By leaving out low cost capacity the Market Participant will be able to put in a submission with a higher cost schedule. This could result in a higher STEM Clearing Price. The Market Participant could then generate with the low cost capacity which is truly available and make an excessive profit.

Significant variations between Availability Declarations and the actual real-time operation has been determined for each facility in the market, but the information is commercially sensitive and so is not presented in this public version of the report.

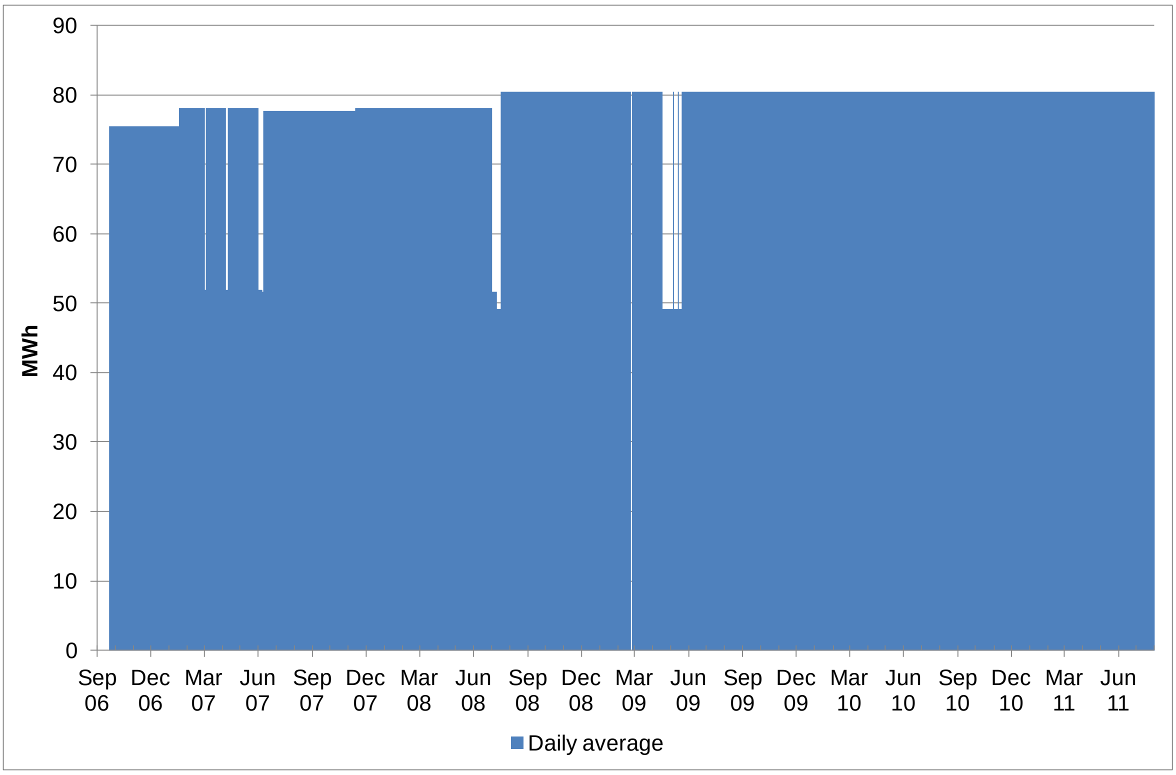
5.5.3 Ancillary Service Declarations

A Market Participant that is a provider of Ancillary Services must include an Ancillary Services Declaration in its STEM Submission.[143] Clause 2.16.2(gC) of the Market Rules requires that the MSDC identify all Ancillary Service Declarations. There is also a requirement under clause 2.16.4(cA) of the Market Rules to calculate any consistent or significant variations between Ancillary Service Declarations and the actual real-time operation of a Market Participant.

Figure 24 shows that the only Market Participant to submit an Ancillary Service Declaration has been Verve Energy, with the average quantities of Ancillary Services fairly consistent at 80 MWh per Trading Interval for the current Reporting Period.[144]

As Verve Energy is the only Market Participant to submit an Ancillary Service Declaration, to date there has been no analysis of significant variations between declarations and the actual outcomes. In the event that other Market Participants begin to provide Ancillary Services, the Authority will commence reporting on variations between declarations and the actual real-time operation of facilities in future reports to the Minister.

Figure 24 Daily average Ancillary Services declarations (MWh per Trading Interval)



[143] See Clause 6.6.1. The Ancillary Services declaration is to set out the MWh of energy, from both liquid and non-liquid facilities that the Market Participant has not included in the Portfolio Supply Curve because it expects to have to maintain surplus capacity with which to provide Ancillary Services.

[144] The decreases in Ancillary Service Declarations from May to July 2008, and from April to May 2009 were due to Collie Power Station being on outage during those times.

5.5.4 Variations in Short Term Energy Market Offers and Bids

Clause 2.16.2(h) of the Market Rules requires that the MSDC identify any substantial variations in STEM Offers and STEM Bid prices or quantities relative to recent past behaviour.

The prices and quantities of STEM Offers and STEM Bids by each Market Participant are illustrated in Figure 29 through Figure 57 in Appendix 3. As has been observed in previous Reports to the Minister, there are significant variations in the prices and/or quantities of offers and bids of all Market Participants. In many cases, these variations occur both in the short-term (day-to-day) and longer term (since market commencement).

Significant variations in STEM Offers and STEM Bids present difficulties in the development of a robust system for identifying substantial variations relative to recent past behaviour. Development of a robust system requires conceptual issues to be addressed: including what constitutes a 'substantial variation' in prices or quantities and the definition of 'recent past behaviour'. The resolution of these two will impact on the variations that are required to be identified by the MSDC.

In attempting to track how a Market Participant STEM offers and bids change over time the IMO has defined a variable summarising the participant offers for a Trading Interval into a single number and similarly for bids. The Authority has been provided with a record of this variable for each of the Market Participants since market commencement. Given the challenges in the conceptual issues identified, the Authority will continue to examine how this variable could be used, as well as explore other methods of analysis, to satisfy the requirement under clause 2.16.2(h) of the Market Rules.

5.5.5 Evidence of Market Customers overstating consumption

Clause 2.16.2(hA) of the Market Rules requires that the MSDC identify any evidence that a Market Customer has significantly over-stated its consumption, as indicated by its Net Contract Position, with a regularity that cannot be explained by a reasonable allowance for forecast uncertainty or the impact of loss factors.

In order to identify whether a Market Customer has significantly overstated its consumption, it is necessary to determine both the Market Customer's planned load and actual load in accordance with the following.

- Planned load is determined in a different way for stand-alone Market Customers and Market Customers that are also Market Generators.
- For stand-alone Market Customers, planned load is measured as its Net Contract Position.
- For Market Customers that are also Market Generators, planned load is measured as demand as set out in the Market Customer's Resource Plan. The reason that Net Contract Position does not provide a useful measure of planned load for Market Customers that are also Market Generators is that these participants are able to meet their own demand using their own generation facilities, so that this demand will not be reflected in their Net Contract Position.
- Actual load is determined on the basis of settlement quantities for a Market Customer. This provides a measure of real-time load, taking into account any Dispatch Instructions.

The extent to which a Market Customer over-states its consumption is determined by calculating planned load less actual load. If planned load less actual load is positive, this indicates that the Market Customer has over-stated its consumption. If planned load less actual load is negative, this indicates that the Market Customer has under-stated its consumption. To understand the extent of any over-statement or under-statement, it is also useful to determine any over-stated or under-stated amount as a proportion of planned demand.

This information is confidential and is not presented in this public version of the report.

5.5.6 Number and frequency of outages

Clause 2.16.2(k) of the Market Rules requires that the MSDC identify the number and frequency of outages of Scheduled Generators and Non-Scheduled Generators, and Market Participants' compliance with the outage scheduling process.

Figure 25 illustrates the daily average number of units subject to Planned Outages per Trading Interval.

Figure 25 Number of Planned Outages (cumulative daily average per Trading Interval)

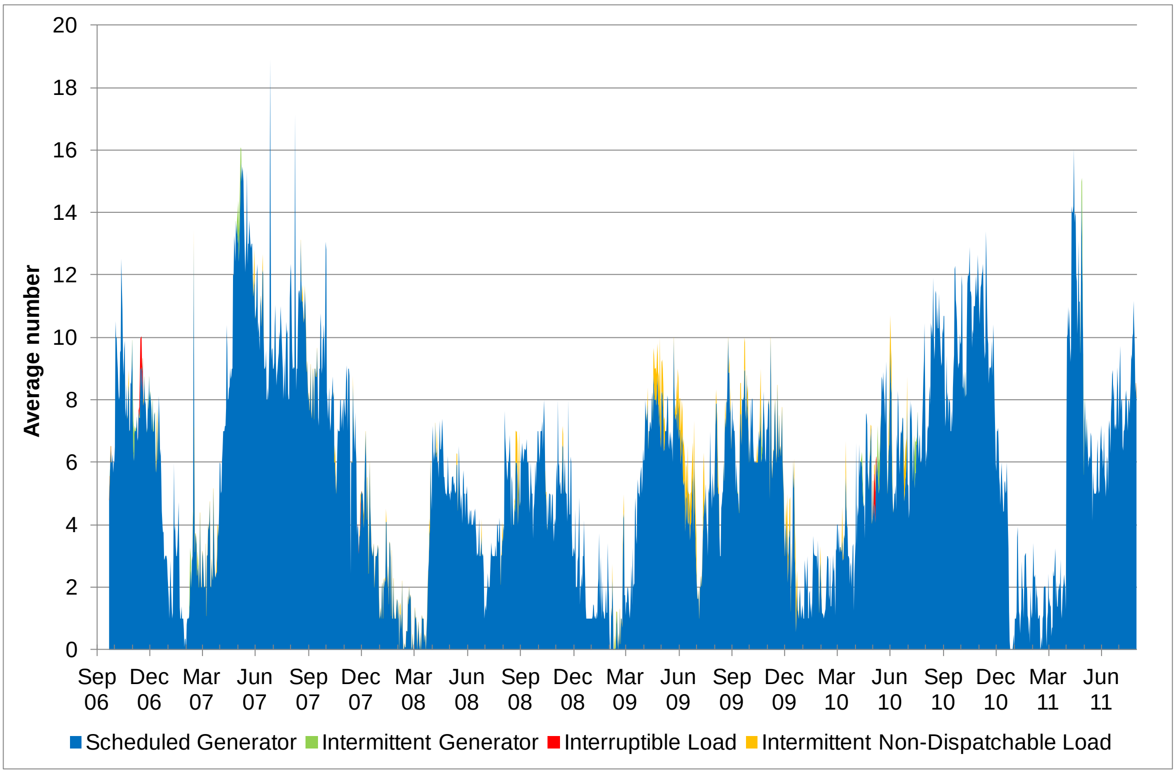


Figure 26 illustrates the accompanying MWh quantity of Planned Outages. As in previous years, it is clear from Figure 25 and Figure 26 that Planned Outages tend not to occur during December, January, February and March, in line with the low level of reserve margins prevailing at these peak demand times. The number of Planned Outages was significantly high during December 2010 as compared to the month of December in previous years. A number of Verve Energy's facilities were on Planned Outage for the majority of the month and a few Planned Outage of Griffin Power facility. The period between April and July had an increased number of Planned Outage as compared to the similar period of the previous years, with April 2011 recording maximum number of Planned Outages for the current Reporting Period. The Authority observed an overall increase in the number of Planned Outages for the current Reporting Period, except for the period between January and March 2011. A large number of Planned Outages comprised of coal-run facilities not available to the market for the longer periods. The Authority is also concerned if the large number of Planned Outages impact on the economic efficiency of the market.

Table 3 provides the information on each Facility's capacity subject to outages relative to the Facility's maximum generating capacity.

Figure 26 Quantity of energy subject to Planned Outage (cumulative daily average MWh per Trading Interval)

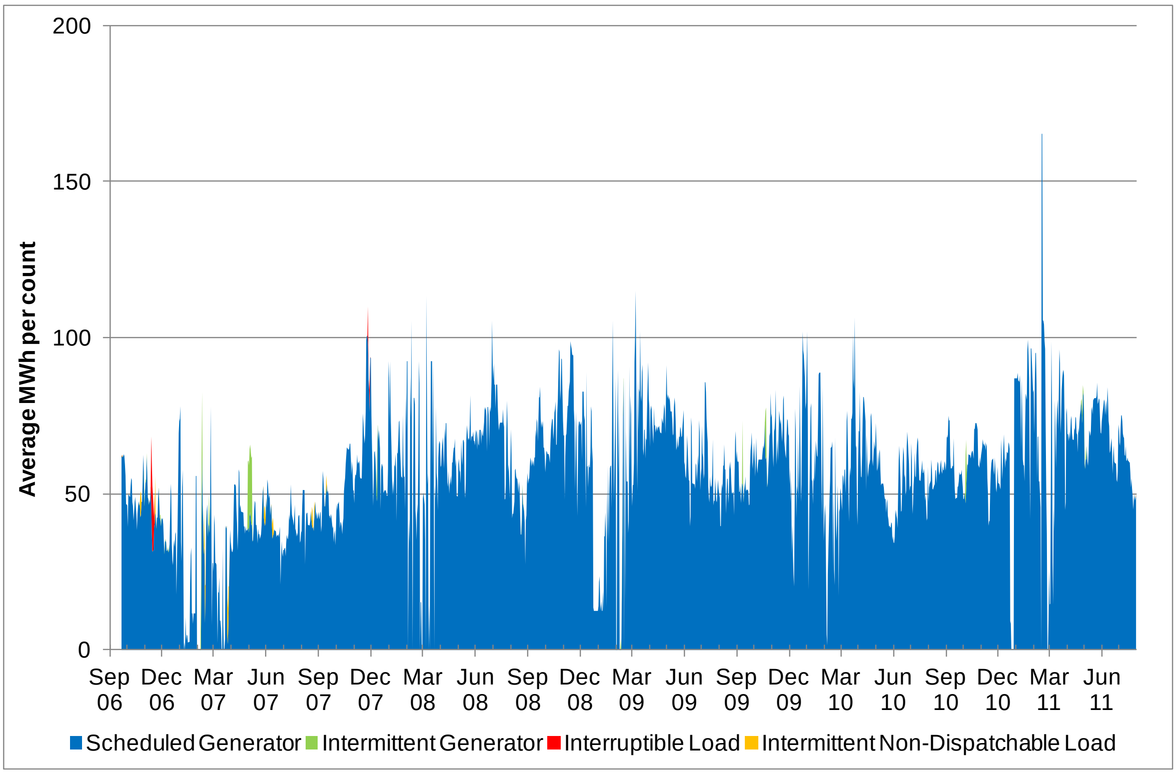


Figure 27 illustrates the daily average number of units subject to Forced Outages per Trading Interval.

Figure 27 Number of Forced Outages (cumulative daily average per Trading Interval)

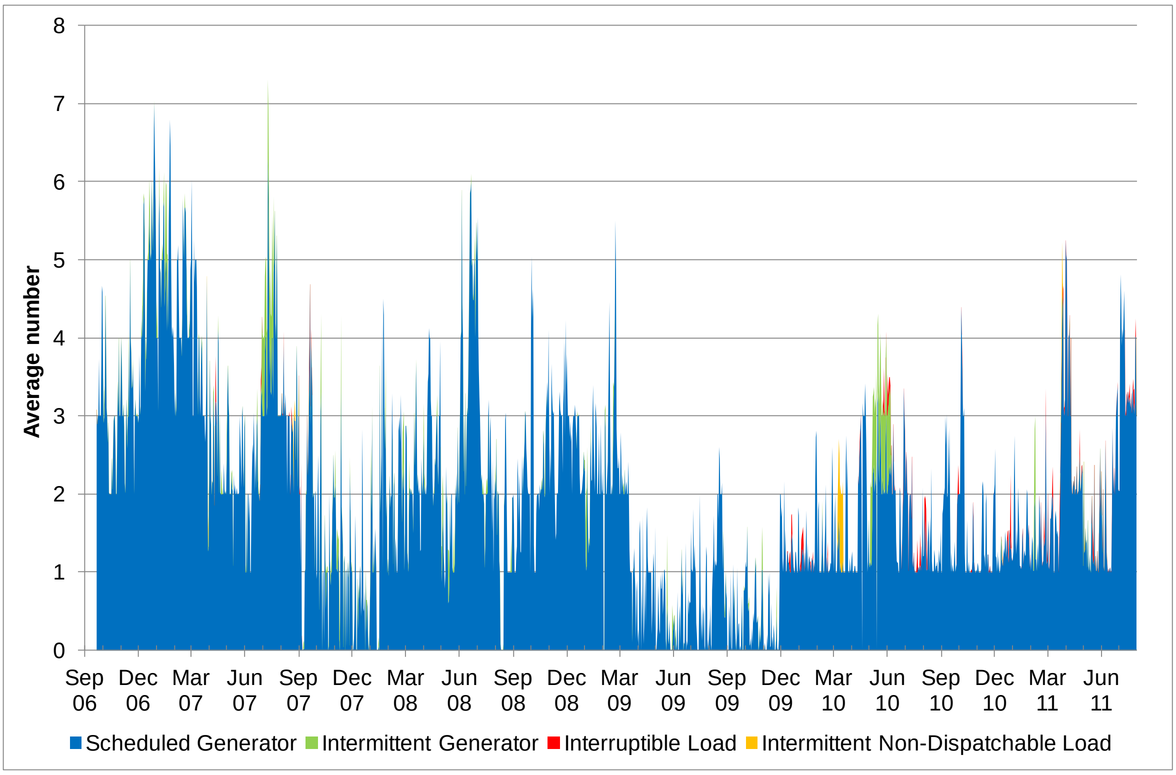
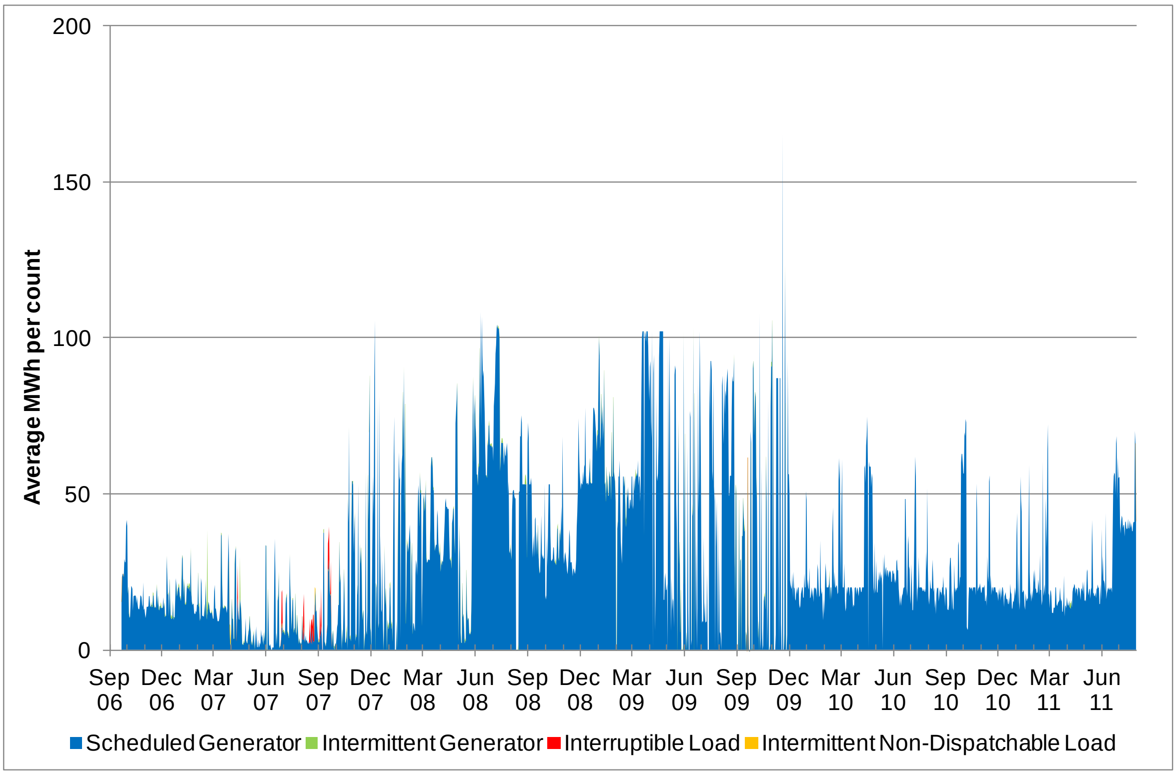


Figure 28 illustrates the accompanying MWh quantity of Forced Outages. As would be expected, there is no clear seasonal pattern for Forced Outages.

The overall Forced Outages for the current Reporting Period are quite low as compared to the first years of the market. For the majority of the current Reporting Period, the average number of Forced Outages remained under two per day. During the first week of October 2010 the number of Forced Outages averaged four per day, of which three of the Verve Energy's facilities were on Forced Outage. The average number of Forced Outages was high for the entire month of July 2011 with Griffin Power and Verve Energy's units on Forced Outage. Also IPP's like Goldfields Power and Alcoa had Forced Outages for short periods during the end of March 2011. No major Forced Outages were observed during the current Reporting Period for Intermittent Generators, Interruptible Loads and Intermittent Non-Dispatchable Loads.

The maximum average quantity for Forced Outages reached up to 75 MWh when Verve Energy's Muja and Pinjar facilities went on Forced Outages in the first week of October 2010. From the last week of June 2011 until the second week of July 2011 the average quantity of Forced Outages exceeded 50 MWh due to Verve Energy's Muja facility and Griffin Power's facility were on Forced Outage. The average Forced Outages quantities remained under 50 MWh for the majority of the current Reporting Period.

Figure 28 Quantity of energy subject to Forced Outage (cumulative daily average MWh per Trading Interval)



5.5.7 Key determinants of high prices in the Short Term Energy Market and Balancing

Clause 2.16.4(g) requires the IMO to explore the key determinants for high prices in the STEM and balancing. The Authority reported last year that it would work together with the IMO to develop the most appropriate approach for undertaking this analysis. The Authority is continuing to work with the IMO to develop appropriate forms of analysis to explain the incidence of high Balancing prices. This matter is further discussed in section 5.2.1.3.

5.6 Other information

5.6.1 Number of Market Generators and Market Customers

Clause 2.16.2(a) of the Market Rules requires that the MSDC identify the number of Market Generators and Market Customers in the WEM.

As at 3 October 2011 the following participants were registered with the IMO.

- 31 entities registered as Market Generators only. There are 10 new participants in this category compared to when last reported on 14 October 2010. These new participants are Blair Fox Pty Ltd, Merredin Energy, Mt. Barker Power Company Pty Ltd, Mumbida Wind Farm Pty Ltd, Tesla Corporation Management Pty Ltd, Tesla Geraldton Pty Ltd, Tesla Holdings, Tesla Kemerton Pty Ltd, Tesla Northam Pty Ltd and Walkaway Wind Power Pty Ltd.
- 12 entities registered as Market Customers only. There is no change in this category compared to when last reported on 14 October 2010.

- 10 entities registered as both Market Generators and Market Customers (Tiwest is the new registered participant in this category compared to when last reported on 14 October 2010).

This is a total of 51 registered entities and represents an increase from 15 entities at market commencement, 30 entities as at 2 September 2008, 36 as at 6 October 2009 and 42 as at 14 October 2010. Table 12 in Appendix 3 provides a list of these participants at 2 September 2008, 6 October 2009, 14 October 2010 and 3 October 2011.

In addition to these Market Generators and Market Customers, there are other classes of Market Participants. As at 3 October 2011, there were two entities registered as Network Operators: Western Power and Alinta Sales Pty Ltd.

5.6.2 Ancillary Service Contracts and Balancing Support Contracts

Clause 2.16.2(m) of the Market Rules requires that the MSDC identify details of Ancillary Service Contracts and BSCs that System Management enters into.

During 2010/11, 52MW of Spinning Reserve Ancillary Service was provided by interruptible load supplied by two non-Verve Energy Market Participants. This reduced to 42MW in October 2010 after the contract to supply 10MW from one supplier expired. The remaining Spinning Reserve Ancillary Service was supplied by synchronising additional Verve Energy generators. There was sufficient Verve Energy plant to meet this requirement even with the largest spinning reserve provider unit (a large open cycle gas turbine) is out of service.

In addition, System Management currently has a deed of undertaking with Verve Energy for the provision of Dispatch Support Ancillary Services in the Eastern Goldfields and North Country (Mungarra and Geraldton) regions. Verve Energy facilities at Mungarra, West Kalgoorlie and Geraldton supply these Dispatch Support Ancillary Services. The use of the Kalgoorlie Gas Turbines increased significantly due to a six-day outage of the Muja-Kalgoorlie 220kV transmission line in April 2011. The forecasted Dispatch Support Ancillary Services for 2011/12 will continue to be supplied from Verve Energy facilities as System Management did not at the time anticipate entering into further arrangements for dispatch support.

System Management also had an Ancillary Service contract with Verve Energy for the supply of System Restart Ancillary Services from three geographically dispersed Verve Energy sites in the SWIS which expired on 30 June 2011. As a result, System Management undertook a competitive tender process for procuring the System Restart Ancillary Service required in the three sub-networks to be commenced on 1 July 2011. The Authority notes that System Management competitively procured System Restart Services for two sub-networks for a five year term, while it directly negotiated a fee for service for the third sub-network for a two year term. The Authority determined the revised value for System Restart Ancillary Service for the 2011/12 and 2012/13 financial years as $40,933 per month and $41,583 per month respectively.

System Management has not entered into any BSCs between 21 September 2006 (market commencement) and 31 July 2011. Since market commencement, Verve Energy has been principally responsible for providing Balancing for the market.

5.6.3 Rule Change Proposals

Clause 2.16.2(o) of the Market Rules requires that the MSDC identify the number of Rule Change Proposals received, and details of Rule Change Proposals that the IMO has decided not to progress under Clause 2.5.6.

The formal Rule change process under the Market Rules commenced on 15 December 2006.

Prior to this, the Office of Energy was responsible for administering the Rule change process on behalf of the Minister for Energy. Between market commencement and 15 December 2006, the Office of Energy received 14 Rule Change Proposals, 12 of which were approved, and one of which was deferred until the formal Rule change process commenced. There was only one Rule Change Proposal that the Office of Energy did not recommend to the Minister for Energy for approval.[145]

Information on Market Rule changes that have commenced, been rejected or are under development is available on the IMO's website. Based on this information, Table 8 shows the IMO's progression of Rule Change Proposals since the commencement of the formal Rule change process.

Table 8 Progression of Rule Change Proposal since market commencement

Date range	Received	Commenced	Not progressed	Rejected	Under development
15 December 2006 and 31 July 2007	9	9[146]	-	-	-
1 August 2007 and 31 July 2008	36	36[147]	-	-	-
1 August 2008 and 31 July 2009	37	24[148]	-	3	10
1 August 2009 and 31 July 2010	19	15[149]	2	1	1
1 August 2010 and 31 July 2011	29	25[150]	2	-	2

[145] This was Rule Change Proposal CR2, submitted by Verve Energy, which proposed that the Maximum STEM Price be set equal to the Alternative Maximum STEM Price.

[146] As at the end of the 2007 calendar year.

[147] All of which have commenced.

[148] As at the time the 2009 Report to the Minister was released.

[149] As at the time the 2010 Report to the Minister was released.

[150] As at the time the 2011 Report to the Minister was released.

APPENDICES

Appendix 1 The Authority's reporting requirements under the Market Rules and the related sections in this report

Reporting Requirements under the Market Rules

The Market Rules require the Authority to provide to the Minister for Energy a report on the effectiveness of the market in meeting the Wholesale Market Objectives, and set out specific reporting requirements for the Authority.

Clause 2.16.11 of the Market Rules sets out a requirement for the Report to the Minister to report on the effectiveness of the market in dealing with the matters identified in clauses 2.16.9 and 2.16.10 of the Market Rules.[151]

Clause 2.16.9 of the Market Rules declares that the Authority is responsible for monitoring the effectiveness of the market in meeting the Wholesale Market Objectives, and that the Authority must investigate any market behaviour that has resulted in the market not functioning effectively. The Authority, with the assistance of the IMO, must monitor:

- Ancillary Services Contracts and Balancing Support Contracts;
- instances of inappropriate and anomalous market behaviour (in relation to bidding in the STEM and Balancing, as well as in the making of Availability Declarations, Ancillary Services Declarations and Fuel Declarations);
- market design problems or inefficiencies; and
- problems with the structure of the market.

Clause 2.16.10 of the Market Rules sets out that the Authority must review the effectiveness of:

- the Market Rule change process and Procedure change process;
- the compliance monitoring and enforcement measures in the Market Rules and Regulations;
- the IMO in carrying out its functions under the Regulations, the Market Rules and Market Procedures; and
- System Management in carrying out its functions under the Regulations, the Market Rules and Market Procedures.

Clause 2.16.12 of the Market Rules sets out further requirements for the Report to the Minister, as follows:

- a summary of the information and data compiled by the IMO and the Economic Regulation Authority under clause 2.16.1;
- the Economic Regulation Authority's assessment of the effectiveness of the market, including the effectiveness of the IMO and System Management in carrying out their functions, with discussion of each of:
    - o the Reserve Capacity market;

[151] Pursuant to clause 2.16.11 of the Market Rules, the report must be produced at least annually, or more frequently where the Authority considers that the WEM is not effectively meeting the Wholesale Market Objectives.

- the market for Bilateral Contracts for capacity and energy;
- the Short Term Energy Market;
- Balancing;
- the dispatch process;
- planning processes; and
- the administration of the market, including the Market Rule change process;

- an assessment of any specific events, behaviour or matters that impacted on the effectiveness of the market; and
- any recommended measures to increase the effectiveness of the market in meeting the Wholesale Market Objectives to be considered by the Minister.

Reporting requirements mapped to the sections of this report

Table 9 Mapping of the reporting requirements under the Market Rules to report sections

Market Rule clause	Market Rule reporting requirement	See report section
2.16.9 (a)	Monitoring of Ancillary Services Contracts and Balancing Support Contracts	3.1
2.16.9 (b)	Monitoring of inappropriate and anomalous market behaviour	3.2
2.16.9 (c)	Monitoring of market design problems or inefficiencies	3.3
2.16.9 (d)	Monitoring of problems with the structure of the market	3.4
2.16.10 (a)	Effectiveness of the Market Rule change process and Procedure change process	4.1.1
2.16.10 (b)	Effectiveness of the compliance monitoring and enforcement measures in the Market Rules and Regulations	4.1.2
2.16.10 (c)	Effectiveness of the IMO in carrying out its functions under the Regulations, the Market Rules and Market Procedures	4.1.3
2.16.10 (d)	Effectiveness of System Management in carrying out its functions under the Regulations, the Market Rules and Market Procedures	4.1.3
2.16.12 (a)	Summary and analysis of the Market Surveillance Data Catalogue	5
2.16.12 (b)	Effectiveness of the market	4
2.16.12 (b) i.	Effectiveness of the Reserve Capacity market	4.2
2.16.12 (b) ii.	Effectiveness of the market for Bilateral Contracts for capacity and energy	4.3
2.16.12 (b) iii.	Effectiveness of the Short Term Energy Market	4.4
2.16.12 (b) iv.	Effectiveness of Balancing	4.55
2.16.12 (b) v.	Effectiveness of the dispatch process	4.66
2.16.12 (b) vi.	Effectiveness of planning processes	4.67
2.16.12 (b) vii.	Effectiveness of the administration of the market, including the Market Rule change process	4.1 and 4.1.1
2.16.12 (c)	Assessment of any specific events, behaviour or matters that impacted on the effectiveness of the market	2
2.16.12 (d)	Any recommended measures to increase the effectiveness of the market in meeting the Wholesale Market Objectives to be considered by the Minister	2 and the Executive Summary

Table 10 Mapping of the MSDC data and analysis requirements under the Market Rules to report sections

Market Rule clause	Market Rule reporting requirement	See report section
2.16.2(a)	The number of Market Generators and Market Customers in the market	5.6.1
2.16.2(b)	The number of participants in each Reserve Capacity Auction	5.1.1
2.16.2(c)	Clearing prices in each Reserve Capacity Auction and STEM Auctions	5.1.3
2.16.2(d)	Balancing Data prices and other Standing Data prices used in Balancing	5.2.2
2.16.2(dA)	All Reserve Capacity Auction offers	5.1.2
2.16.2(e)	All bilateral quantities scheduled with the IMO	5.1.3
2.16.2(f)	All STEM Offers and STEM Bids, including both quantity and price terms	5.2.1.4
2.16.2(gA)	All Fuel Declarations	5.5.1
2.16.2(gB)	All Availability Declarations	5.5.2
2.16.2(gC)	All Ancillary Service Declarations	5.5.3
2.16.2(h)	Any substantial variations in STEM Offer and STEM Bid prices or quantities relative to recent past behaviour	5.5.4
2.16.2(hA)	Any evidence that a Market Customer has significantly over-stated its consumption as indicated by its Net Contract Position with a regularity that cannot be explained by a reasonable allowance for forecast uncertainty or the impact of Loss Factors	5.5.5
2.16.2(i)	The capacity available through Balancing from Generators and Non-Scheduled Generators and Dispatchable Loads	5.2.2.4
2.16.2(j)	The frequency and nature of Dispatch Instructions to Market Participants other than the Electricity Generation Corporation	5.2.2.5
2.16.2(k)	The number and frequency of outages of Scheduled Generators and Non-Scheduled Generators, and Market Participants' compliance with the outage scheduling process	5.5.6
2.16.2(l)	The performance of Market Participants with Reserve Capacity Obligations in meeting their obligations	5.1.6
2.16.2(m)	Details of Ancillary Service Contracts and Balancing Support Contracts that System Management enters into	5.6.2
2.16.2(o)	The number of Rule Change Proposals received, and details of Rule Change Proposals that the IMO has decided not to progress under clause 2.5.6	5.6.3
2.16.2(p)	Such other items of information as the IMO considers relevant to the functions of the IMO and the Economic Regulation Authority under this clause 2.16.	-
2.16.4(a)	Where applicable, calculation of the means and standard deviations of values in the Market Surveillance Data Catalogue	5.2.1 and 5.2.2
2.16.4(b)	Monthly, quarterly and annual moving averages of prices for the STEM Auctions and Balancing	5.2.1 and 5.2.2

Market Rule clause	Market Rule reporting requirement	See report section
2.16.4(c)	Statistical analysis of the volatility of prices in the STEM Auctions and Balancing	5.2.1 and 5.2.2
2.16.4(cA)	Any consistent or significant variations between the Fuel Declarations, Availability Declarations, and Ancillary Service Declarations for, and the actual operation of, a Market Participant facility in real-time	5.5.1
2.16.4(d)	The proportion of time the prices in the STEM Auctions and through Balancing are at each Energy Price Limit	5.2.1 and 5.2.2
2.16.4(e)	Correlation between capacity offered into the STEM Auctions and the incidence of high prices	5.2.1
2.16.4(f)	Correlation between capacity available in the Balancing and the incidence of high prices	5.2.2
2.16.4(g)	Exploration of the key determinants for high prices in the STEM and Balancing, including determining correlations or other statistical analysis between explanatory factors that the IMO considers relevant and price movements	5.2.1.3
2.16.4(h)	Such other analysis as the IMO considers appropriate or is requested of the IMO by the Economic Regulation Authority	-

Appendix 2 Submissions received

Alinta Sales Pty Ltd

Energy Supply Association of Australia

Landfill Gas and Power

Sustainable Energy Association of Australia

Synergy

System Management

Western Power

Appendix 3 Market Surveillance Data Catalogue – additional information

Short Term Energy Market

Short Term Energy Market Offers and Bids

Short Term Energy Market Offers

Figure 29 to Figure 42 show STEM Offers for each Market Participant from market commencement to 31 July 2011. In the current Reporting Period, three Market Participants have commenced making offers in the STEM, namely Landfill Gas and Power, Tiwest and Western Energy.

Figure 29 shows Alcoa's offers were exclusively priced at the Alternative Maximum STEM Price in the first half of the current Reporting Period and at the Maximum STEM Price for the remainder of the period.

Figure 29 Alcoa's daily average STEM Offers (cumulative MWh per Trading Interval)

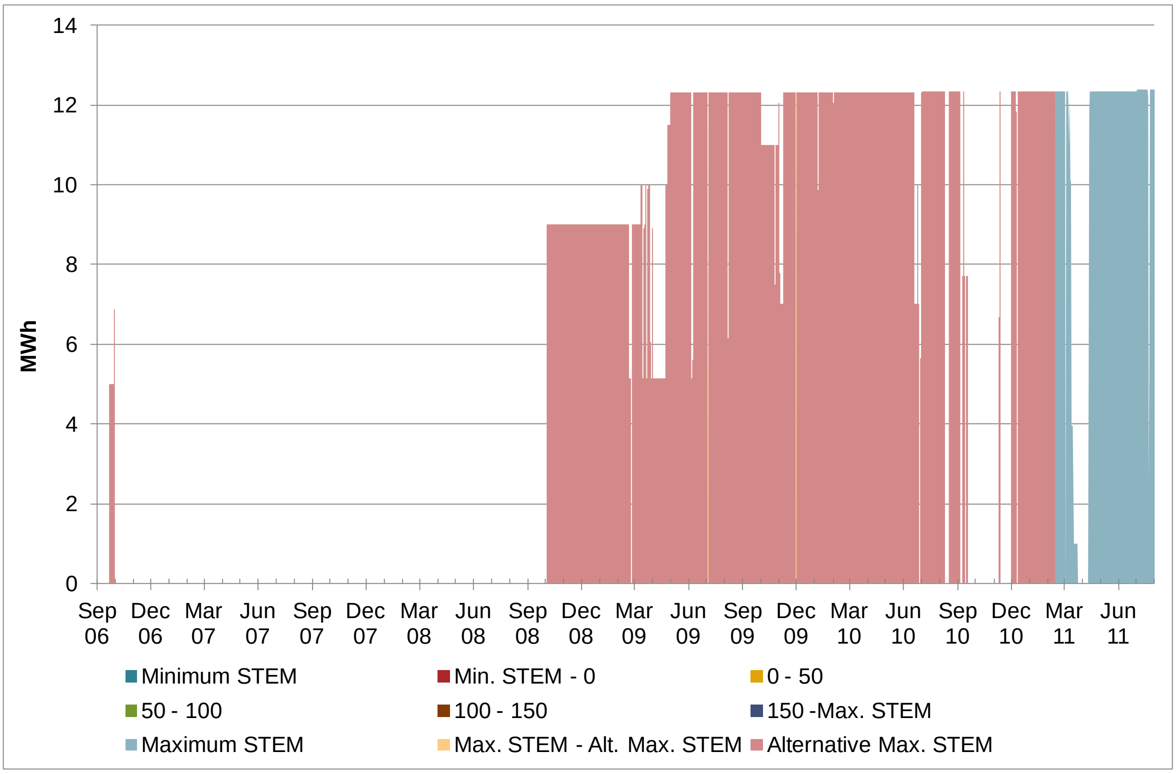


Figure 30 shows that Alinta continued to offer significant volumes into the STEM, priced at the Alternative Maximum STEAM Price, and also offered increased volumes priced at the Maximum STEM Price.

Figure 30 Alinta's daily average STEM Offers (cumulative MWh per Trading Interval)

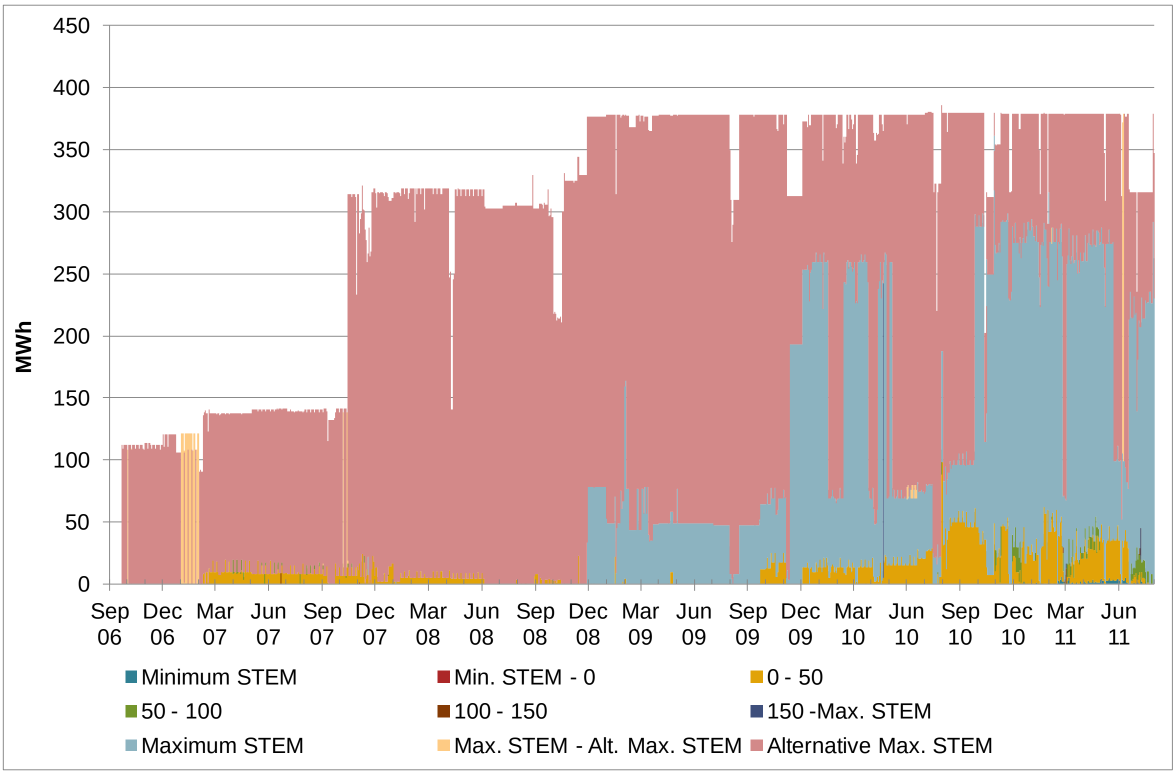


Figure 31 shows Goldfields Power offered volumes priced almost exclusively at the Alternative Maximum STEM Price during the current Reporting Period.

Figure 31 **Goldfields Power's daily average STEM Offers (cumulative MWh per Trading Interval)**

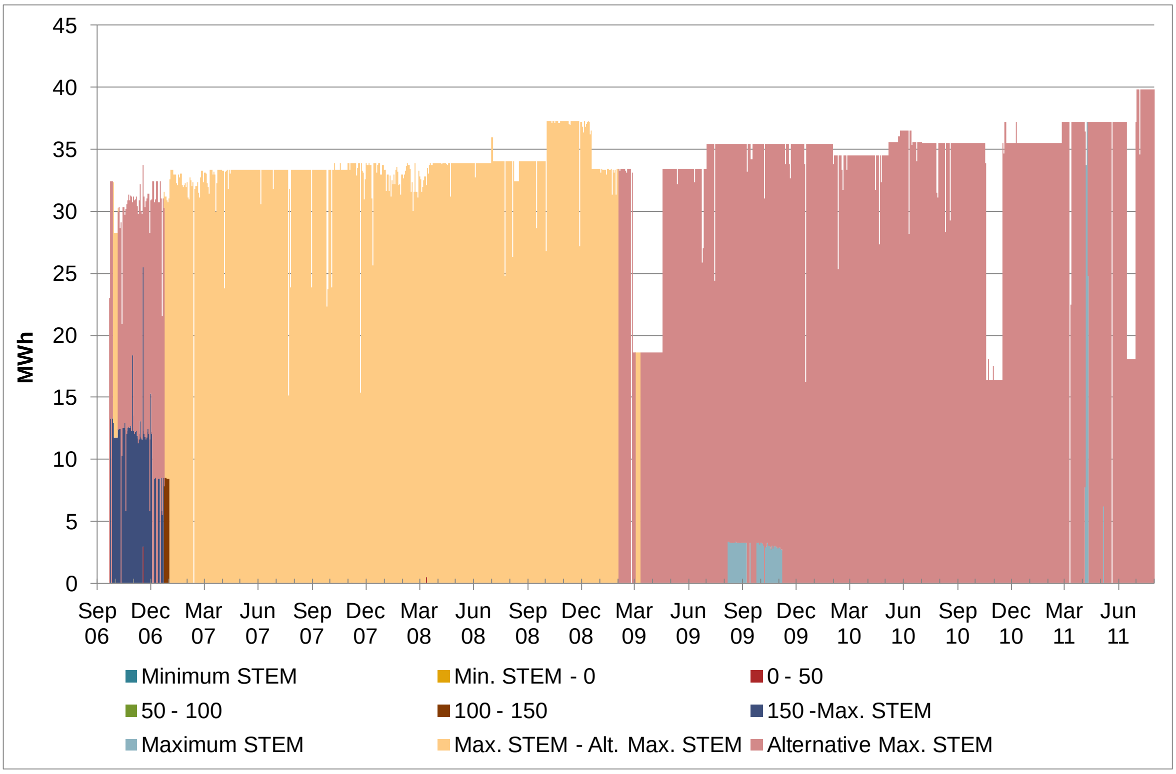


Figure 32, Figure 33 and Figure 35 show, respectively, that during the current Reporting Period, Griffin Power, Griffin Power 2 and NewGen Kwinana have at times offered significant volumes into the STEM, in a range of price bands.

Figure 32 **Griffin Power's daily average STEM Offers (cumulative MWh per Trading Interval)**

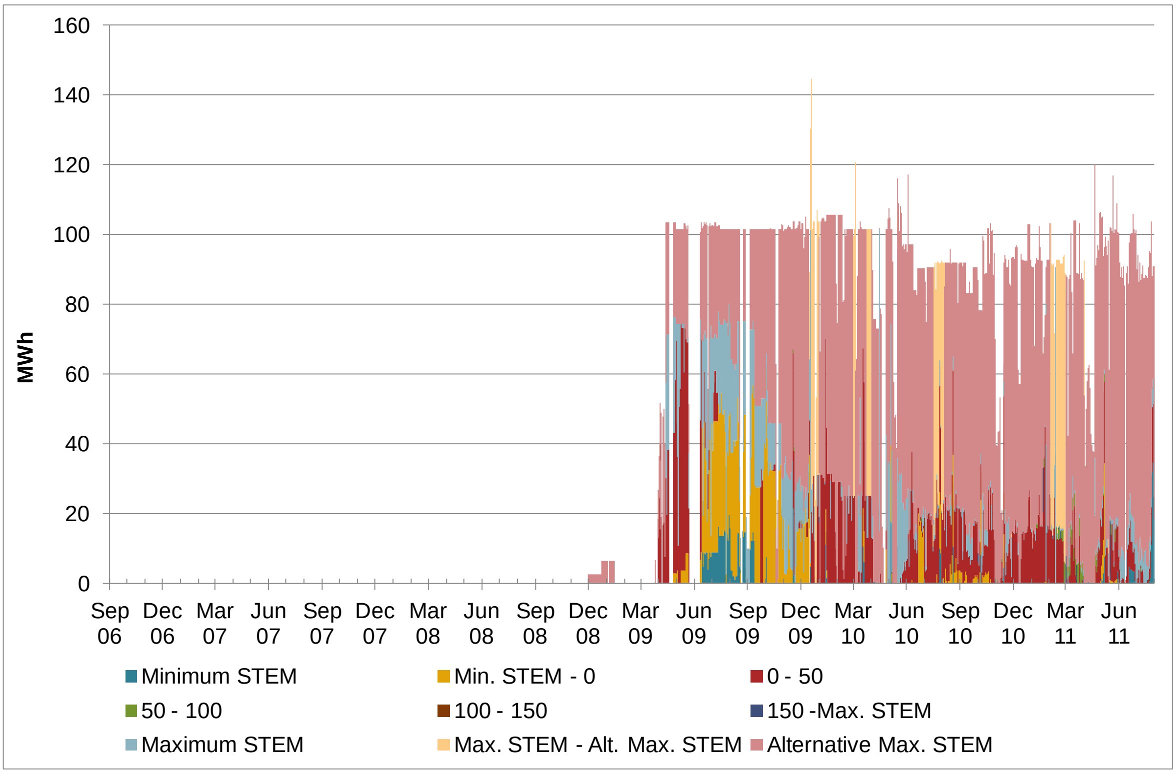


Figure 33 **Griffin Power 2's daily average STEM Offers (cumulative MWh per Trading Interval)**

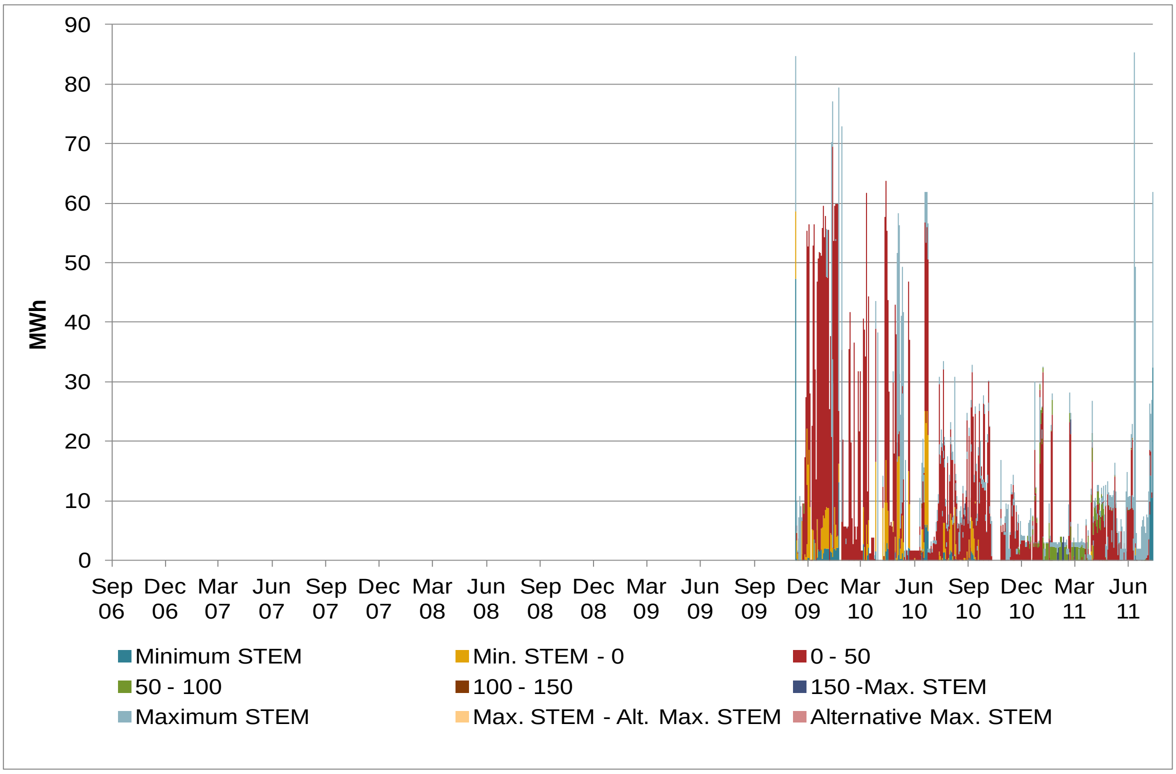


Figure 34 shows Landfill Gas and Power has offered large volumes at prices between $150/MWh and the Maximum STEM Price since it commenced making offers in the STEM from February 2011.

Figure 34 Landfill Gas and Power's daily average STEM Offers (cumulative MWh per Trading Interval)

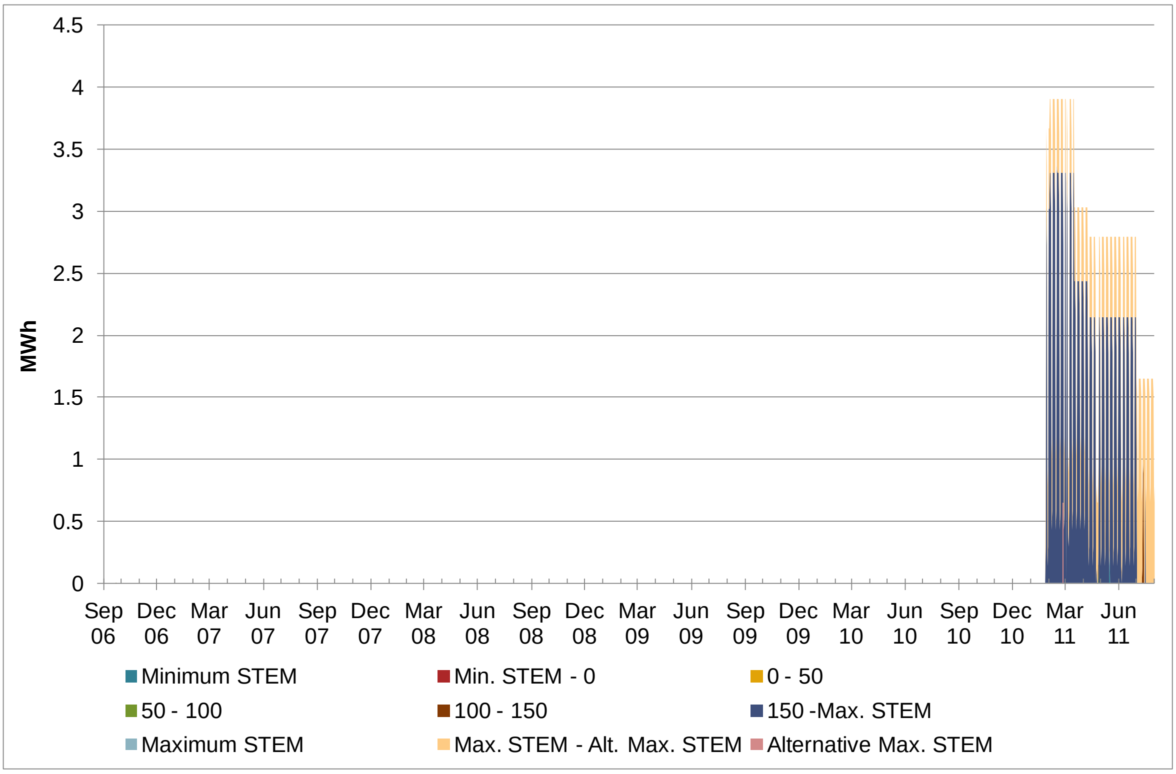


Figure 35 NewGen Power Kwinana's daily average STEM Offers (cumulative MWh per Trading Interval)

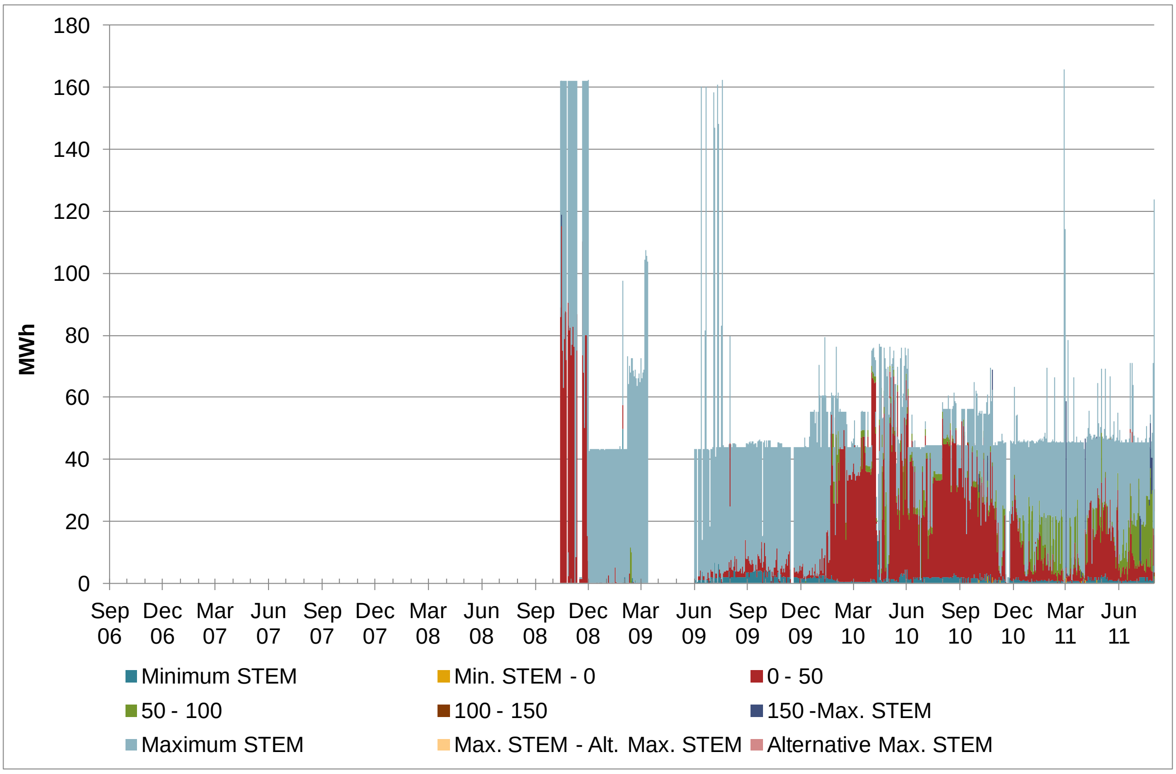


Figure 36 shows that NewGen Neerabup's STEM Offers continue to be almost exclusively priced at the Maximum STEM Price during the current Reporting Period.

Figure 36 NewGen Neerabup's daily average STEM Offers (cumulative MWh per Trading Interval)

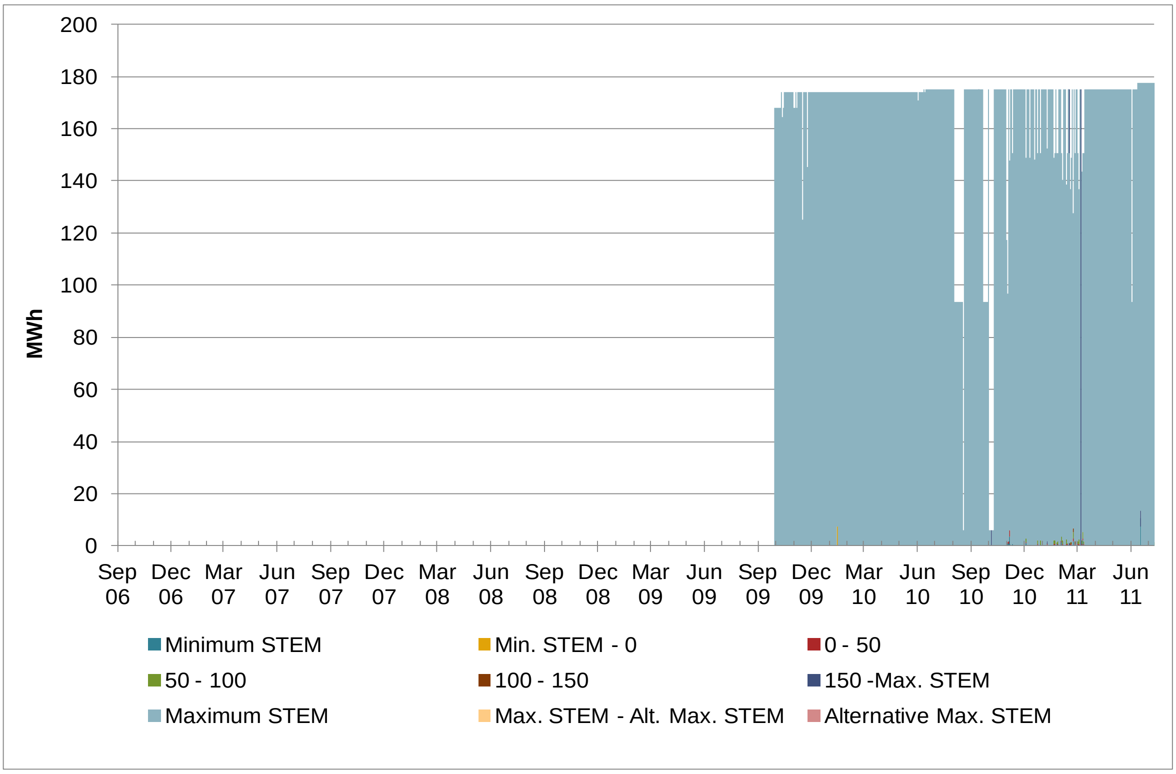


Figure 37 and Figure 38, respectively, shows that Perth Energy and Southern Cross Energy have primarily priced their STEM Offers at the Alternative Maximum STEM Price during the current Reporting Period.

Figure 37 Perth Energy's daily average STEM Offers (cumulative MWh per Trading Interval)

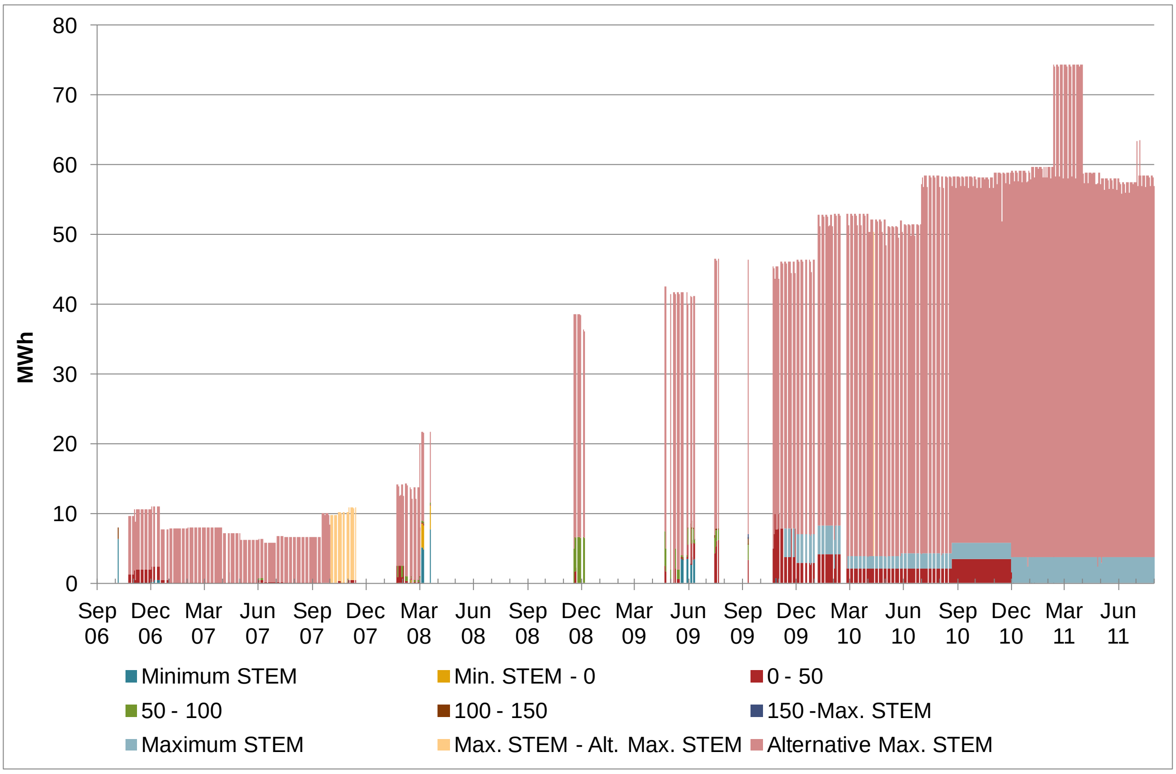


Figure 38 Southern Cross Energy's daily average STEM Offers (cumulative MWh per Trading Interval)

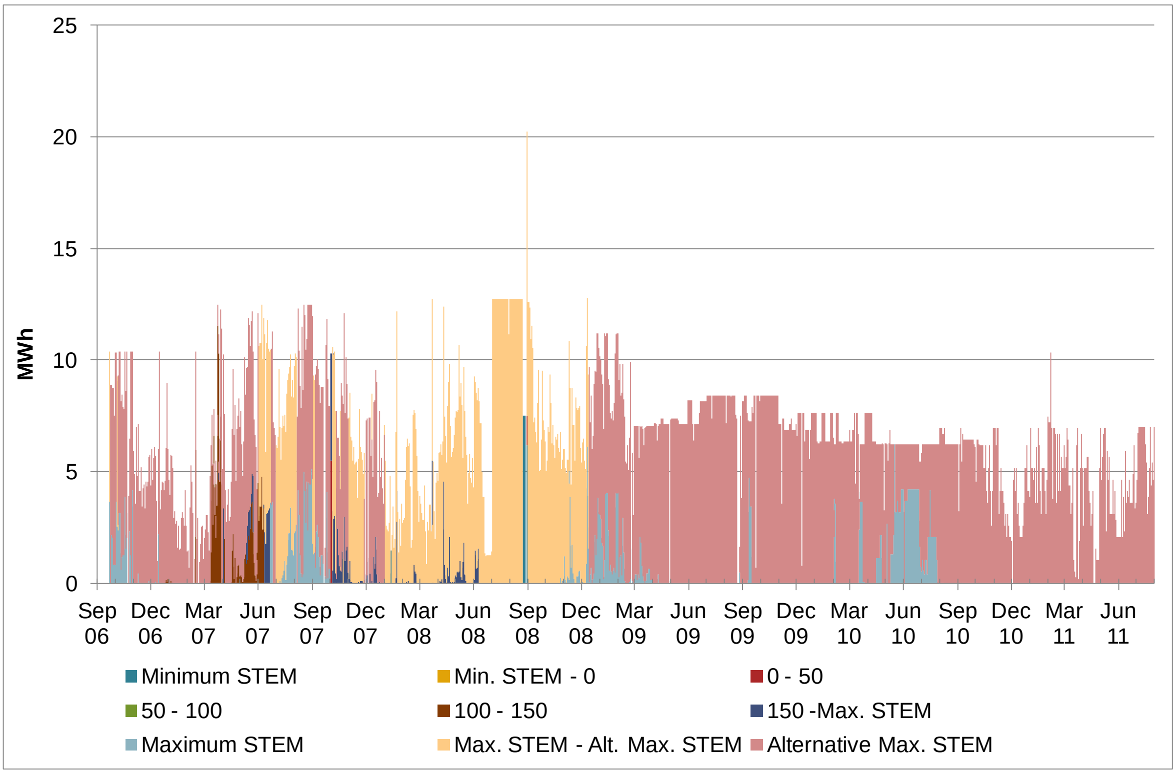


Figure 39 shows that Tiwest has started to offer energy exclusively at the Alternative Maximum STEM Price since March 2011.

Figure 39 Tiwest's daily average STEM Offers (cumulative MWh per Trading Interval)

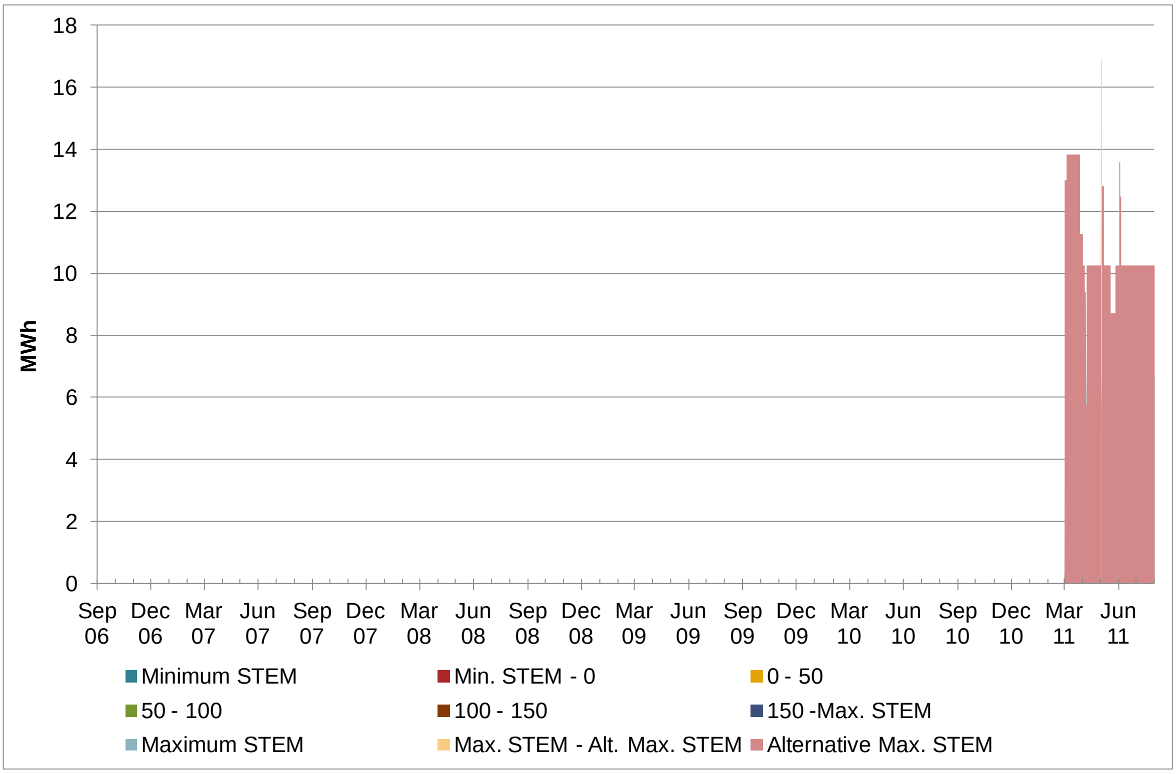


Figure 40 shows that, since September 2010, Western Energy has made offers at the Alternative Maximum STEM Price and also at prices between $150/MWh to the Maximum STEM Price.

Figure 40 Western Energy's daily average STEM Offers (cumulative MWh per Trading Interval)

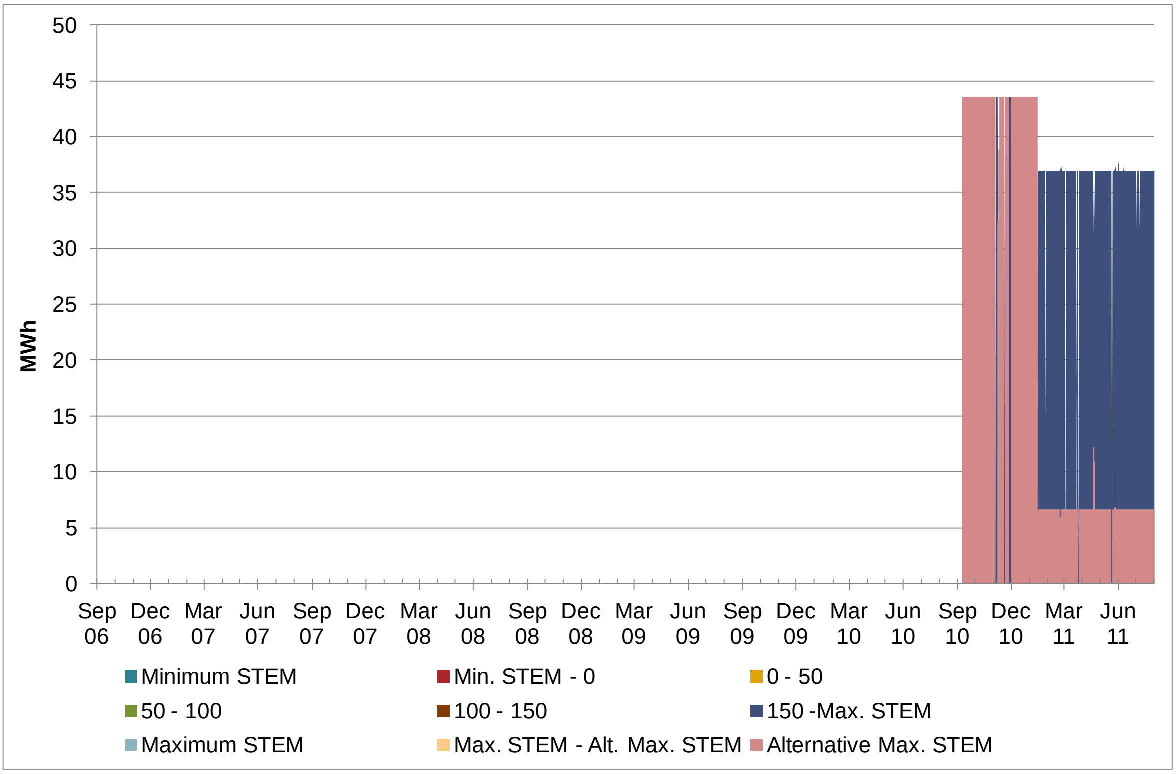


Figure 41 shows Synergy has continued to offer significant volumes into the STEM in the current Reporting Period, primarily priced at the Alternative Maximum STEM Price.

Figure 41 Synergy's daily average STEM Offers (cumulative MWh per Trading Interval)

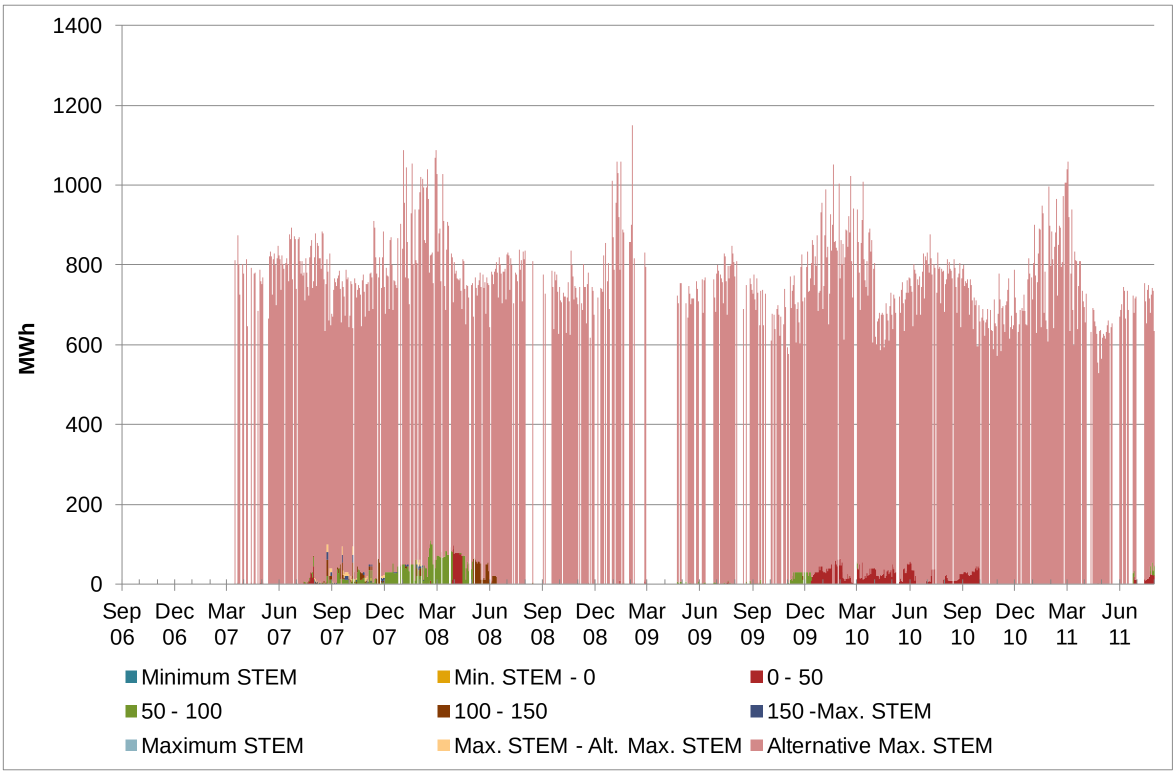
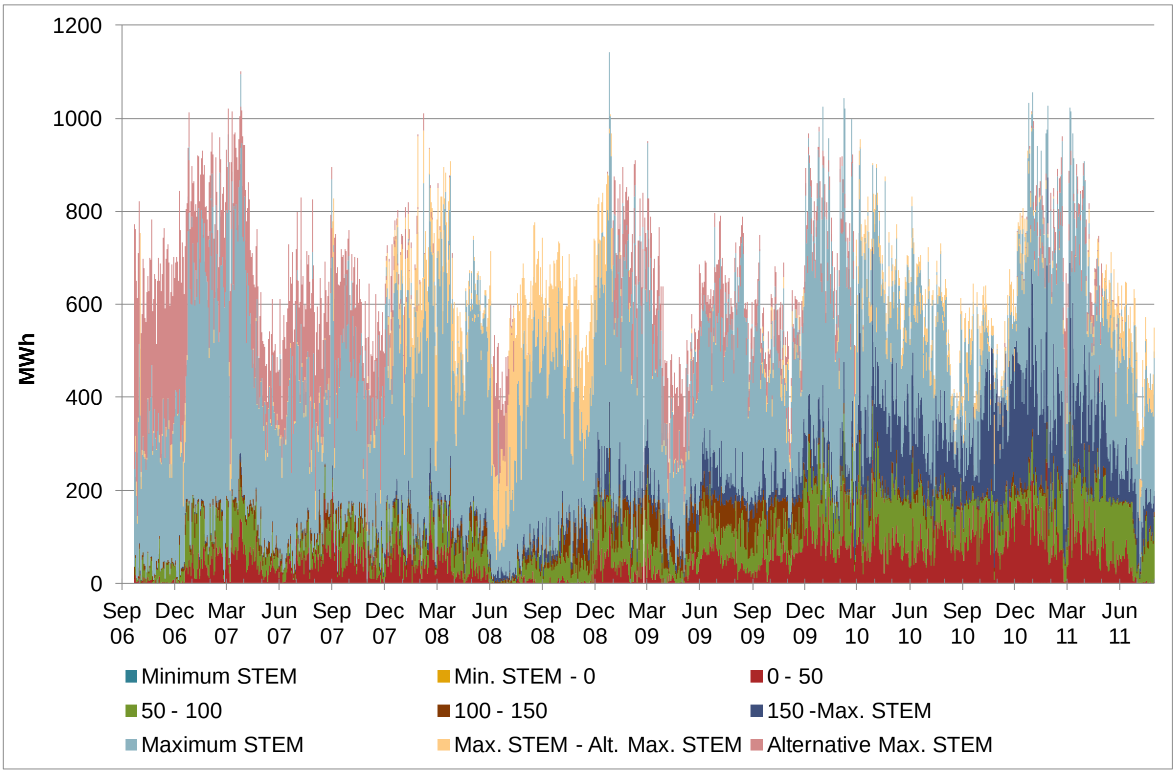


Figure 42 shows Verve Energy has consistently offered significant volumes into the STEM since market commencement, with the majority of Verve Energy's offers priced at the Maximum STEM Price. Since March 2011, there has been a significant drop in the overall STEM Offer quantities from Verve Energy. Verve Energy has tended to offer larger volumes at prices between $50/MWh and $100/MWh and at the Maximum STEM Price, with these offers accounting for major proportion of Verve Energy's total offers. During this period the volumes offered at cheaper prices between $0/MWh and $50/MWh, and between $150/MWh and Maximum STEM Price reduced significantly.

Figure 42 Verve Energy's daily average STEM Offers (cumulative MWh per Trading Interval)



Short Term Energy Market Bids

Figure 43 to Figure 57 show STEM Bids for each Market Participant from market commencement to 31 July 2011. In the current Reporting Period, four Market Participants have commenced making bids in the STEM, namely ERM Power Retail, Landfill Gas and Power, Tiwest and Western Energy. As can be seen in the figures below, these participants have bid relatively low volumes into the STEM in a range of price bands.

Figure 43 Alcoa's daily average STEM Bids (cumulative MWh per Trading Interval)

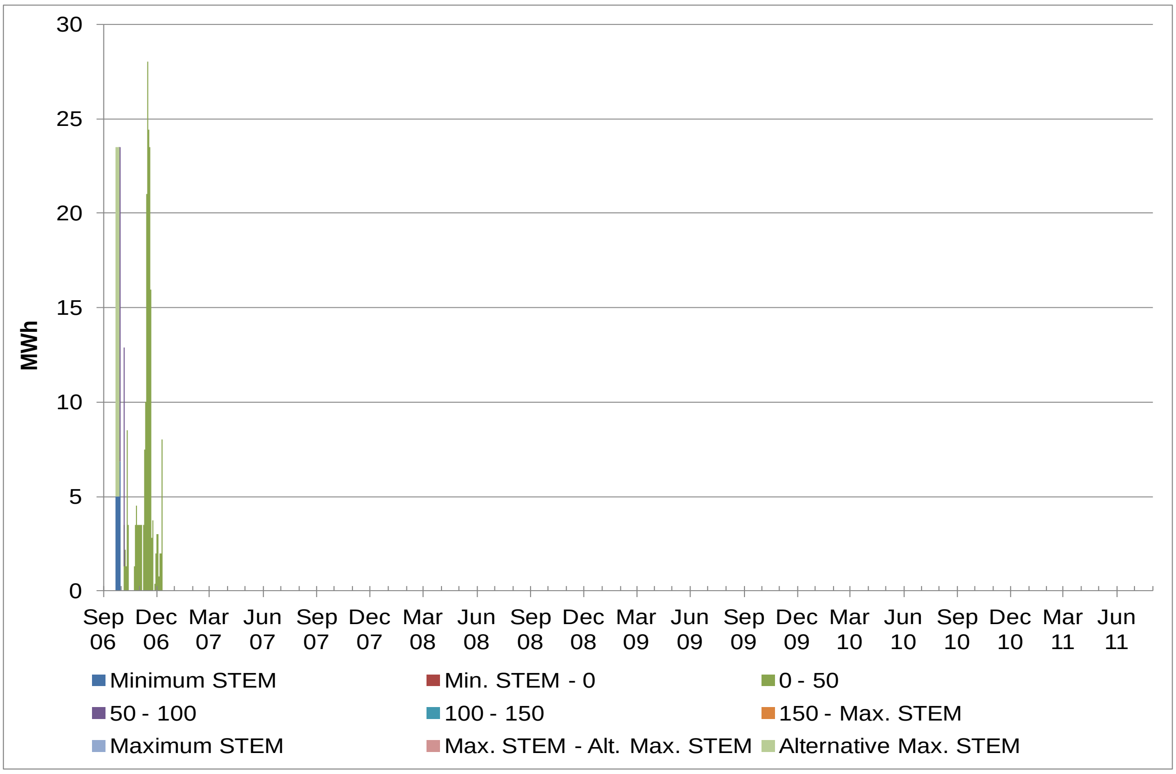


Figure 44 shows Alinta has consistently bid significant volumes in the STEM, at the Minimum STEM Price, and it also bid an increasing amount of volumes priced between \$0/MWh and \$50/MWh, compared with the previous reporting period. This situates Alinta's overall bid at low or negative prices.

Figure 44 Alinta's daily average STEM Bids (cumulative MWh per Trading Interval)

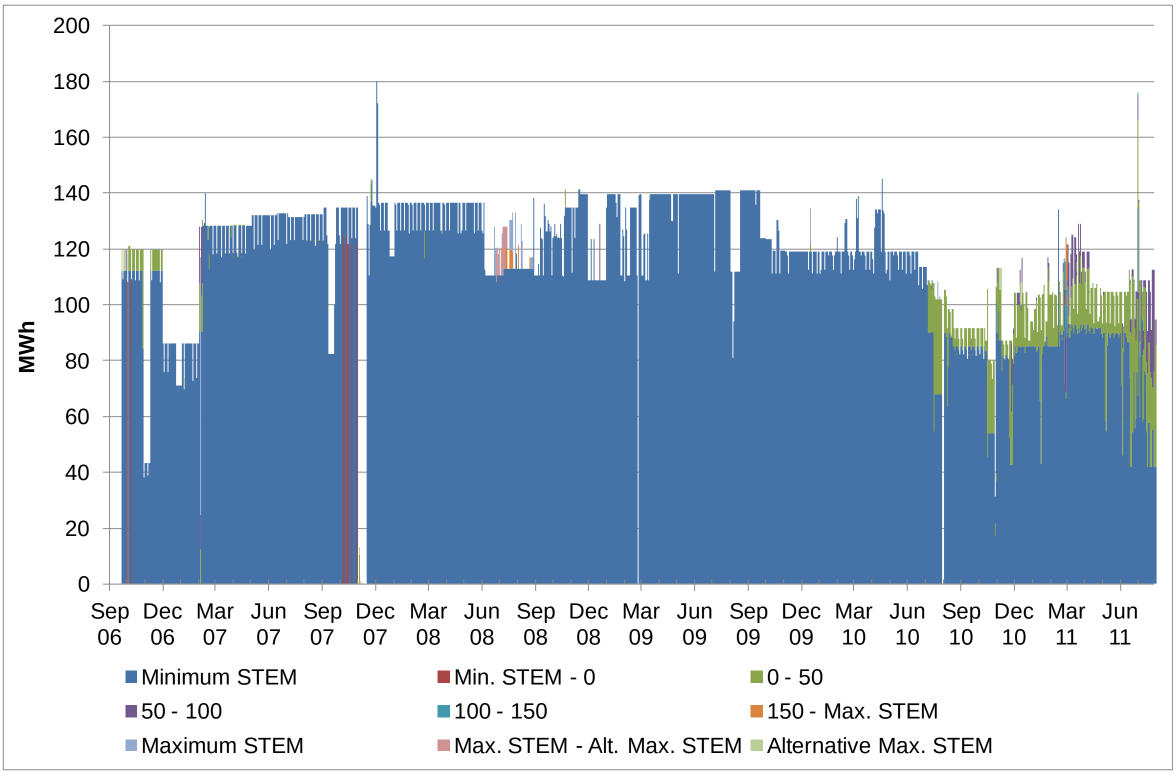


Figure 45 ERM Power's daily average STEM Bids (cumulative MWh per Trading Interval)

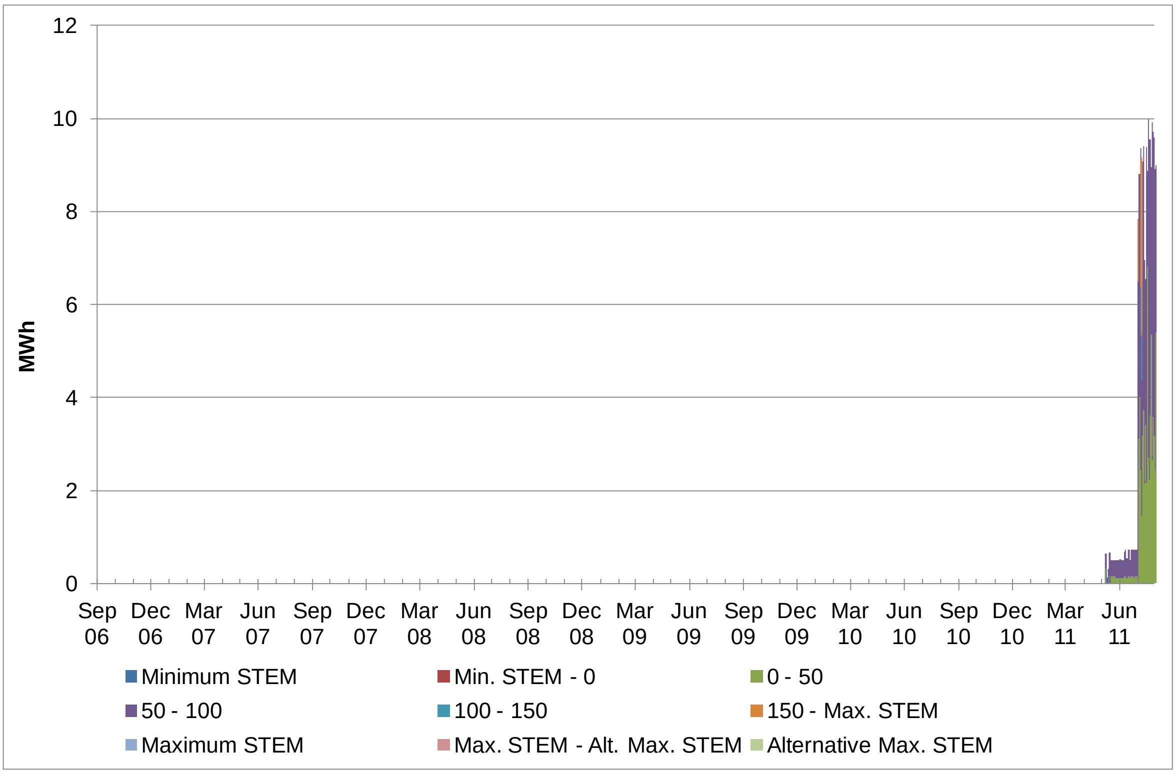


Figure 46 Goldfields Power's daily average STEM Bids (cumulative MWh per Trading Interval)

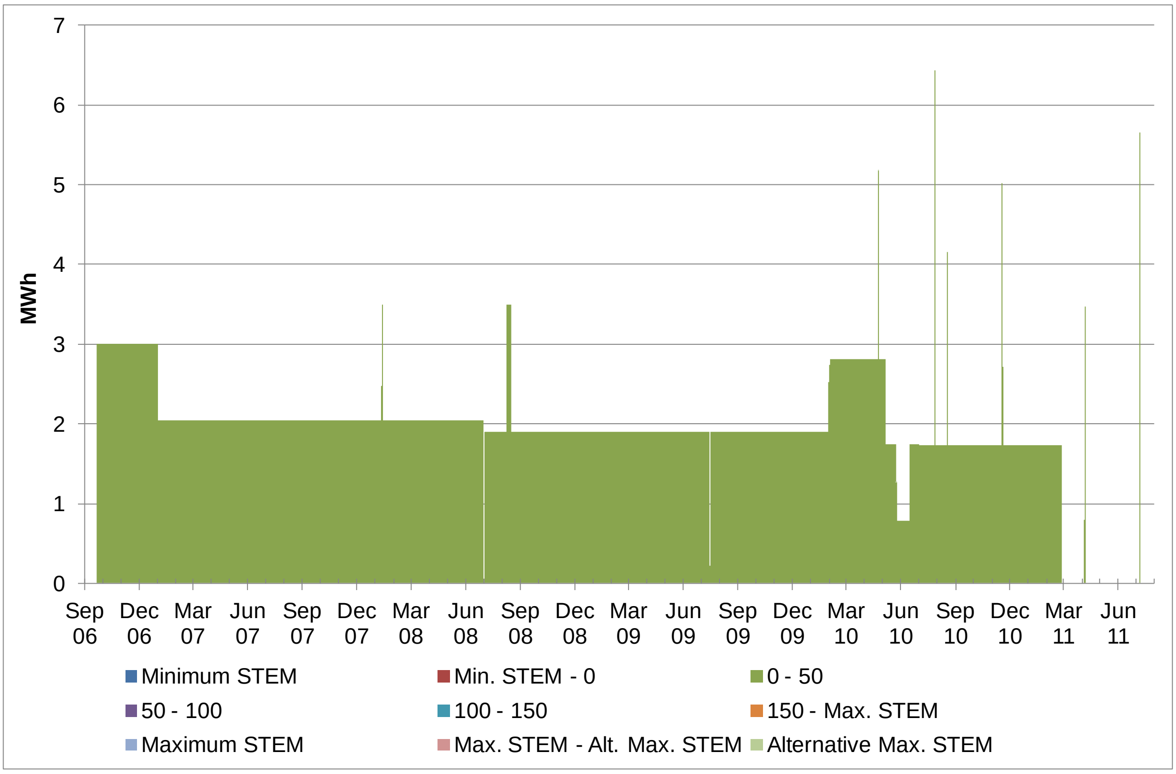


Figure 47 Griffin Energy's daily average STEM Bids (cumulative MWh per Trading Interval)

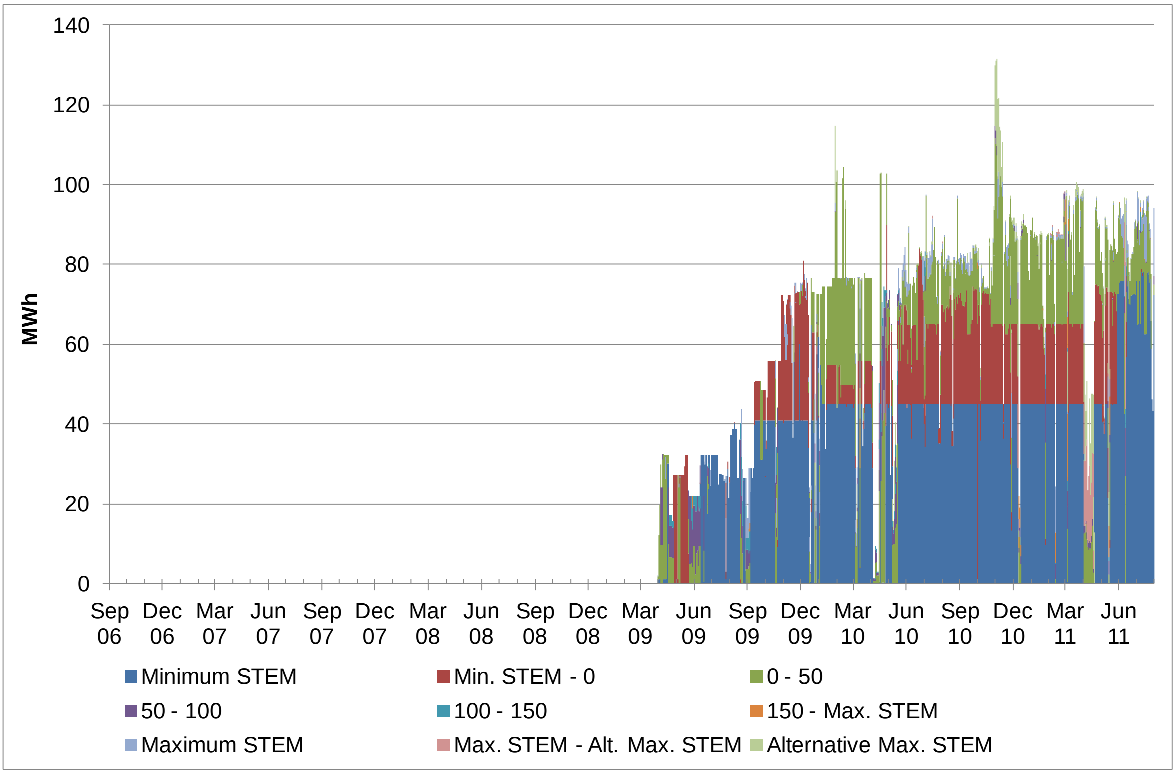


Figure 48 Griffin Energy 2's daily average STEM Bids (cumulative MWh per Trading Interval)

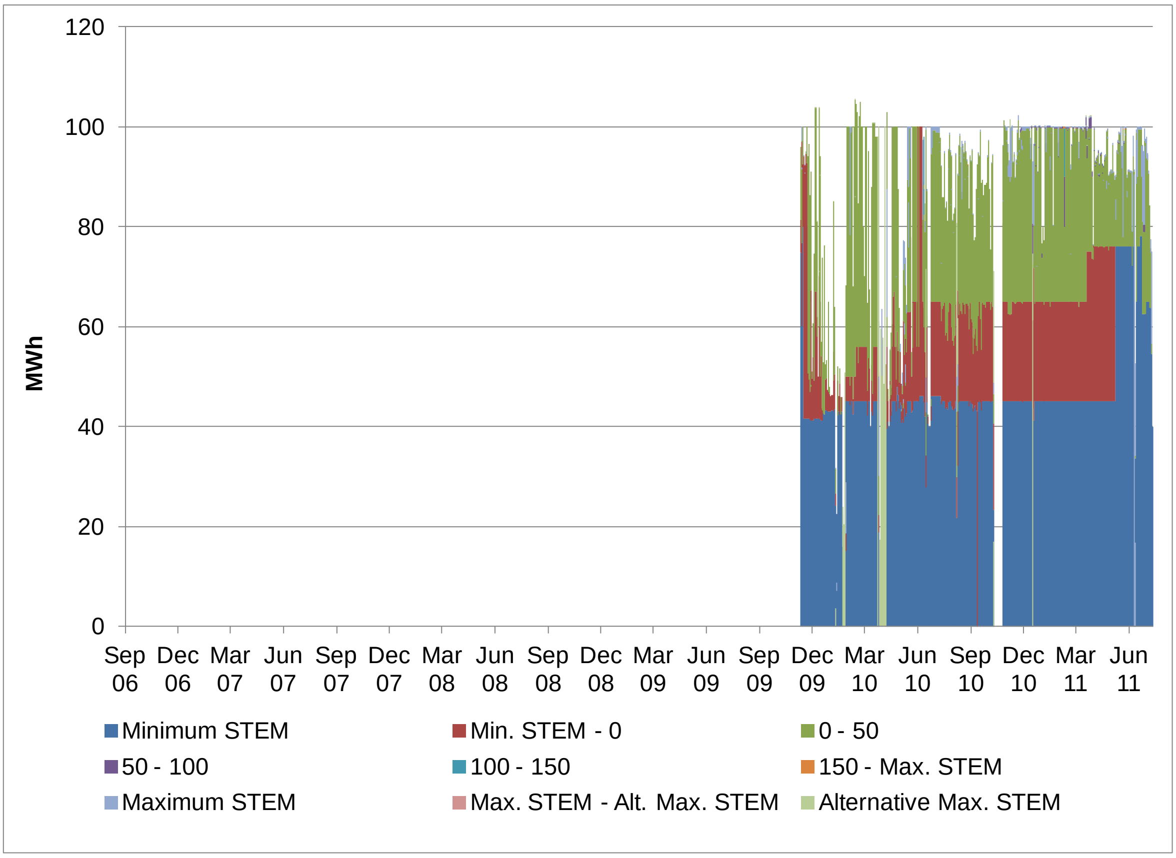


Figure 49 Landfill Gas and Power's daily average STEM Bids (cumulative MWh per Trading Interval)

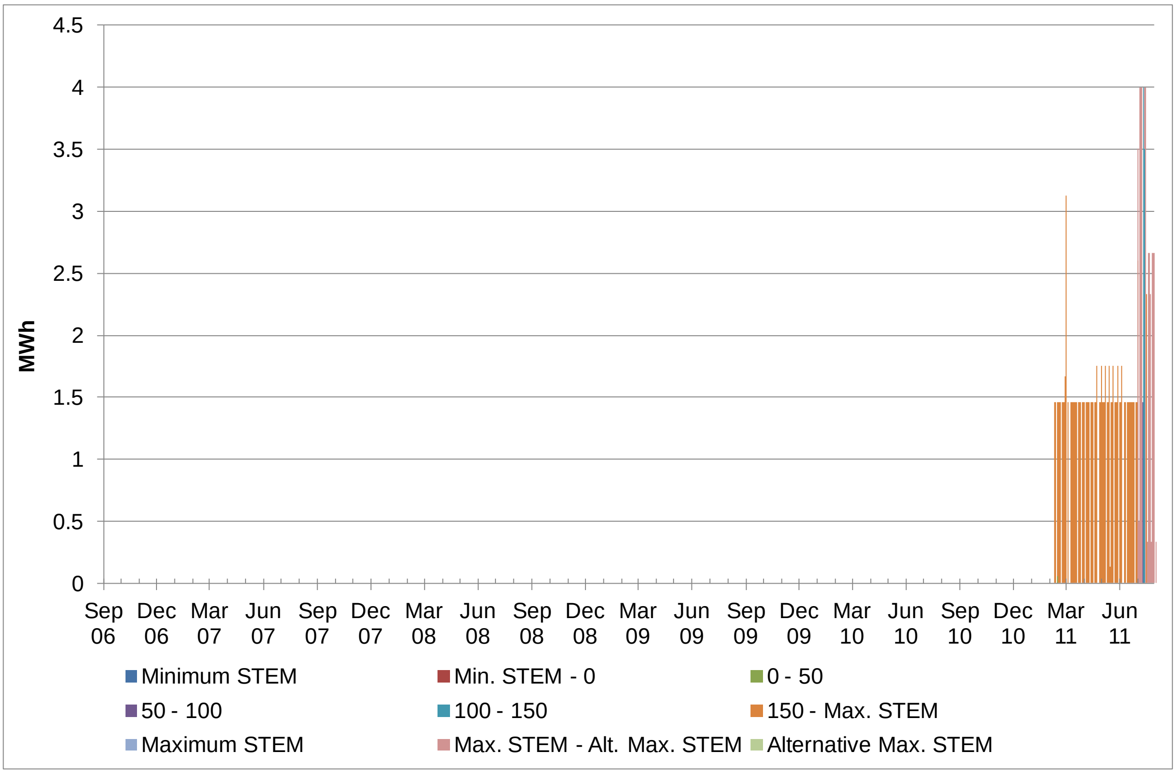


Figure 50 NewGen Power Kwinana's daily average STEM Bids (cumulative MWh per Trading Interval)

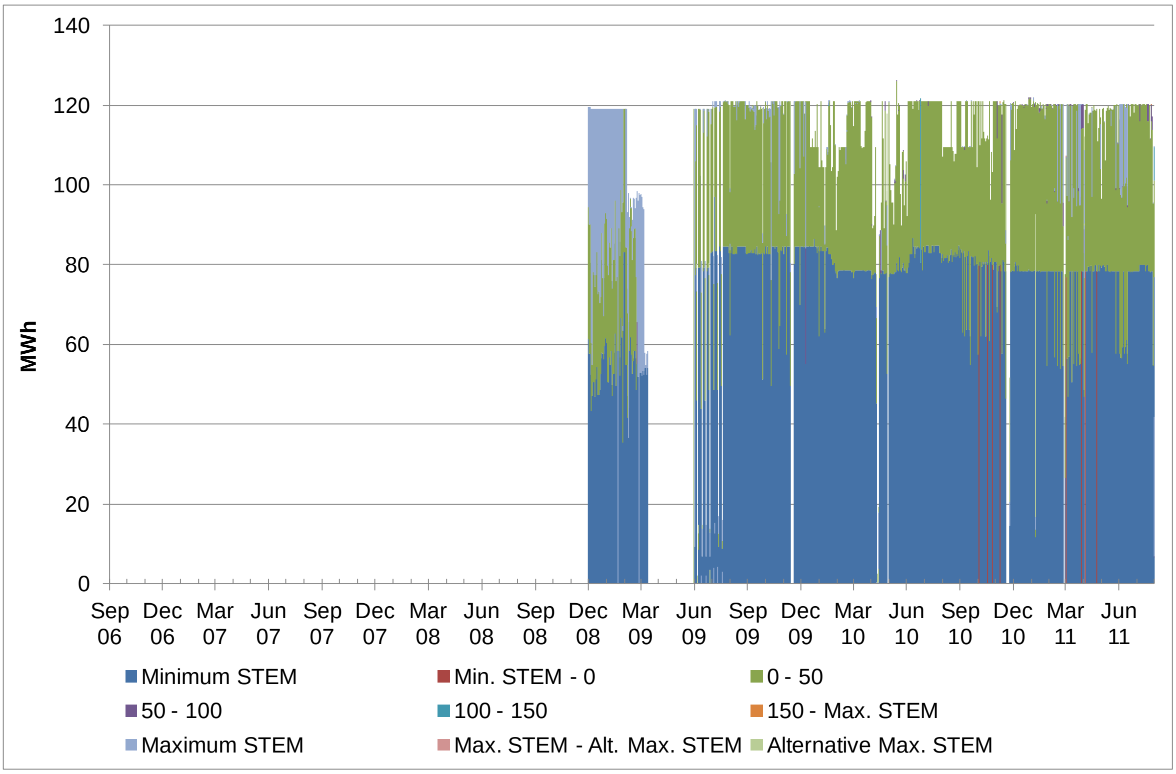


Figure 51 NewGen Neerabup's daily average STEM Bids (cumulative MWh per Trading Interval)

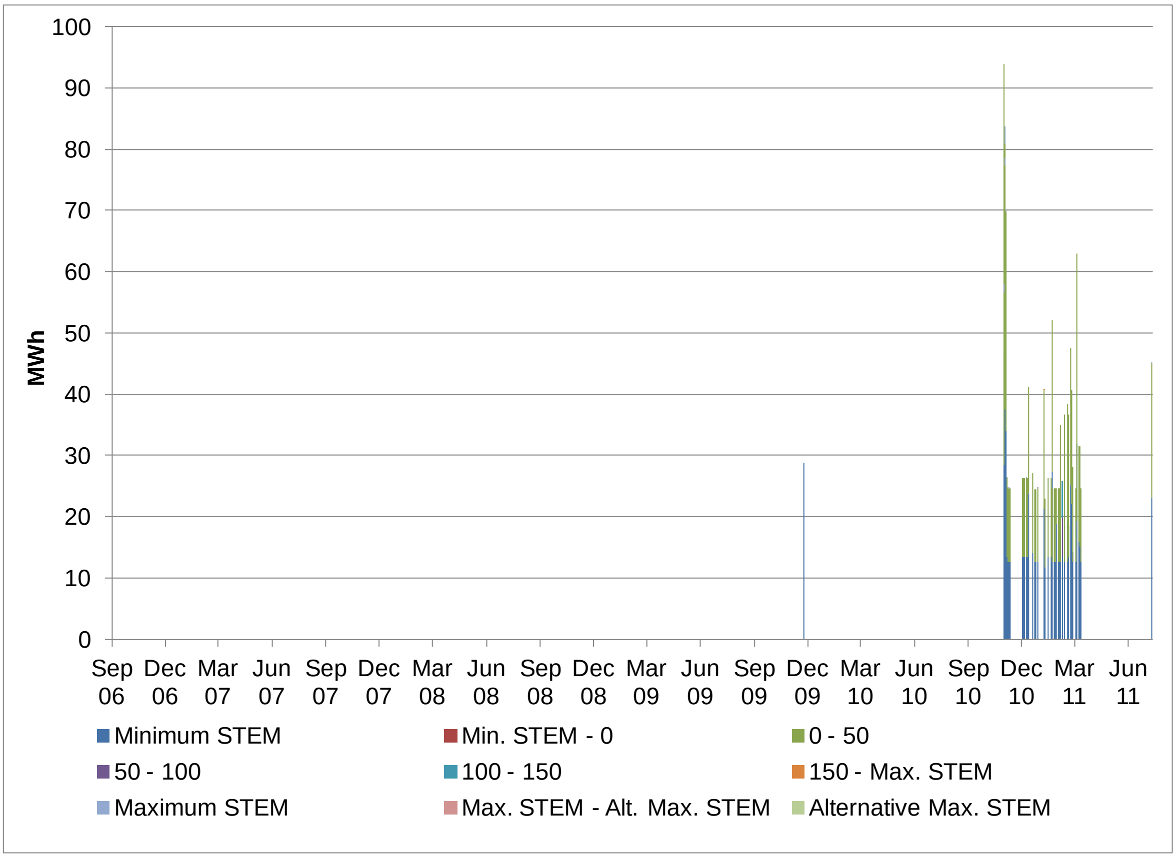


Figure 52 Perth Energy's daily average STEM Bids (cumulative MWh per Trading Interval)

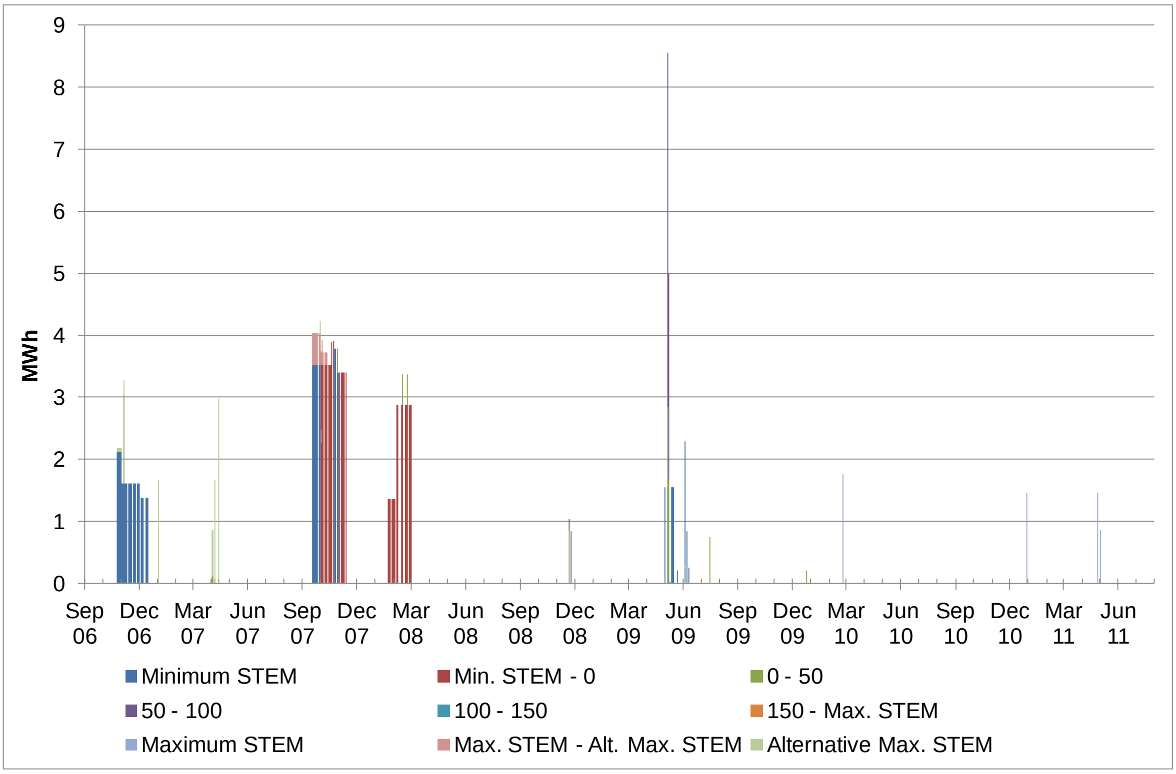


Figure 53 Southern Cross Energy's daily average STEM Bids (cumulative MWh per Trading Interval)

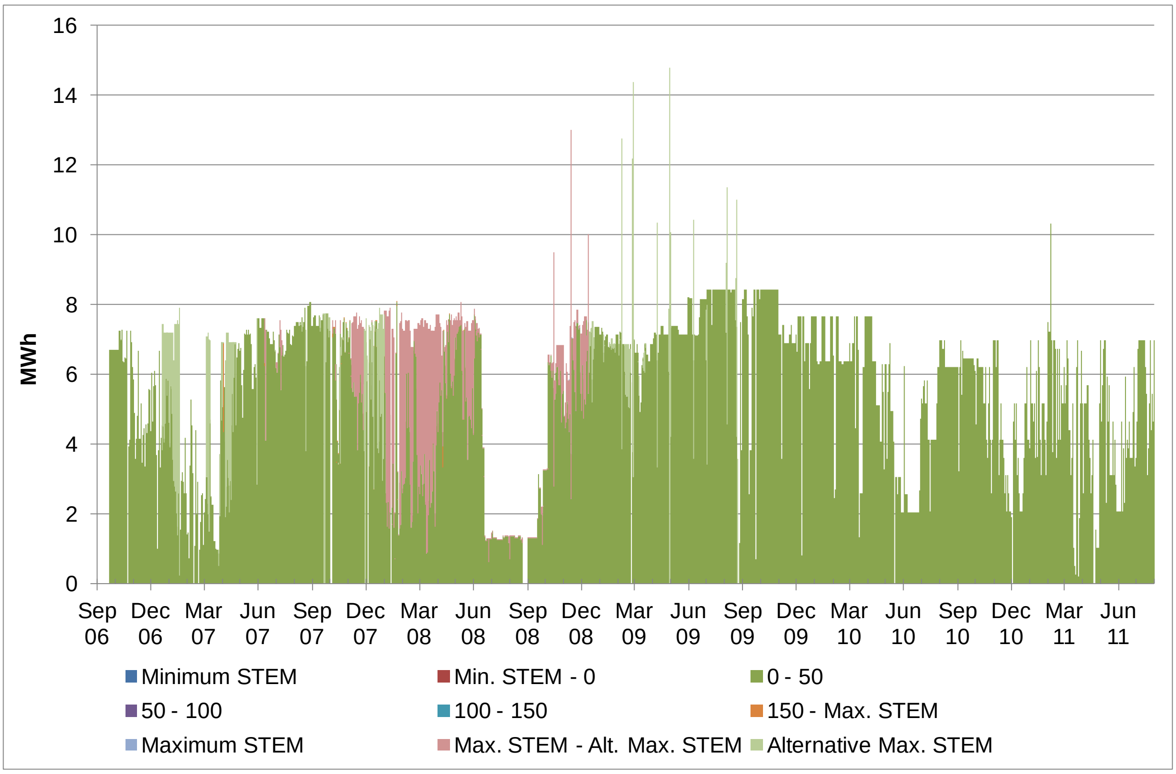


Figure 54 Tiwest's daily average STEM Bids (cumulative MWh per Trading Interval)

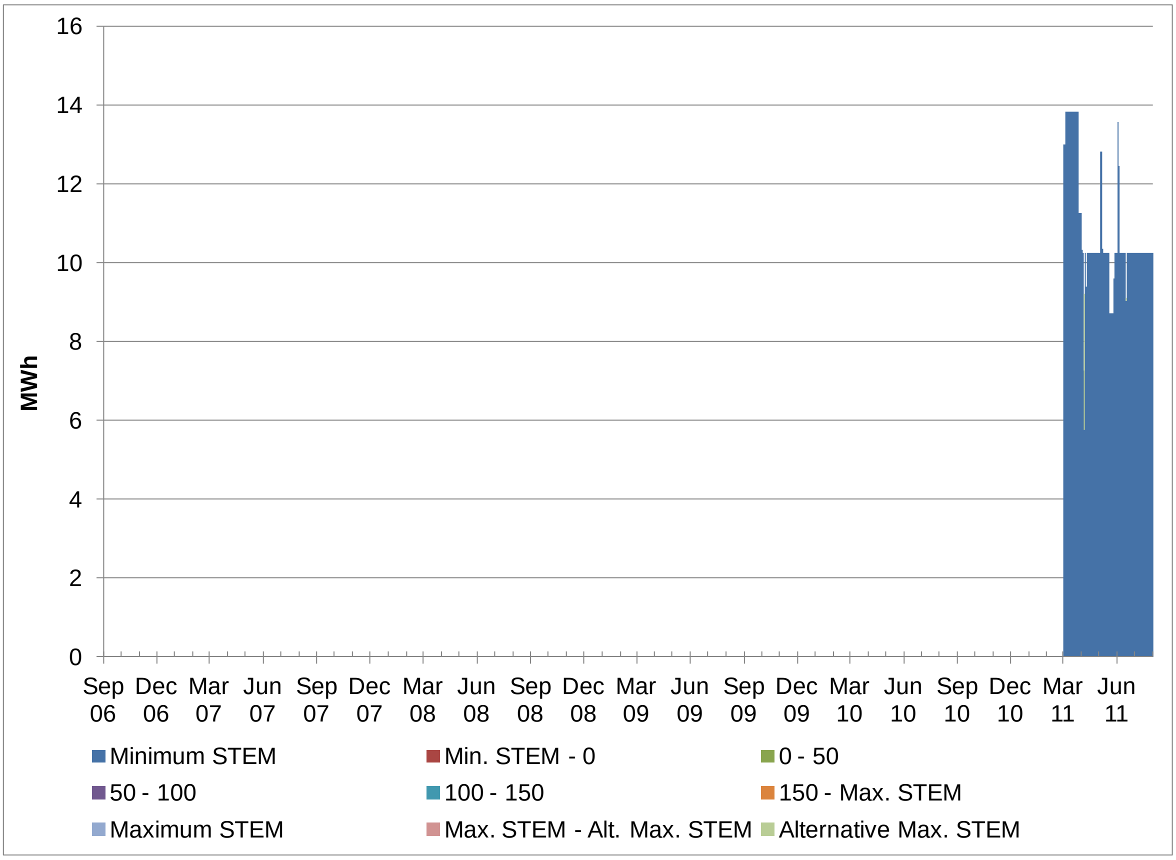


Figure 55 **Western Energy's daily average STEM Bids (cumulative MWh per Trading Interval)**

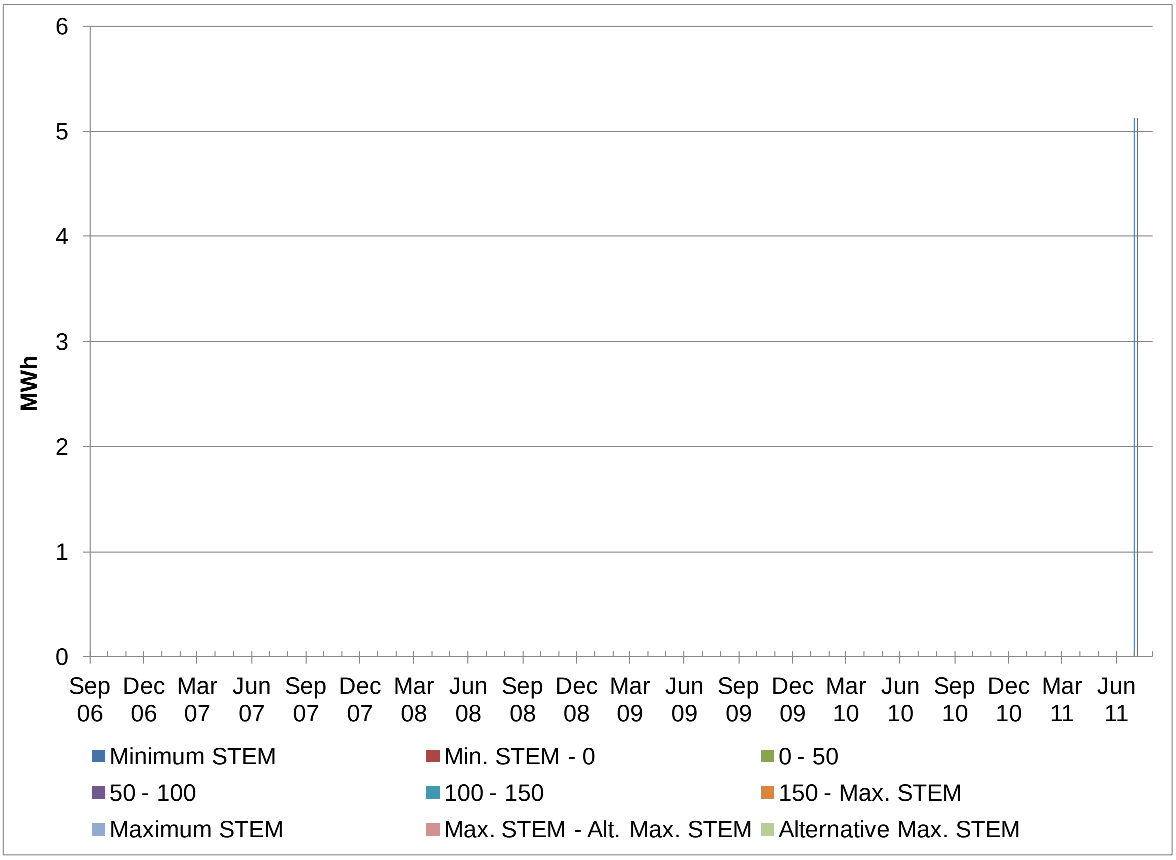


Figure 56 **Synergy's daily average STEM Bids (cumulative MWh per Trading Interval)**

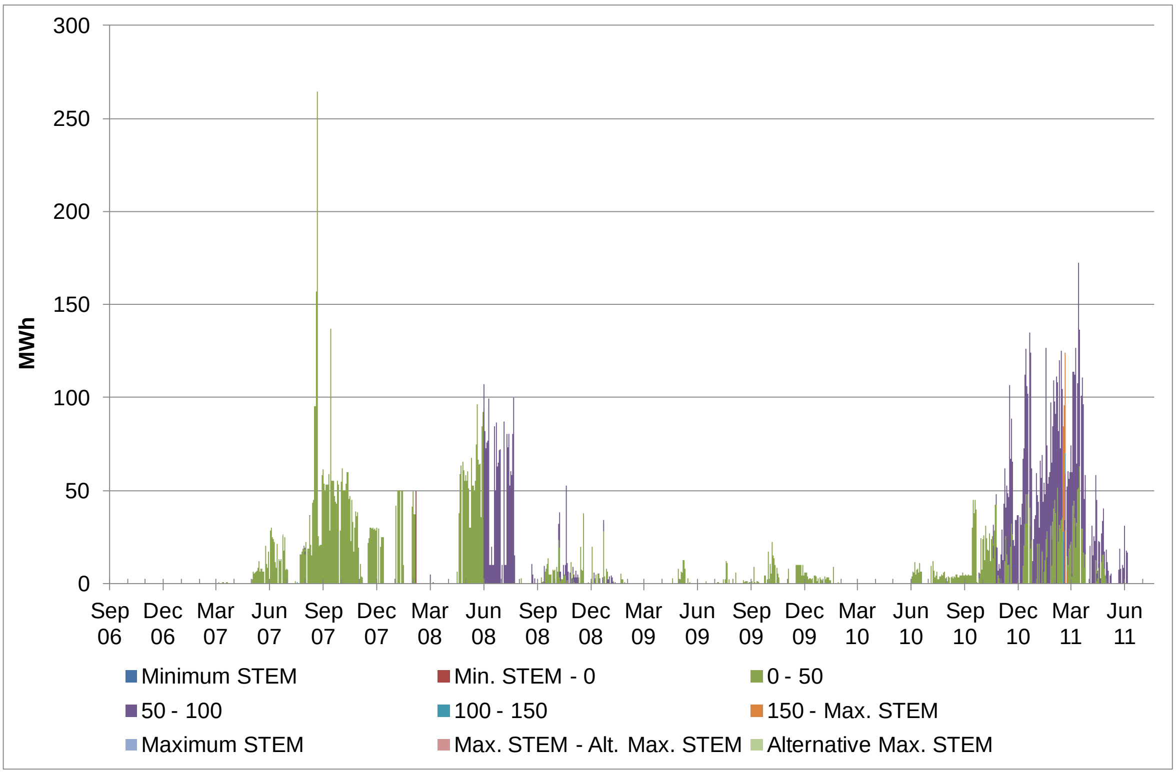
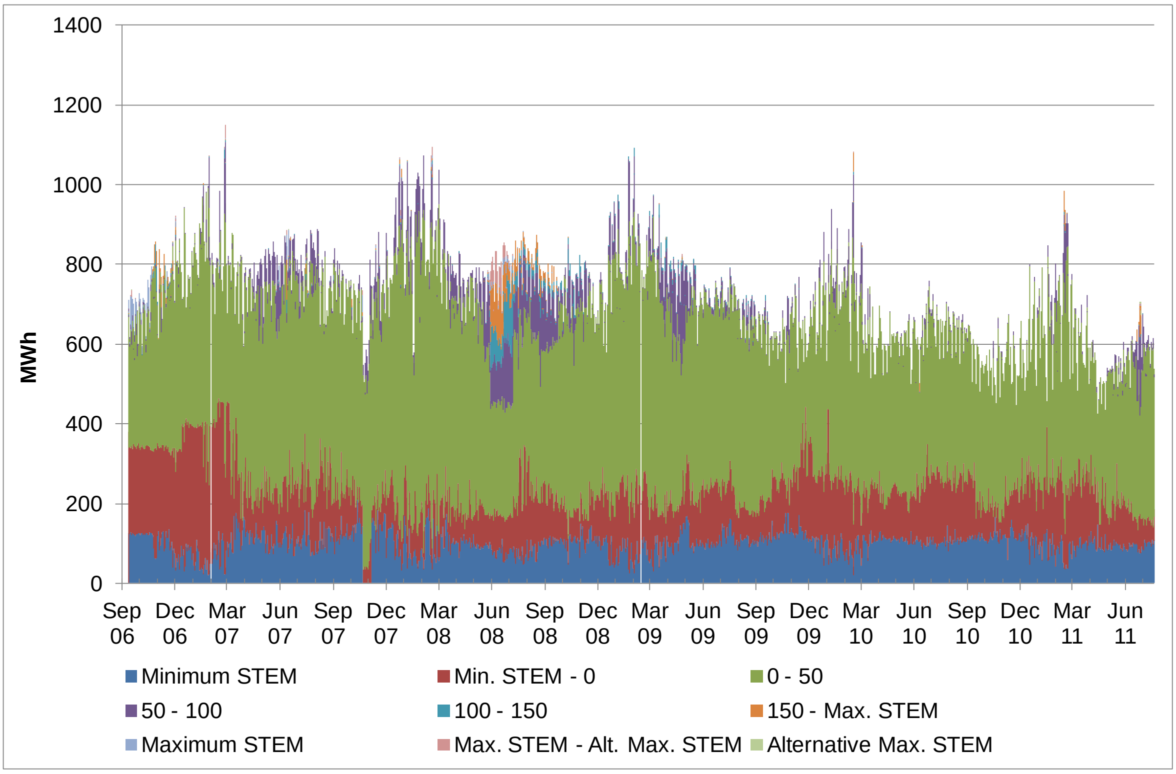


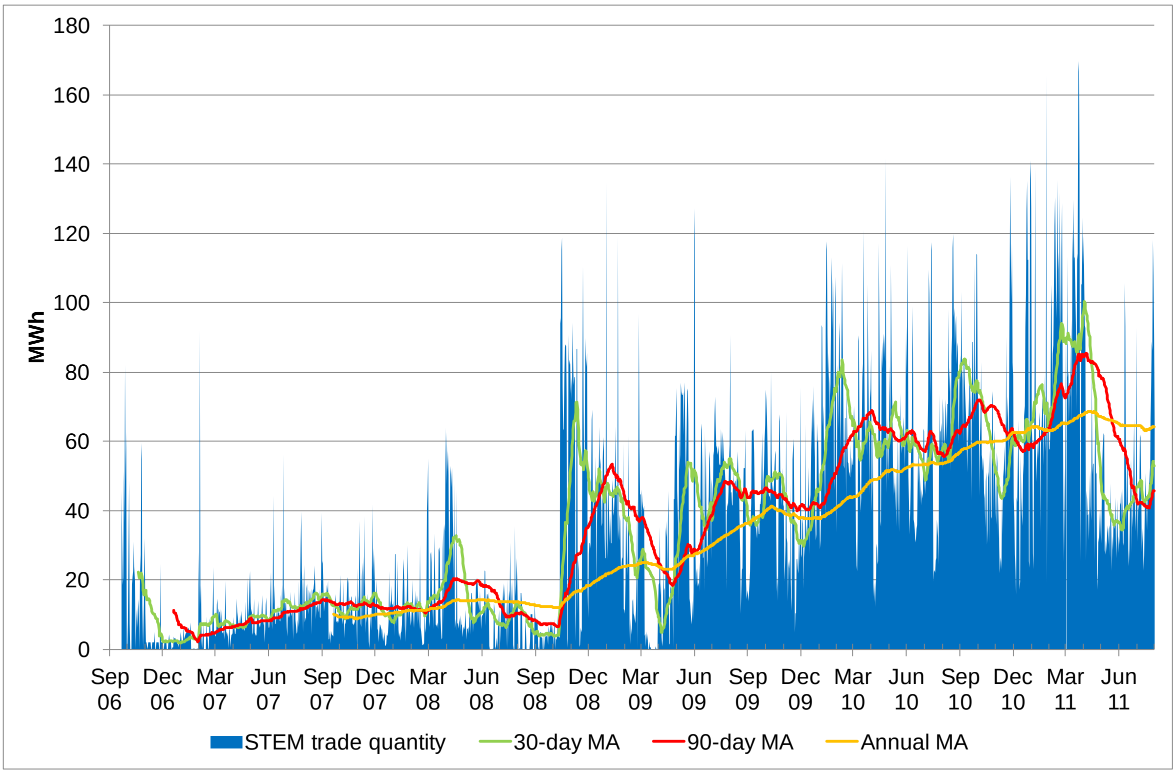
Figure 57 shows Verve Energy has consistently bid significant volumes in the STEM since market commencement, principally at low or negative prices.

Figure 57 Verve Energy's daily average STEM Bids (cumulative MWh per Trading Interval)



Short Term Energy Market traded volumes

Figure 58 Average STEM Clearing Quantities (per Trading Day)



Balancing

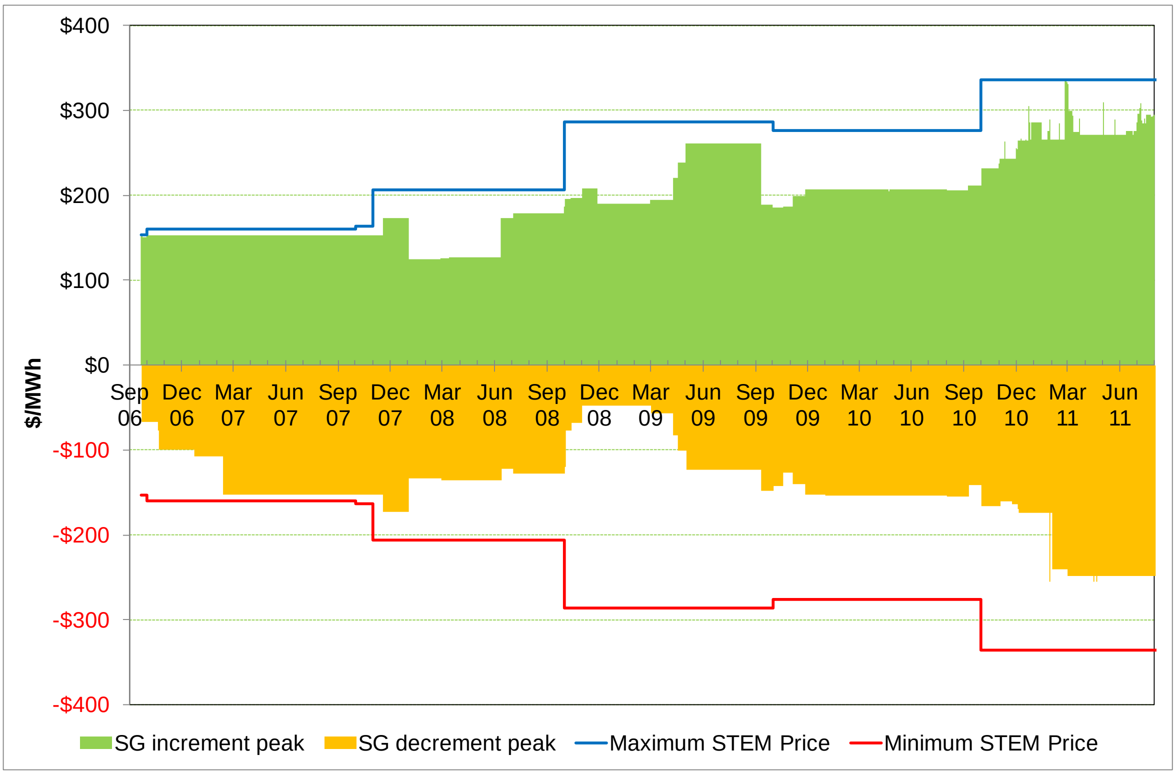
Balancing prices

Standing Data prices used in Balancing

Figure 59 illustrates average Standing Data Balancing prices for Non-Liquid Fuel facilities.[152]

[152] Average daily Standing Data Balancing prices for Non-Liquid Fuel facilities during peak and off-peak Trading Intervals are equal, or on average are less than one per cent different)for both increment and decrement prices) since market commencement. Since the magnitude of any difference is so small, only peak period prices have been presented.

Figure 59 Average Standing Data Balancing prices for Non-Liquid Fuel facilities (Peak)

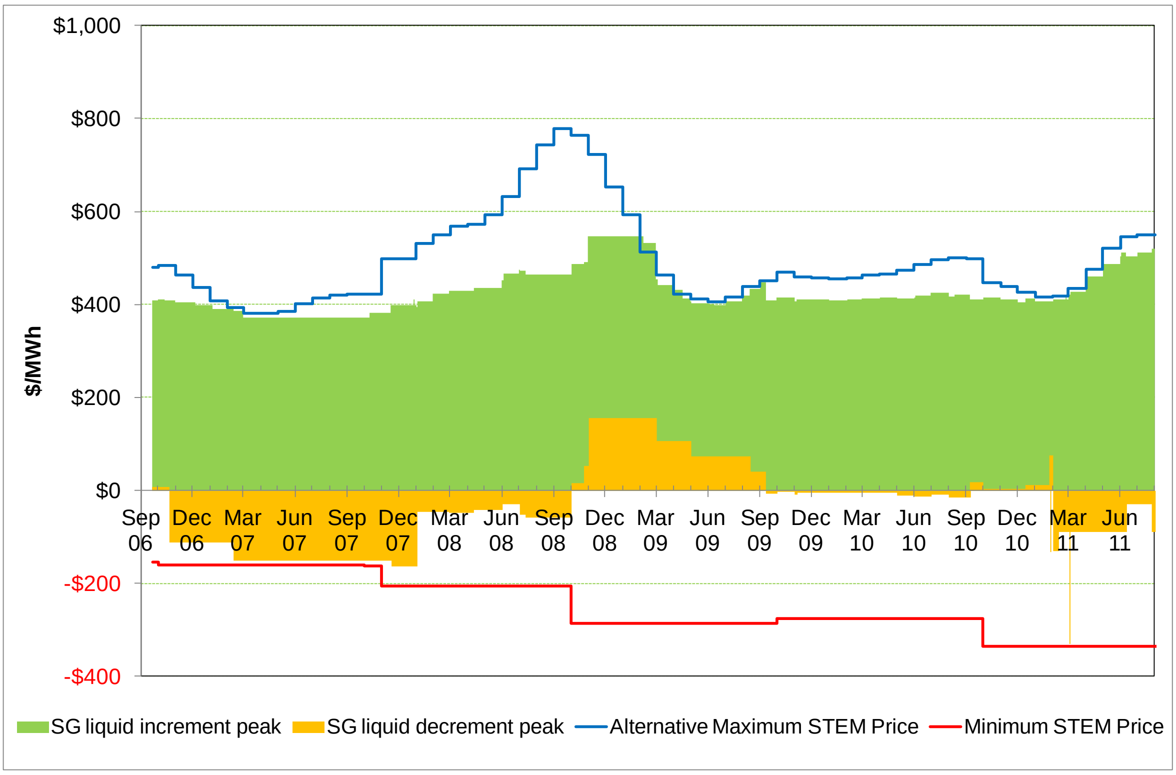


Broadly, IPPs want to be paid close to the applicable Maximum STEM Prices when instructed to increase generation from their Non-Liquid Fuelled facilities irrespective of the time of the day (on average, approximately $259/MWh for the Reporting Period). When instructed to 'back off' their Non-Liquid fuelled generation, IPPs are willing to pay either a low or high price for the energy they did not have to produce irrespective of the time of the day (on average, approximately $204/MWh for the Reporting Period).

Figure 60 illustrates average Standing Data Balancing prices for Liquid Fuel facilities.[153]

[153] Average daily Standing Data Balancing prices for Liquid Fuel facilities during peak and off-peak periods are equal, or on average are less than one per cent different (for both increment and decrement prices) since market commencement. Since the magnitude of any difference is so small, only peak period prices have been presented.

Figure 60 Average Standing Data Balancing prices for Liquid Fuel facilities (Peak)



Broadly, IPPs want to be paid close to the applicable Alternative Maximum STEM Prices when instructed to increase generation from their Liquid Fuelled facilities irrespective of the time of the day (on average, approximately $461/MWh for the Reporting Period). When instructed to 'back off' their Liquid fuelled generation, IPPs generally are willing to pay a low price for the energy they did not have to produce irrespective of the time of the day.

Figure 61 illustrates average Standing Data Balancing prices for Intermittent Generators during peak periods.

Figure 61 Average Standing Data Balancing prices for Intermittent Generators (Peak)

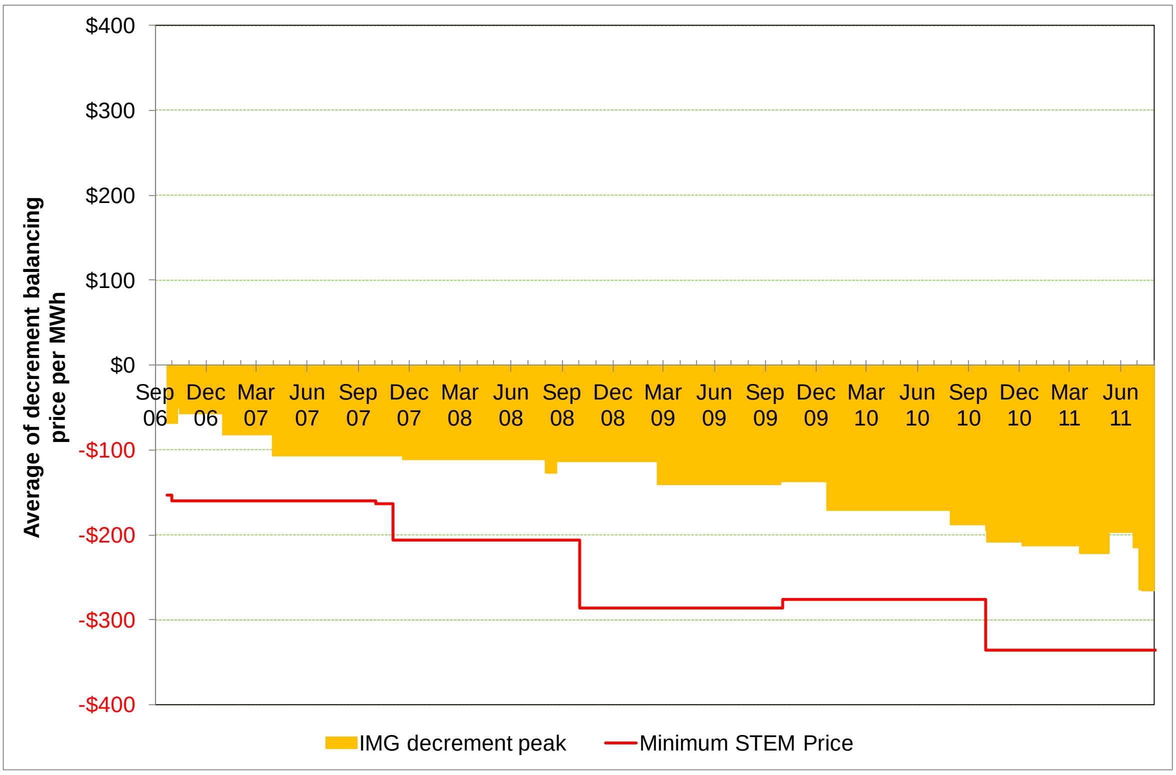
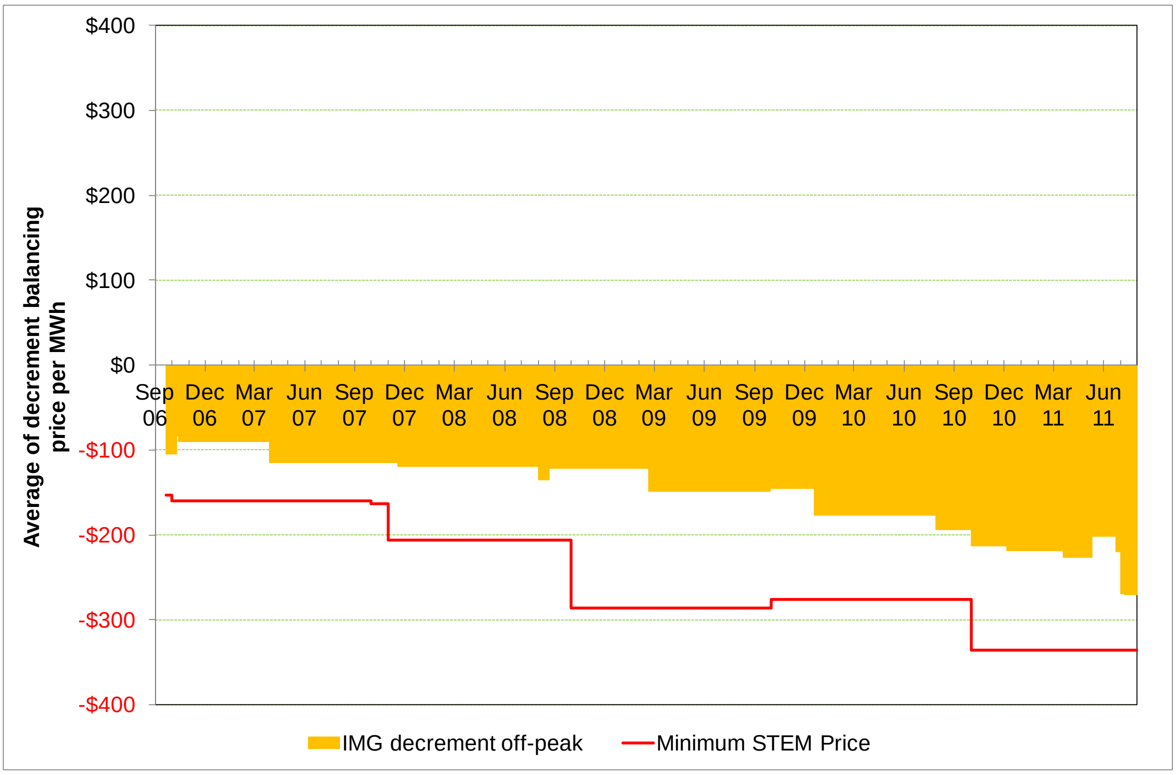


Figure 62 illustrates average Standing Data Balancing prices for Intermittent Generators during off-peak periods.

Figure 62 Average Standing Data Balancing prices for Intermittent Generators (Off-Peak)



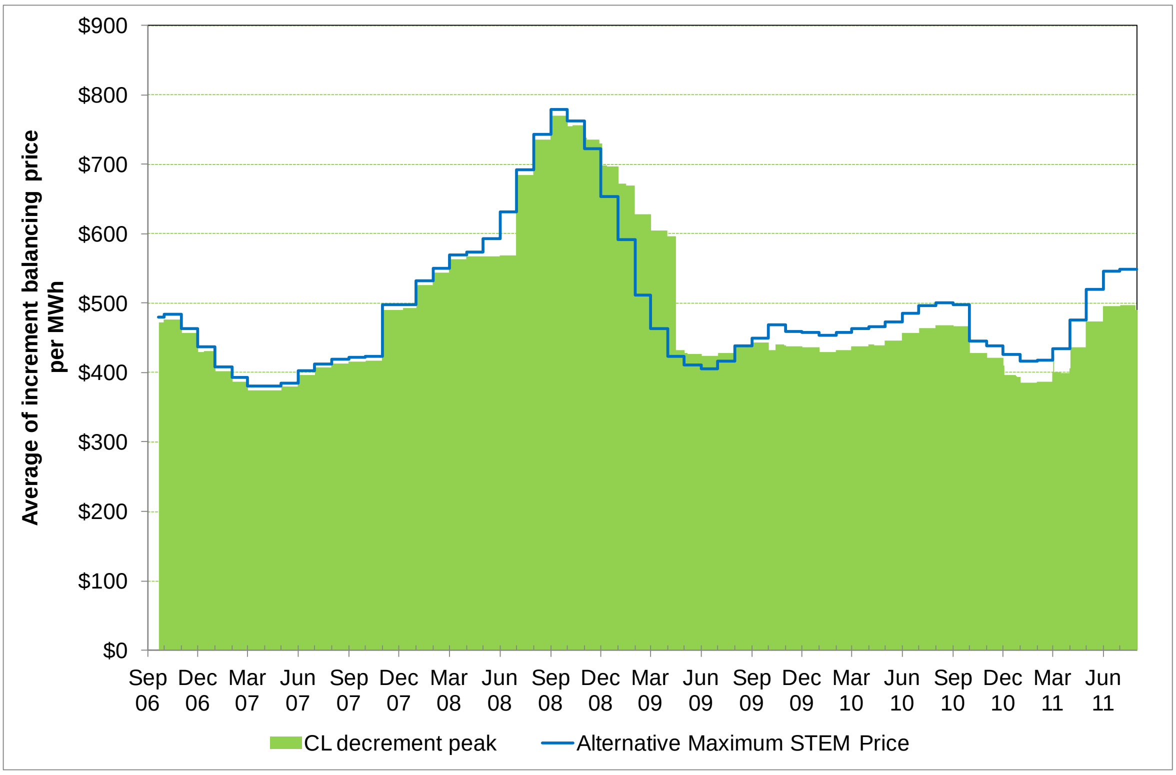
Broadly, during the Reporting Period IPPs wanted to be paid on average $212/MWh during Peak Trading Intervals and $217MWh during Off-Peak Trading Intervals when instructed to 'back off' their intermittent generation. This represents an average increase of $46/MWh and $58/MWh for peak and off-peak periods (respectively) when compared to the previous reporting period.

Figure 63 illustrates average Standing Data Balancing prices for Curtailable Loads.[154] [155]

[154] Average daily Standing Data Balancing prices for Curtailable Loads during peak and off-peak periods are equal, or on average are less than one per cent different since market commencement. Since the magnitude of any difference is so small, only peak period have been presented.

[155] In this figure, for consistency with the other figures relating to Standing Data Balancing prices, a reduction in Curtailable Loads is represented as an 'increment' of energy.

Figure 63 Average Standing Data Balancing prices for Curtailable Loads (Peak)



Broadly, Market Customers controlling Curtailable Loads want to be paid close to the applicable Alternative Maximum STEM Prices when instructed to curtail the applicable load (on average, approximately $436/MWh for the Reporting Period). This represents an average decrease of $6/MWh for peak period (respectively) when compared to the previous reporting period.

MCAP, UDAP and DDAP

Table 11 sets out the formulas prescribed in the Market Rules for calculating UDAP and DDAP.

Table 11 Method for calculating the UDAP and DDAP

Trading Interval	UDAP ($/MWh)	DDAP ($/MWh)
Off-Peak	0.00	1.1 * MCAP
Peak	0.5 * MCAP	1.3 * MCAP
Participant receives	Yes	
Participant pays		Yes

Figure 64 and Figure 65 compare 30-day and 90-day moving averages of peak STEM and Balancing prices, respectively.

Figure 64 30-day moving average Peak STEM and Balancing prices

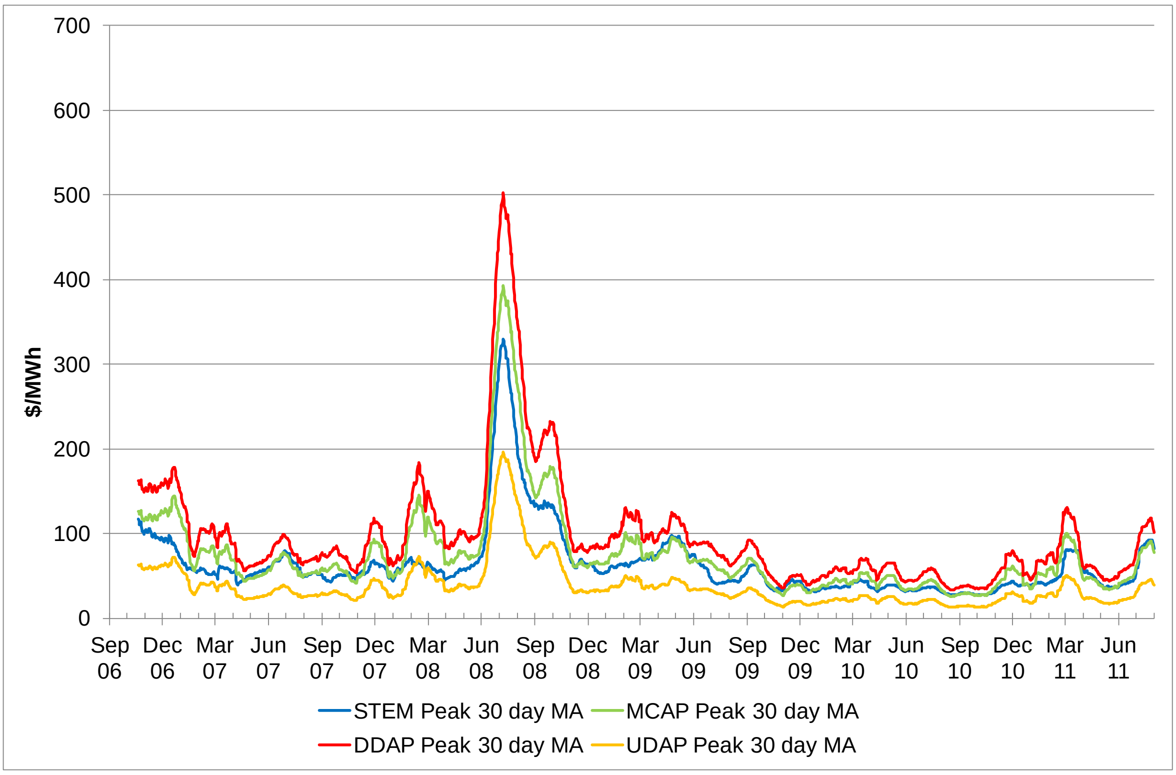


Figure 65 90-day moving average Peak STEM and Balancing prices

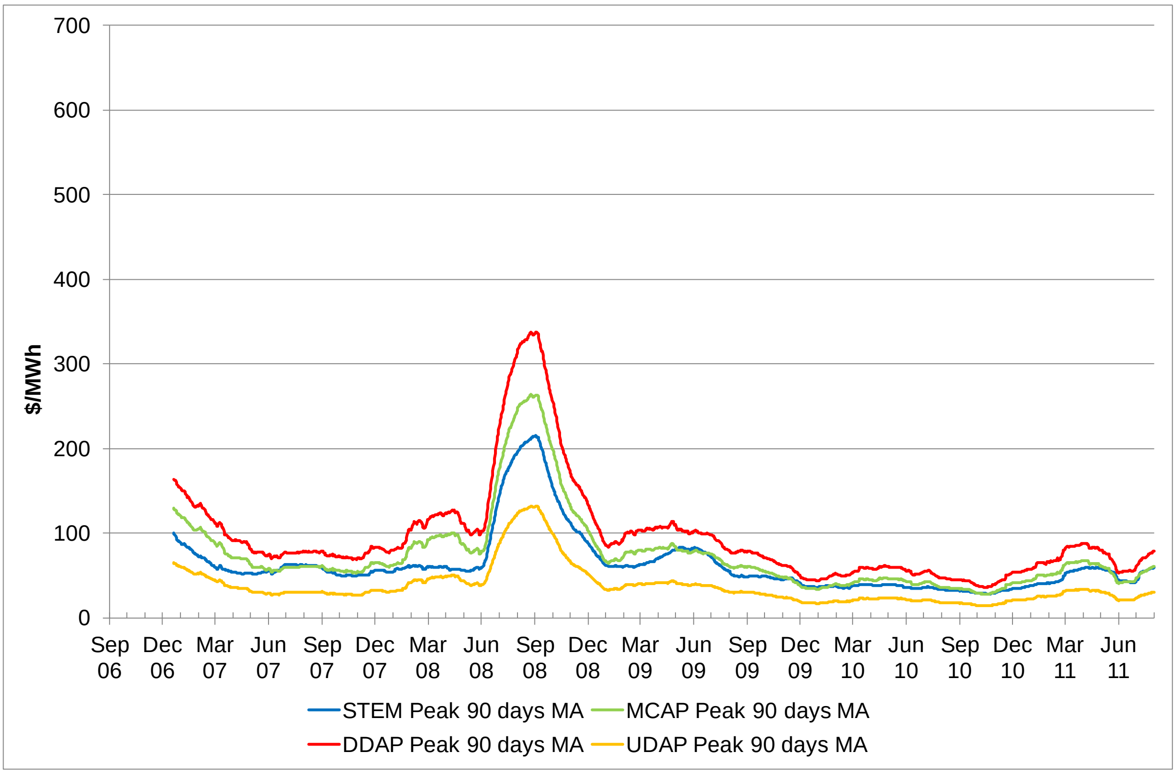


Figure 66 and Figure 67 compare 30-day and 90-day moving averages of off-peak STEM and Balancing prices, respectively.

Figure 66 30-day moving average Off-Peak STEM and Balancing prices

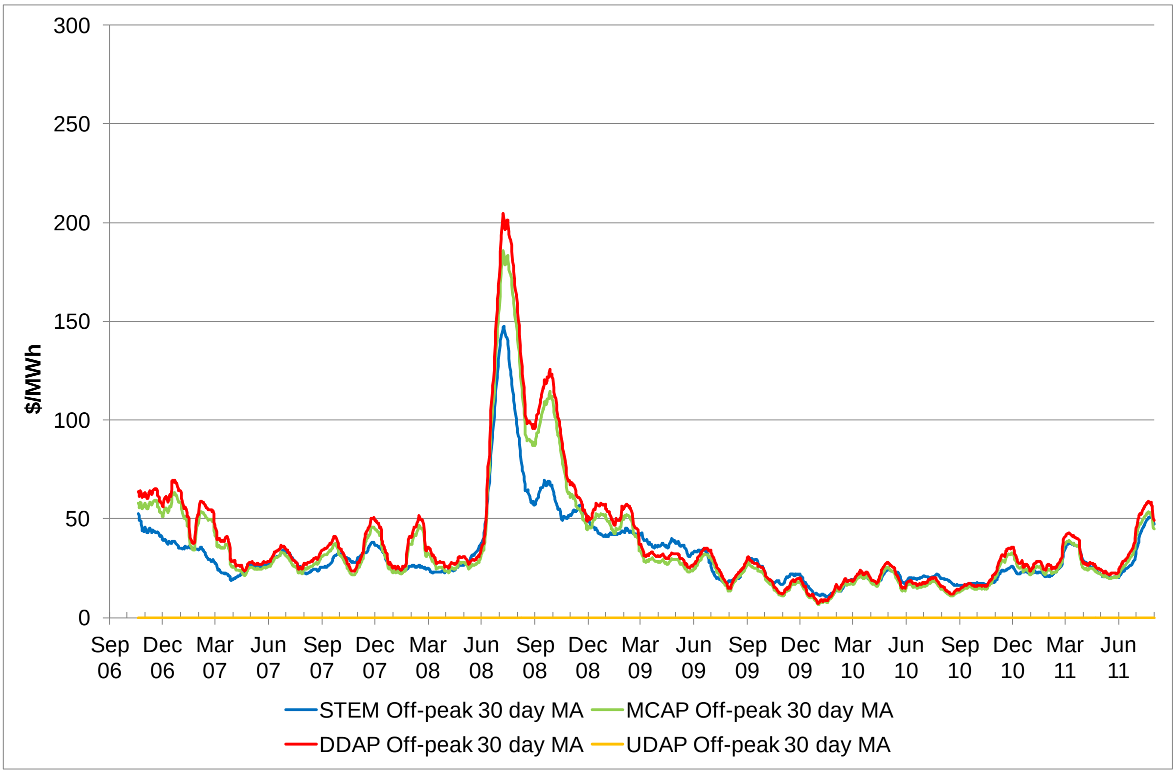


Figure 67 90-day moving average Off-Peak STEM and Balancing prices

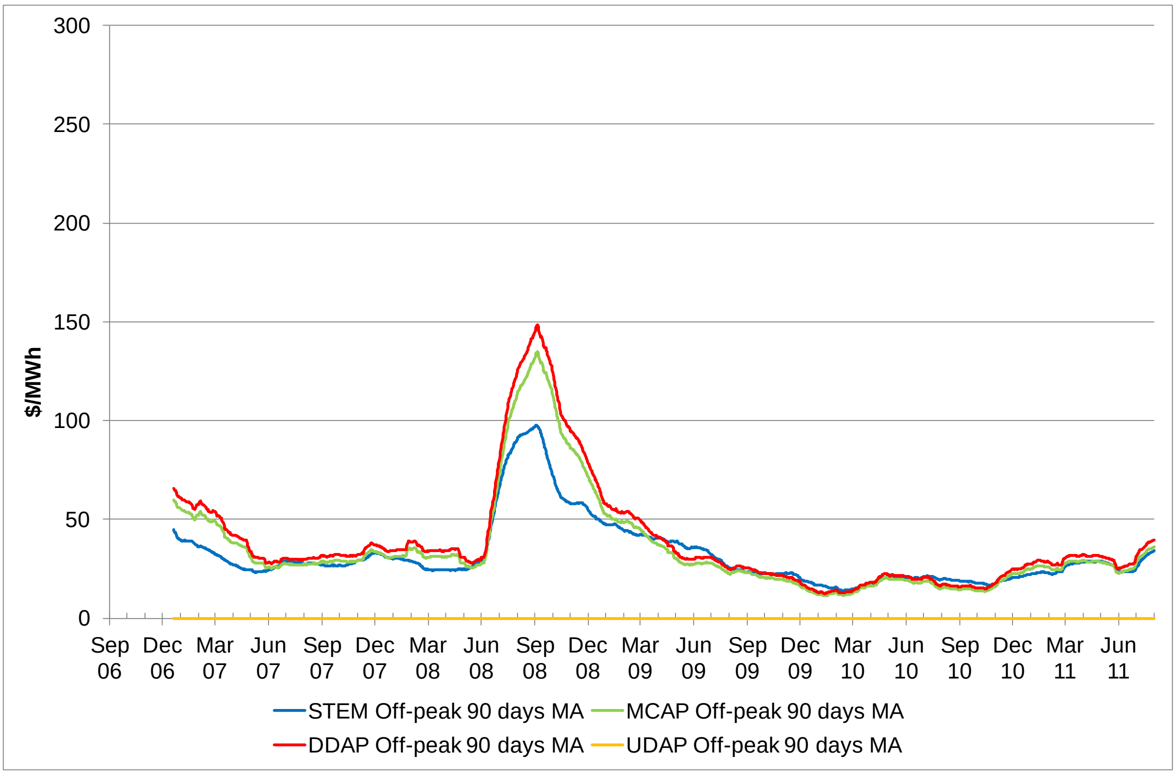


Figure 68 and Figure 69 show annual moving average STEM and Balancing prices for peak and off-peak periods, respectively.

Figure 68 Annual moving average Peak STEM and Balancing prices

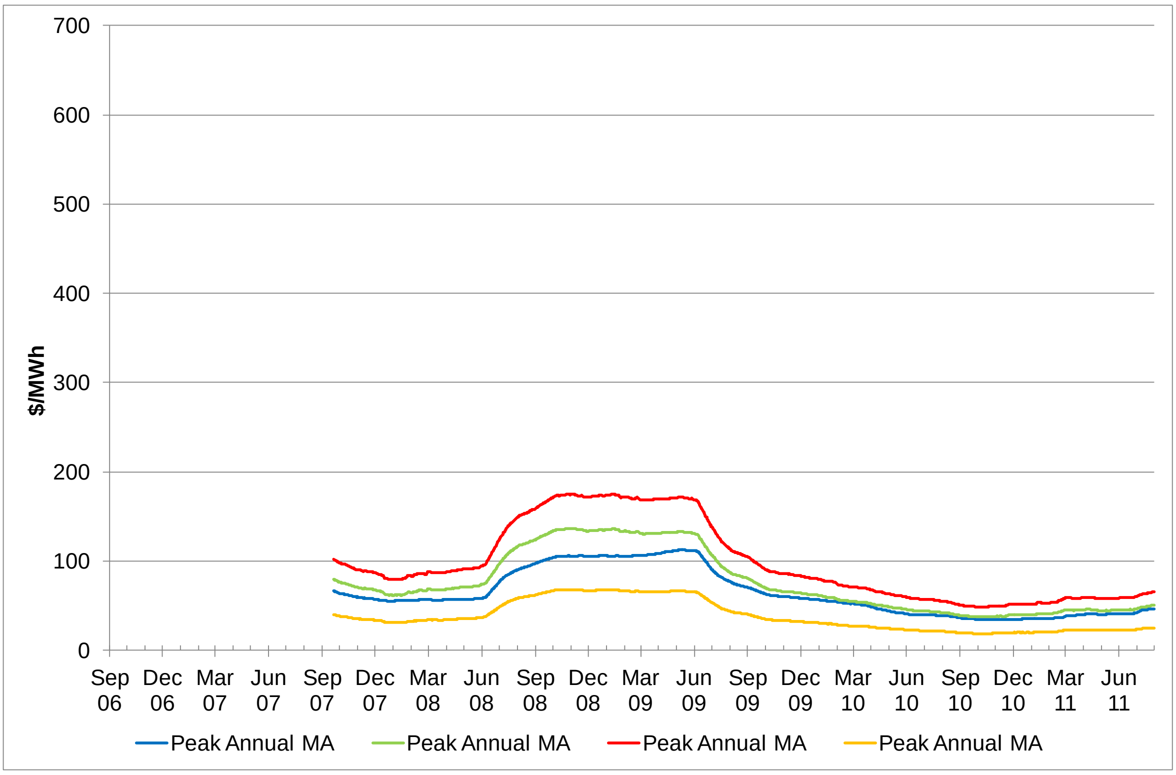
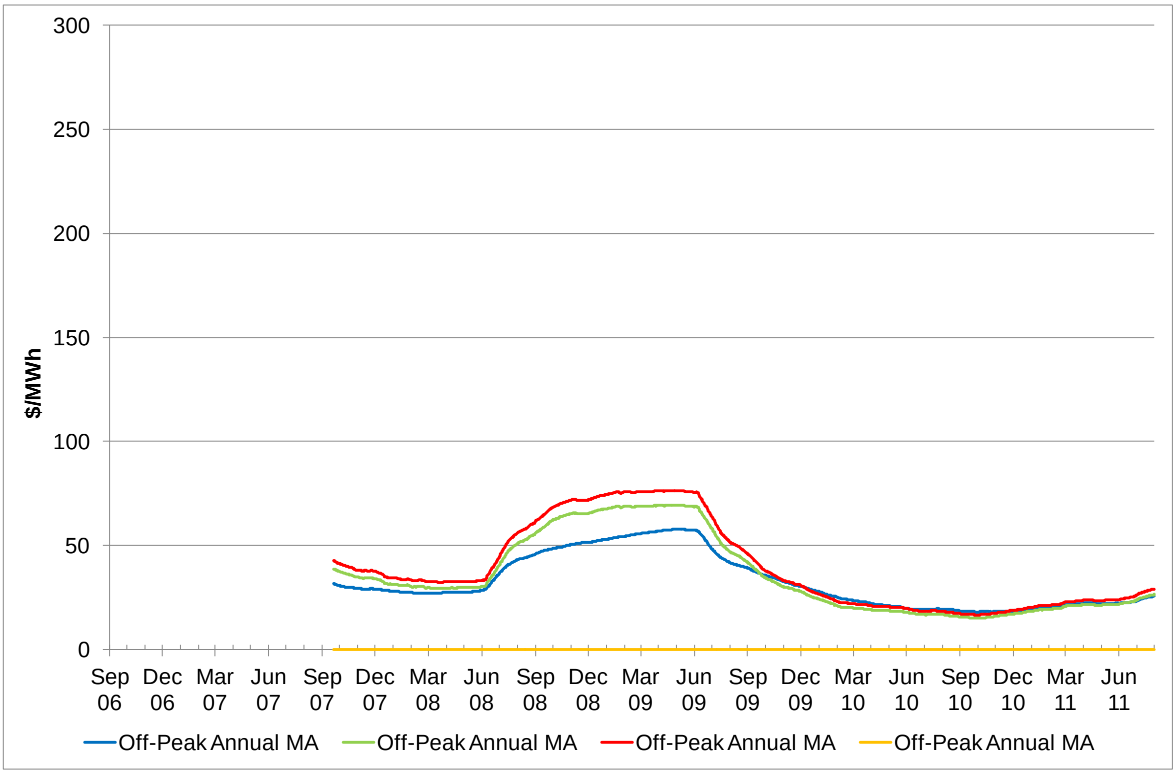


Figure 69 Annual moving average Off-Peak STEM and Balancing prices



Volatility of Balancing prices

Figure 70 to Figure 74 illustrate the means and standard deviations (as well as the maxima and minima) of Balancing prices.

Figure 70 Summary statistics for MCAPs during Peak Trading Intervals (per calendar month)

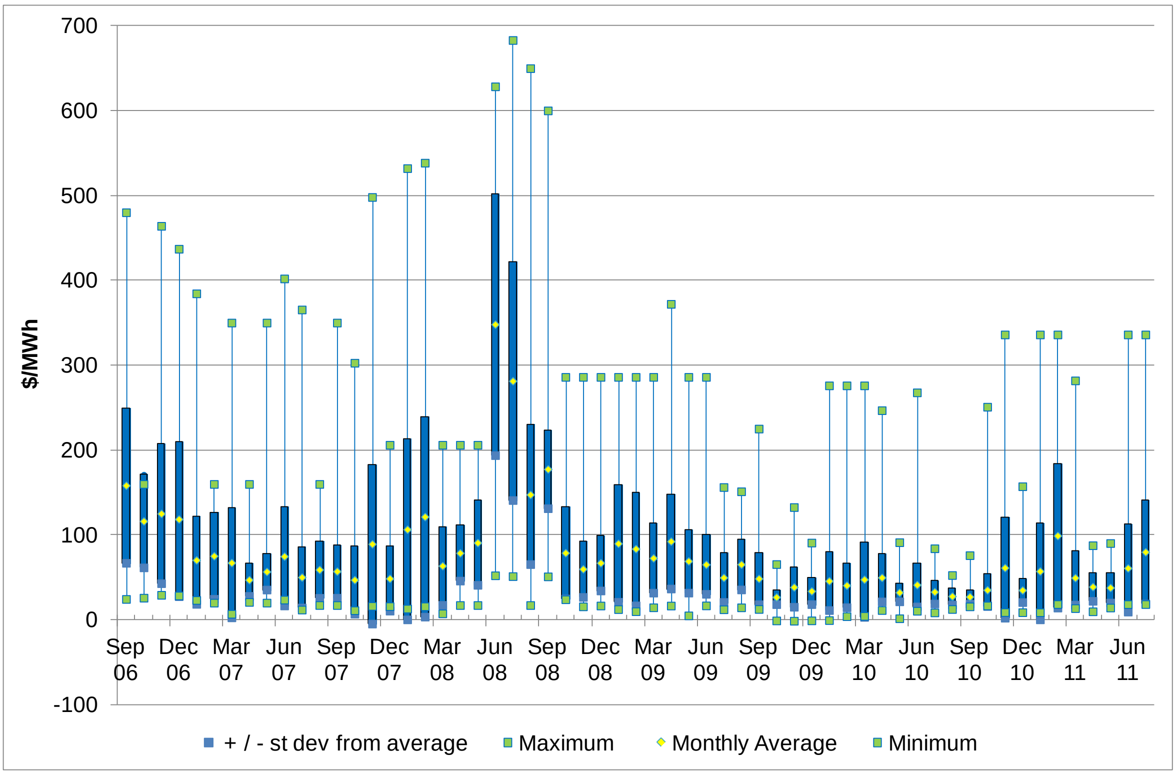


Figure 71 **Summary statistics for MCAPs during Off-Peak Trading Intervals (per calendar month)**

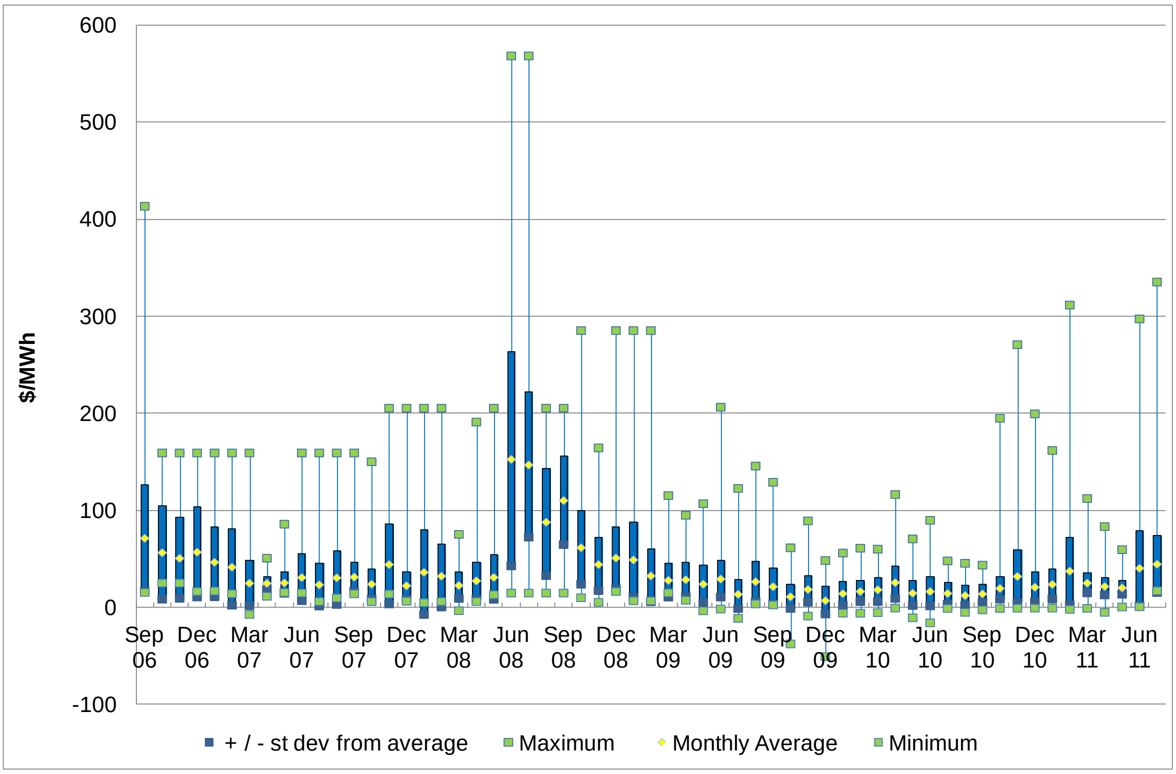


Figure 72 **Summary statistics for DDAPs during Peak Trading Intervals (per calendar month)**

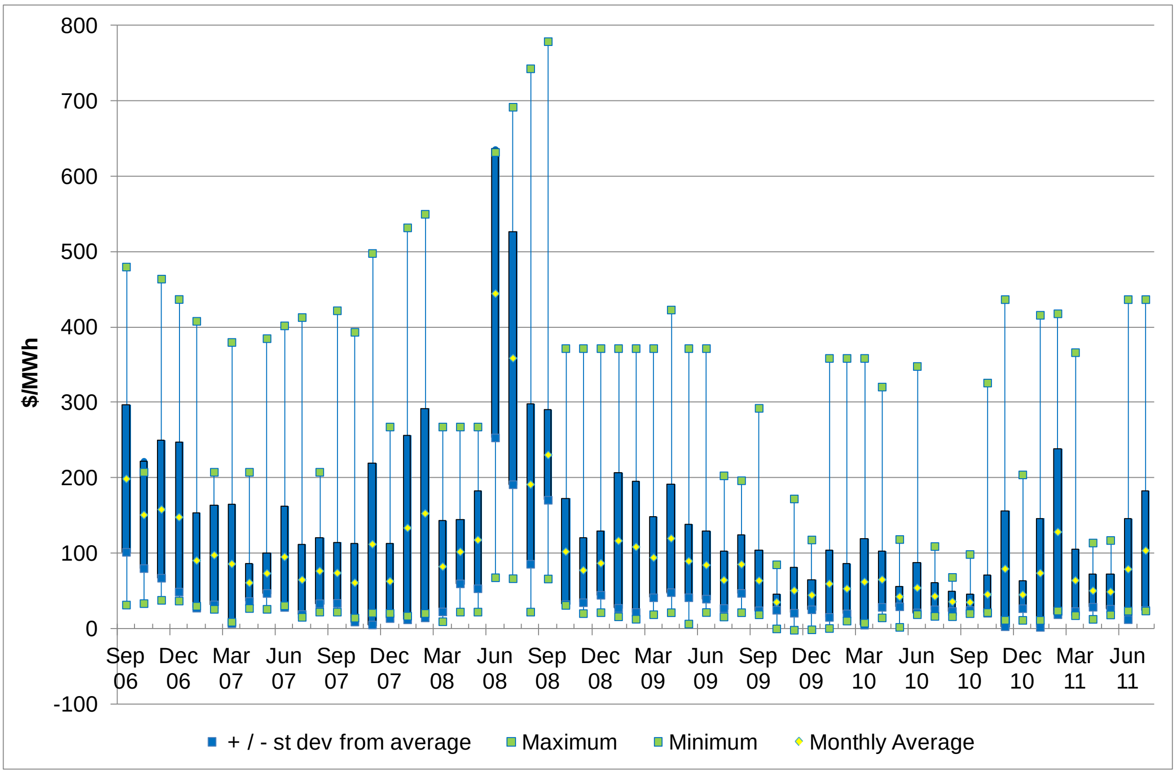


Figure 73 Summary statistics for DDAPs during Off-Peak Trading Intervals (per calendar month)

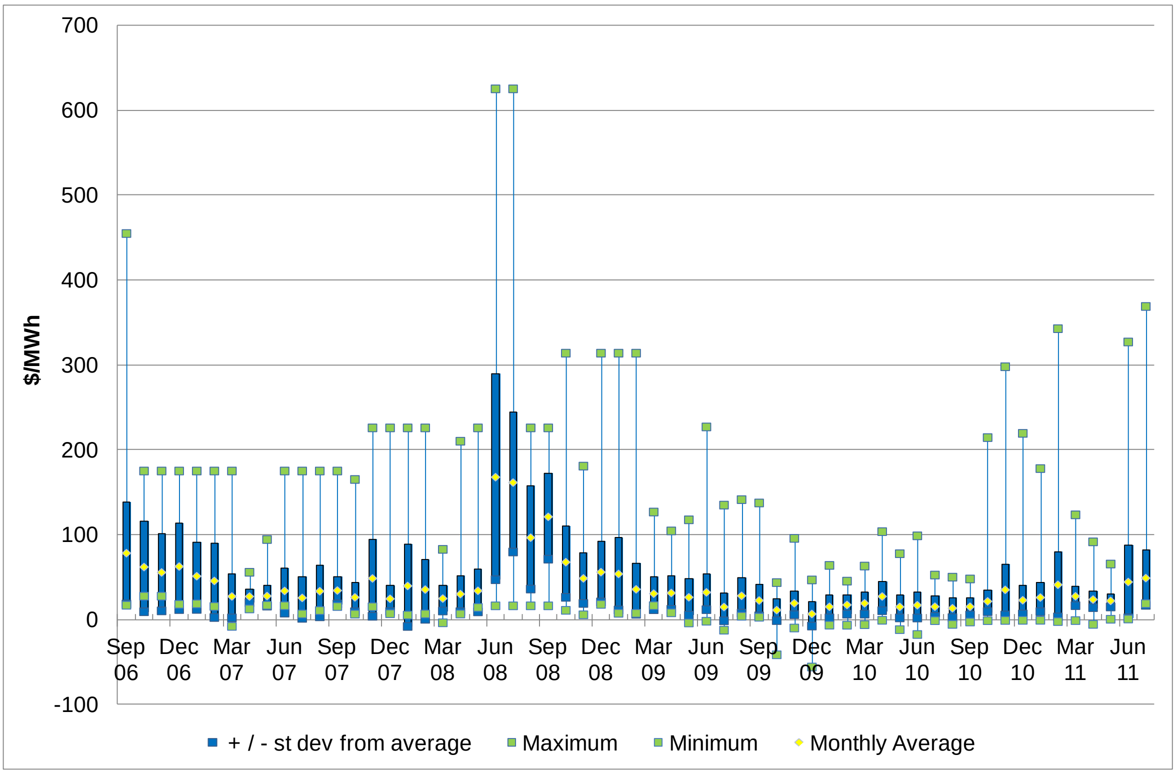
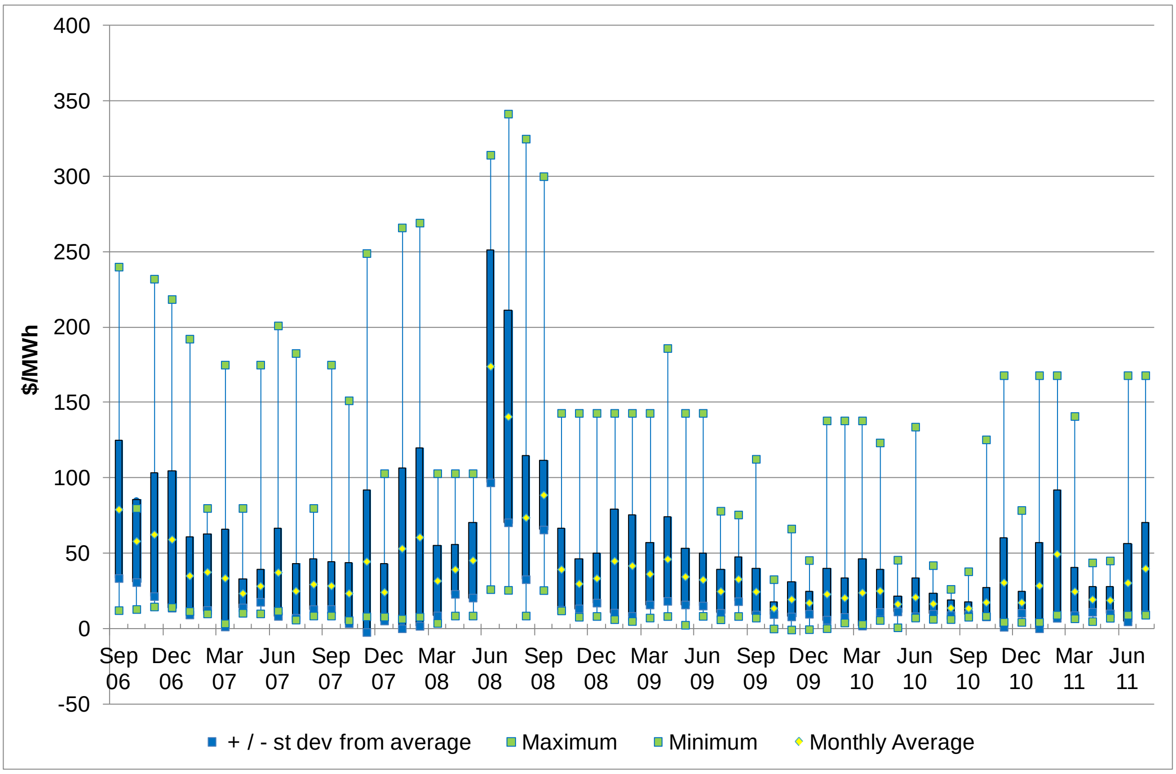


Figure 74 Summary statistics for UDAPs during Peak Trading Intervals (per calendar month)



High Balancing prices

Figure 75 and Figure 76 illustrate the price duration curves for MCAPs during peak and off-peak periods for 21 September 2006 to 31 July 2011.

Figure 75 shows that DDAPs are significantly higher than the STEM prices in peak period across all the Trading Intervals from market commencement.

Figure 75 Price duration curves for STEM Clearing Prices, MCAPs, UDAPs and DDAPs during Peak periods (21 September 2006 to 31 July 2011)

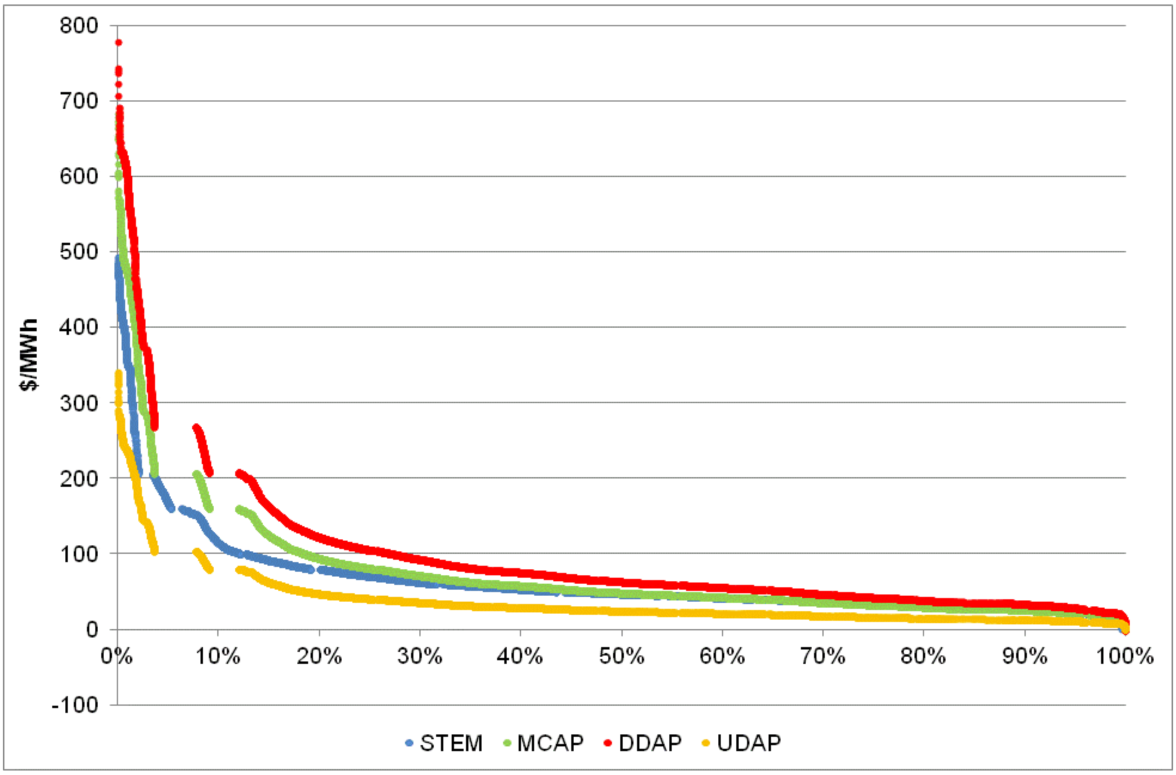


Figure 76 shows that during off-peak periods, the majority of DDAPs occur in a broad range below $100/MWh (between $100/MWh and negative $55/MWh) for approximately 94 per cent of the total Off-peak Trading Intervals, with a fairly even distribution of prices within this range. For about 60 per cent of the total Trading Intervals, DDAPs were closely aligned with MCAP and STEM Clearing Prices, and for 14 per cent of the total Trading Intervals DDAP and MCAP were lower than STEM Clearing Prices.

Figure 76 Price duration curves for STEM Clearing Prices, MCAPs, UDAPs and DDAPs during Off-Peak periods (21 September 2006 to 31 July 2011)

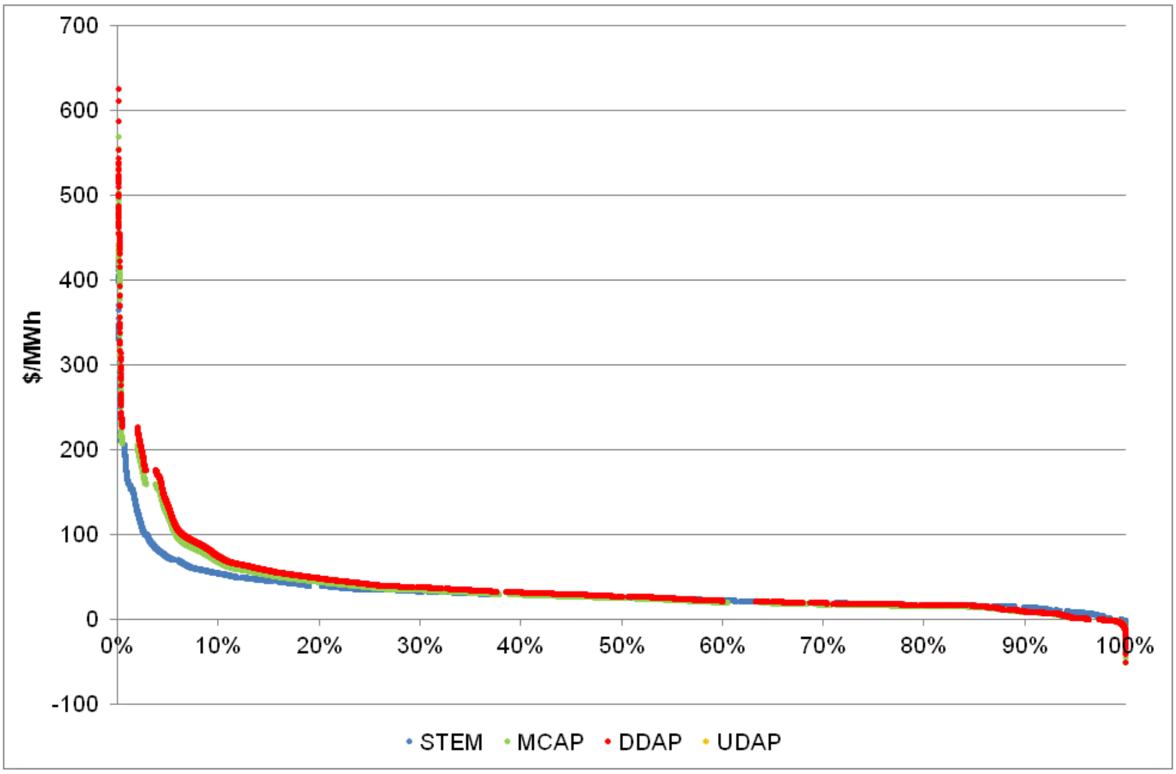


Figure 77 and

Figure 78 illustrate price duration curves for MCAPs during Peak periods, for the periods 1 August 2009 to 31 July 2010 and 1 August 2010 to 31 July 2011, respectively.

Figure 77 **Price duration curves for STEM Clearing Prices and MCAPs during Peak periods (01 August 2009 to 31 July 2010)**

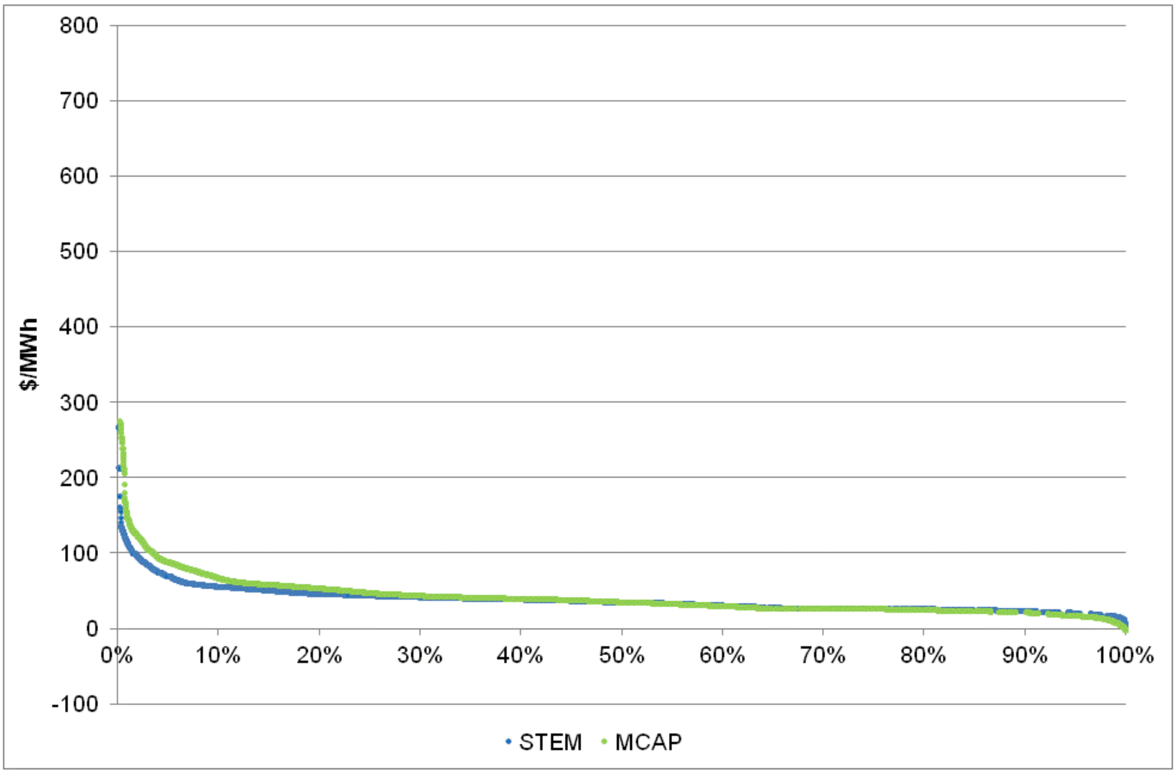
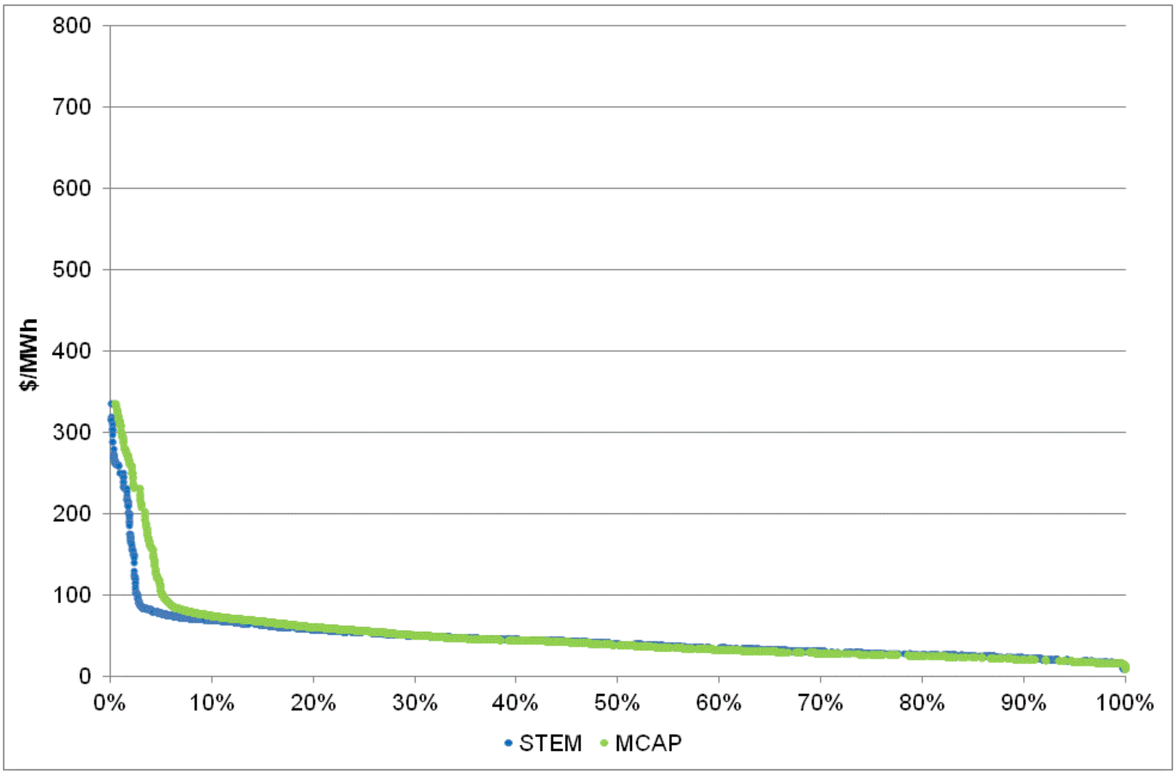


Figure 78 **Price duration curves for STEM Clearing Prices and MCAPs during Peak periods (01 August 2010 to 31 July 2011)**



Registered Market Generators and Market Customers

Table 12 Registered Market Generators and Market Customers

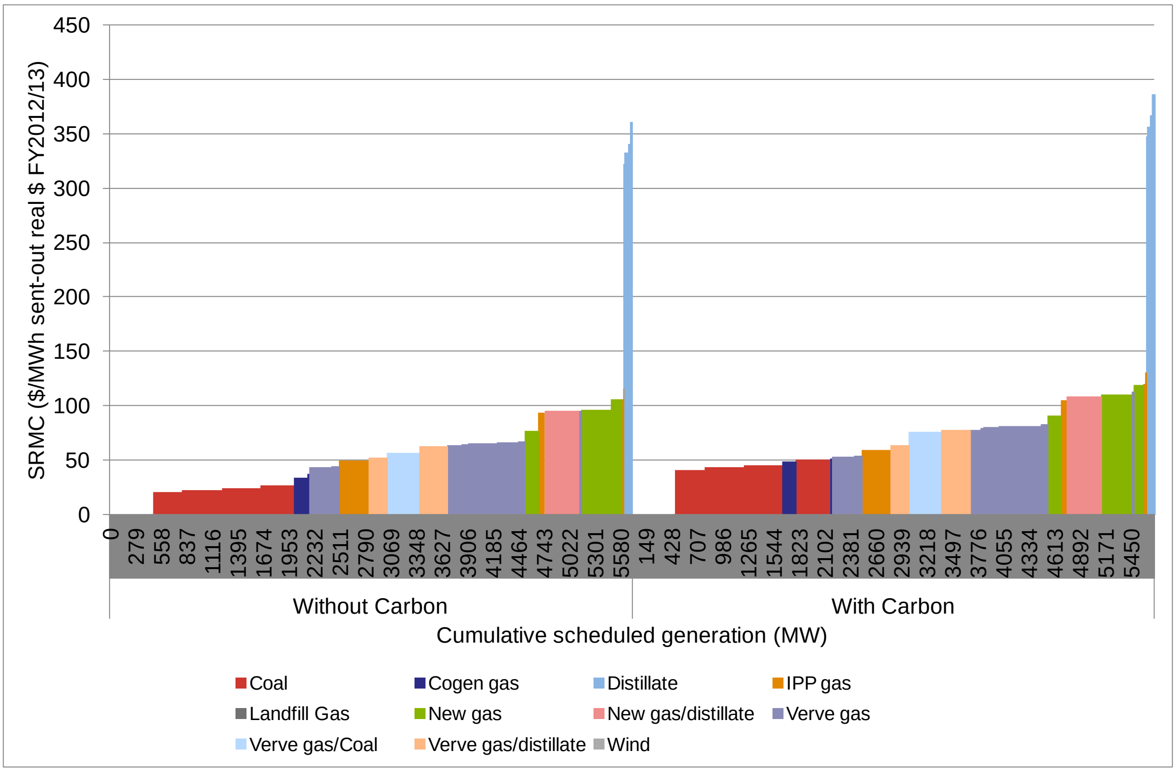
	2 September 2008	6 October 2009	14 October 2010	3 October 2011
Market Generators and Market Customers	Alcoa of Australia Limited Alinta Sales Pty Ltd Griffin Power Pty Ltd Griffin Power 2 Pty Ltd Landfill Gas and Power Pty Ltd Perth Energy Pty Ltd Southern Cross Energy Verve Energy	Alcoa of Australia Limited Alinta Sales Pty Ltd Griffin Power Pty Ltd Griffin Power 2 Pty Ltd Landfill Gas and Power Pty Ltd Perth Energy Pty Ltd Southern Cross Energy Verve Energy	Alcoa of Australia Limited Alinta Sales Pty Ltd Griffin Power Pty Ltd Griffin Power 2 Pty Ltd Landfill Gas and Power Pty Ltd Metro Power Company Pty Ltd Perth Energy Pty Ltd Southern Cross Energy Verve Energy	Alcoa of Australia Limited Alinta Sales Pty Ltd Griffin Power 2 Pty Ltd Griffin Power Pty Ltd Landfill Gas and Power Pty Ltd Metro Power Company Pty Ltd Perth Energy Pty Ltd Southern Cross Energy Tiwest Verve Energy
Market Generators (only)	Biogen Coolimba Power Pty Ltd EDWF Manager Pty Ltd Eneabba Gas Limited Eneabba Energy Pty Ltd Goldfields Power Pty Ltd Mount Herron Engineering Pty Ltd Namarkkon Pty Ltd NewGen Power Kwinana Pty Ltd NewGen Neerabup Pty Ltd SkyFarming Pty Ltd Wambo Power Ventures Pty Ltd Waste Gas Resources Pty Ltd Western Australia Biomass Pty Ltd	Biogen Collgar Wind Farm Coolimba Power Pty Ltd EDWF Manager Pty Ltd Eneabba Gas Limited Eneabba Energy Pty Ltd Goldfields Power Pty Ltd Mount Herron Engineering Pty Ltd Namarkkon Pty Ltd NewGen Power Kwinana Pty Ltd NewGen Neerabup Pty Ltd NewGen Neerabup Partnership SkyFarming Pty Ltd Tesla Corporation Pty Ltd Vinalco Energy Pty Ltd Wambo Power Ventures Pty Ltd Waste Gas Resources Pty Ltd Western Australia Biomass Pty Ltd Western Energy Pty Ltd	Advanced Energy Resources Biogen Collgar Wind Farm Coolimba Power Pty Ltd EDWF Manager Pty Ltd Eneabba Gas Limited Eneabba Energy Pty Ltd Goldfields Power Pty Ltd McNabb Plantation Alliance Pty Ltd Mount Herron Engineering Pty Ltd Namarkkon Pty Ltd NewGen Power Kwinana Pty Ltd NewGen Neerabup Pty Ltd NewGen Neerabup Partnership SkyFarming Pty Ltd Tesla Corporation Pty Ltd Vinalco Energy Pty Ltd Wambo Power Ventures Pty Ltd Waste Gas Resources Pty Ltd	Advanced Energy Resources Biogen Blair Fox Pty Ltd Collgar Wind Farm Coolimba Power Pty Ltd EDWF Manager Pty Ltd Eneabba Energy Pty Ltd Eneabba Gas Limited Goldfields Power Pty Ltd McNabb Plantation Alliance Pty Ltd Merredin Energy Mount Herron Engineering Pty Ltd Mt.Barker Power Company Pty Ltd Mumbida Wind Farm Pty Ltd Namarkkon Pty Ltd NewGen Neerabup Partnership NewGen Neerabup Pty Ltd NewGen Power Kwinana Pty Ltd SkyFarming Pty Ltd

	2 September 2008	6 October 2009	14 October 2010	3 October 2011
			Western Australia Biomass Pty Ltd Western Energy Pty Ltd	Tesla Corporation Management Pty Ltd Tesla Corporation Pty Ltd Tesla Geraldton Pty Ltd Tesla Holdings Tesla Kemerton Pty Ltd Tesla Northam Pty Ltd Vinalco Energy Pty Ltd Walkaway Wind Power Pty Ltd Wambo Power Ventures Pty Ltd Waste Gas Resources Pty Ltd Western Australia Biomass Pty Ltd Western Energy Pty Ltd
Market Customers (only)	Barrick (Kanowna) Limited Clear Energy Pty Ltd Energy Response Pty Ltd Karara Energy Pty Ltd Newmont Power Pty Ltd Premier Power Sales Pty Ltd Synergy Water Corporation	Barrick (Kanowna) Limited Clear Energy Pty Ltd DMT Energy Energy Response Pty Ltd Karara Energy Pty Ltd Newmont Power Pty Ltd Premier Power Sales Pty Ltd Synergy Water Corporation	Amanda Australia Pty Ltd Barrick (Kanowna) Limited Clear Energy Pty Ltd DMT Energy Energy Response Pty Ltd EnerNOC Australia Pty Ltd ERM Power Retail Pty Ltd Karara Energy Pty Ltd Newmont Power Pty Ltd Premier Power Sales Pty Ltd Synergy Water Corporation	Amanda Australia Pty Ltd Barrick (Kanowna) Limited Clear Energy Pty Ltd DMT Energy Energy Response Pty Ltd EnerNOC Australia Pty Ltd ERM Power Retail Pty Ltd Karara Energy Pty Ltd Newmont Power Pty Ltd Premier Power Sales Pty Ltd Synergy Water Corporation

Appendix 4 Impact analysis of carbon price in the Wholesale Electricity Market

Figure 79 shows the merit order in Western Australia in 2012/13 with and without a carbon price.[156] This shows that the SRMC for all non-renewable plant increases as a result of the introduction of a carbon price. However, there are no material changes in the relative position in the merit order of each technology type as a result of the introduction of a carbon price.

Figure 79 Merit order with and without carbon price



[156] Figure 79 relies on cost data used to determine the margin values for 2012/13. See: SKMMMA, *2011 Margin Peak and Margin Off-Peak Review*, Assumptions and Methodology Report, 5 October 2011.

Appendix 5 Overview of Demand Side Management arrangements in other markets

National Electricity Market (NEM)

The NEM is a compulsory energy-only market. That is, all generators that do not supply all of their output to a local retailers or a co-located load must sell it is the wholesale spot market. Bilateral contracting can occur between market participants but this will typically take the form of financial hedging contracts that are traded in parallel to the spot market. The Australian Energy Market Operator (**AEMO**) is responsible for dispatching the market. AEMO forecasts demand for each dispatch interval so that it can determine how much electricity needs to be dispatched. AEMO then dispatches generation and DSM in order to achieve least cost dispatch.

Electricity customers can provide DSM in the NEM by registering with AEMO as a scheduled load and bidding in the market to reduce demand. Based on these bids, AEMO will dispatch a scheduled load (to reduce load) when it is cheaper than dispatching a generator (to increase generation).

Where scheduled loads are dispatched by AEMO, they avoid paying the spot price to the extent that they have reduced their demand. That is, remuneration for scheduled loads in the NEM is on the basis of a reduction in cost, not additional revenue.

Electricity customers can also provide DSM indirectly by contracting with their retailers to reduce load at peak times in order to reduce their retailer's exposure to high wholesale prices.

New Zealand

The New Zealand electricity market is a compulsory energy-only market, similar in many ways to the NEM.

The New Zealand Electricity Authority (**NZEA**) has recently proposed the implementation of a new demand side bidding and forecasting (**DSBF**) framework. Under this framework, the intention is to allow DSM initially in certain specified areas of the network.

Under the DSBF framework, a purchaser in one of the specified areas of the network may apply to the system operator for the right to submit bids for DSM for a particular electricity-using device or group of devices, called a dispatch-capable load station (**DCLS**). Once a DCLS is approved, the purchaser must submit a nominated bid to reduce load in every trading period. A nominated bid can have several bid bands sorted in decreasing order of price. If a DCLS is dispatched, the purchaser will receive dispatch instructions for the DCLS for that trading period based on the dispatch bid. The NZEA has noted that it expects the DSBF framework would be likely to attract participation from at least one or two large electricity users.

Singapore

The National Electricity Market of Singapore (**NEMS**) is very similar in design to the NEM. The market is a compulsory energy-only market. The Energy Market Company (**EMC**) is responsible for dispatching the market.

There is an Interruptible Load (IL) scheme that operates in NEMS. The IL scheme allows DSM to participate in the near-real time spinning reserve market. This enables consumers to voluntarily choose to have their electricity supply interrupted in exchange for reserve payments, thereby competing directly with generating plants in the reserve market. Depending on the types of reserves the consumers intend to participate in, these ILs should either be disconnected automatically once the system frequency reaches a preset threshold or manually disconnected by the IL provider when instructed within stipulated timeframes. To ensure inadvertent non-performance of ILs does not compromise power system security, the power system operator estimates the amount of ILs that can safely be scheduled as reserve. This is reviewed annually.

Great Britain

The British Electricity Trading and Transmission Arrangements (BETTA) is the energy market that operates in Great Britain. BETTA is a 'net' market meaning that most electricity is traded bilaterally or through decentralised power exchanges. However, ELEXON is responsible for metering and settling market participants in the Balancing Mechanism.

In principle, there is nothing to stop the DSM providers participating in bilateral trading. However, no information is available on whether this occurs.

DSM does occur in the Balancing Mechanism, which was specifically designed from the outset to allow this to occur. DSM providers have to provide information on their intended level of consumption during the settlement period and the price and extent to which they are prepared to move away from this level. If their offer is accepted, they are paid their offer price for the energy they do not consume.

PJM

The PJM market is a regional wholesale market that operates across 13 states (and the District of Columbia) in the eastern United States, including Pennsylvania, New Jersey and Maryland. The PJM market has an energy market, which operates both day-ahead and in real time, and also has a centralised forward capacity market. This forward capacity market is based on making capacity commitments three years ahead. Of the markets reviews, the PJM is most similar to the design of the WEM.

Within the PJM, DSM can be offered either on an economic basis or as part of an emergency program.

Economic DSM – that which is called based on bids into the energy market – is completely integrated into PJM's energy market. Economic DSM can be bid in to either the day-ahead or real-time markets. There is no requirement for a firm commitment to reduce a specific amount of electricity consumption, although PJM requires a reasonably accurate estimate to effectively operate the grid.

Emergency DSM programs are those used by PJM only in the event of a pre-defined triggering event that is considered to be an emergency. To be available for Emergency DSM, the resource must be available to respond to PJM's request to reduce load for up to 10 days during the summer, where each request may be up to six hours in duration. The revenue stream derived from participation in the emergency program is largely driven by the capacity market. The revenue earned is a function of the relevant capacity price and the load reduction commitment. The resource is paid to be "available" during expected emergency conditions on a monthly basis for a commitment that is made for one year.

Appendix 6 Overview of governance arrangements in other markets

National Electricity Market (NEM)

Market overview	The NEM has annual energy consumption of around 196 TWh and installed generation of around 47,000 MW.
Policy	The Standing Council on Energy and Resources (**SCER**) under the auspice of the Council of Australian Governments (**COAG**) is the national policy and governance body.
Rule changes	The Australian Energy Market Commission (**AEMC**) is responsible for making changes to the National Electricity Rules (**NER**) that govern the NEM in accordance with the National Electricity Objective and other provisions in the National Electricity Law (**NEL**). However, the AEMC cannot initiate rule changes if its own choosing – it must base its decisions on rule change proposals submitted by other parties. The AEMC is responsible to COAG through the SCER.
Market and system operator and network planner	The Australian Energy Market Operator (**AEMO**) is responsible for management of the NEM, including spot market operation and power system security. AEMO is also responsible for publishing information about network and plant availability over different timeframes. Finally, AEMO is responsible for national transmission planning, although State and Territory transmission providers maintain responsibility for jurisdictional network planning.
Regulators	The Australian Energy Regulator (**AER**) is responsible for carrying out economic regulation of electricity networks and for enforcing compliance with the National Electricity Law and Rules. The AER is accountable to the Commonwealth Government as a constituent entity of the Australian Competition and Consumer Commission (**ACCC**). The ACCC retains responsibility for competition related matters. State and Territory regulators have responsibility for retail price regulation and some aspects of non-economic regulation such as distributor service standards.

New Zealand

Market overview	The NZ electricity market has annual energy consumption of around 40 TWh and installed capacity of around 9,000 MW.
Policy	Ministry of Economic Development.
Rule changes	The wholesale market for electricity operates under the Electricity Industry Participation Code, and is overseen by the market regulator, the New Zealand Electricity Authority (**NZEA**). The NZEA has responsibility for developing and enforcing the Code.
Market operator	The market operation is managed by several service providers under agreements with the NZEA. The physical operation of the power system is managed by Transpower in its role as System Operator. The NZEA contracts out the services required to run the electricity market. The Reconciliation Manager, who reconciles all metered quantities, Pricing Manager, who determines the final prices at each node, and Clearing and Settlement Manager, who pays generators for their generation at the market clearing price and invoices all retailers for their off-take, are all contracted to the New Zealand Exchange.
System operator	The grid owner and operator is Transpower, a state-owned enterprise responsible for ensuring electricity supply security and quality. Transpower also takes on the roles of scheduler, predicting likely demand to help generators make bids, and dispatcher, in charge of matching demand and supply in real time.
Regulators	The wholesale market for electricity operates under the Electricity Industry Participation Code, and is overseen by the NZEA. The NZEA monitors and reports on market performance. The Commerce Commission is New Zealand's competition enforcement and regulatory agency (including, grid investment approval and price regulation).

Singapore

Market overview	The National Electricity Market of Singapore (NEMS) has annual energy consumption of around 45 TWh and generation capacity of around 12,000 MW.
Policy	Ministry of Trade and Industry, Energy Division has the responsibility for formulating energy policies and strategies.
Rule changes	The NEMS is established under the authority of the Electricity Act, and is largely governed by that Act. In addition, it is governed by the wholesale market rules and associated manuals and by the electricity licences and codes of practice issued by the Energy Market Authority (**EMA**). The EMA was responsible for making the initial set of wholesale market rules which, along with market manuals, the system operation manual and specific market-related agreements, provide for the establishment and operation of the wholesale electricity market.
Market operator	The Energy Market Company (**EMC**) operates and administers the wholesale markets. EMC is majority owned by EMA.
System operator	The Power System Operator (**PSO**), a division of the EMA, is responsible for ensuring the reliable supply of electricity to consumers and the secure operation of the power system. The PSO controls the dispatch of facilities in the wholesale market, coordinates outage and emergency planning and directs the operation of the Singapore high-voltage transmission system under the terms of an “operating agreement” with SP PowerAssets, the transmission licensee.
Regulators	The Electricity Act allocates to the EMA responsibility for regulation of the electricity sector.

Great Britain

Market overview	The British Electricity Trading and Transmission Arrangements (BETTA) market has annual energy consumption of around 384 TWh and total generation capacity of around 90,000 MW.
Policy	Department of Energy and Climate Change.
Rule changes	The formal rules of BETTA are set out in codes which cover different aspects of the relationship between generators, retailers and the transmission companies. Changes to the codes are proposed by one or more companies, endorsed (or not) by an industry panel, and decided by the industry’s regulator (the Gas and Electricity Markets Authority operating through the Office of Gas and Electricity Markets (Ofgem)), with the possibility of appeal if the regulator goes against the panel’s recommendation.
Market operator	BETTA is a ‘net’ market meaning that most electricity is traded bilaterally or through decentralised power exchanges. However, ELEXON is responsible for metering and settling market participants in the Balancing Mechanism.
System operator	The transmission system throughout Great Britain is operated by National Grid, which is also responsible for balancing the system and ensuring that supply of electricity equals demand on a second-by-second basis.
Regulators	Ofgem regulates the electricity and gas markets and has responsibility for price controls and competition related matters.

PJM

Market overview	The PJM electricity market has annual energy consumption of around 682 TWh and total generation capacity of around 167,000 MW.
Policy	PJM Interconnection governs the PJM market.
Rule changes	PJM Interconnection manages the market manuals, which are the administrative, planning, operating and accounting procedures of the PJM.
Market operator	PJM Interconnection operates the wholesale electricity market.
System operator	PJM Interconnection is a Regional Transmission Organization that manages the transmission network to ensure reliability.
Regulators	State agencies are responsible for regulating retail supply, new generation consents and distribution networks. The Federal Energy Regulatory Commission (**FERC**) regulates, monitors and investigates wholesale energy markets and transmission. In particular, FERC is responsible for regulation of wholesale sales of electricity and transmission of electricity in interstate commerce; oversight of mandatory reliability standards for the bulk power system; promotion of strong national energy infrastructure, including adequate transmission facilities through rule changes; regulation of natural gas transportation in interstate commerce; establishment of rates for services for gas pipelines and approves open access transmission tariffs for the wholesale electricity market. FERC is also responsible for competition matters for the energy sector in PJM.

Appendix 7 Glossary of acronyms

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
ANAO	Australian National Audit Office
BSC	Balancing Support Contract
CCGT	Combined cycle gas turbine
CPRS	Carbon Pollution Reduction Scheme
CSO	Community Service Obligation
DDAP	Downward Deviation Administered Price
DMO	Dispatch Merit Order
DSM	Demand Side Management
EPL	Energy Price Limits
ERB	Electricity Review Board
FRC	Full retail contestability
IMO	Independent Market Operator
IPP	Independent Power Producer
LFAS	Load Following Ancillary Service
LGP	Landfill Gas and Power
LRET	Large-scale Renewable Energy Target
MAC	Market Advisory Committee
MCAP	Marginal Cost Administered Price
MEP	Market Evolution Program
MPI	Market participant interface
MRCP	Maximum Reserve Capacity Price
MSDC	Market Surveillance Data Catalogue
MW	Megawatt
MWh	Megawatt hour
NEM	National Energy Market
OCGT	Open cycle gas turbine
PASA	Projected Assessment of System Adequacy
RCM	Reserve Capacity Mechanism
RCMWG	Reserve Capacity Mechanism Working Group
RCP	Reserve Capacity Price
RCR	Reserve Capacity Requirement
RDIWG	Rules Development Implementation Working Group
RDQ	Relevant Demand Quantity
RET	Renewable Energy Target
RVC	Replacement Vesting Contract
SCADA	Supervisory control and data acquisition

SEA	Sustainable Energy Association
SRAS	Spinning Reserve Ancillary Service
SRES	Small-scale Renewable Energy Scheme
SRMC	Short run marginal cost
STEM	Short Term Energy Market
SWIS	South West interconnected system
TEC	Tariff equalisation contribution
UDAP	Upward Deviation Administered Price
VC	Vesting Contract
WEM	Wholesale Electricity Market

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Report for the Independent Market Operator

Performance requirements for demand-side and supply-side capacity resources May – Working Group Meeting DRAFT

Dr Richard Tooth

May 2012

sapere research group

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Contents

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

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1. Introduction

This is the second report for the Reserve Capacity Mechanism Working Group (RCMWG) on the issue of 'Performance requirements for demand-side and supply-side capacity resources'. It follows on from and complements the prior report provided at the April RCMWG meeting. Further background to the project from the prior report is contained in Box 1 below.

This paper puts forward some specific proposals for changing Demand Side Management (DSM) performance requirements. Proposals for changes to fuel supply requirements for Scheduled Generators will be put forward at the following RCMWG meeting.

In the prior report two high level options were put forward with regard to the treatment of DSM. These were:

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

The proposals put forward in this report build on these two broad options. They have been developed in conjunction with the Independent Market Operator (IMO) after considering a range of possible options. In developing the specific proposals there were a number of considerations.

- It is desirable to keep the proposals simple. The Wholesale Electricity Market (WEM) is a relatively small market and thus better suited to less complex approaches at this time. This is consistent with the recommendation of the RCMWG during its first meeting.
- The current issue of surplus capacity is the subject of a separate work-stream in the RCMWG, however it is expected that harmonising the peaking capacity requirements is likely to reduce the DSM resources that are available in the WEM.
- In the previous RCMWG meeting interest was expressed as to how DSM might be integrated into the new Balancing Market, scheduled to commence on 1 July 2012. This issue is discussed in this paper.

The rest of the report is structured as follows:

- The following section discusses relevant considerations for assessing performance requirements
- Section 2 puts forwards specific proposals regarding DSM
- Section 3 provides a preliminary discussion of DSM participation in the Balancing market.

Box 1: Background

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 addition in supply-side 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 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

Source: Report to April meeting or RCMWG.

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. Considerations

2.1 Objectives and the role of performance requirements

The core objective of this project is to ensure harmonisation of demand and supply side capacity resources. Harmonisation may be thought to involve harmonisation of the capacity value provided and harmonisation of operational requirements.

Ensuring harmonisation of capacity value is important to ensure an efficient level of investment in capacity resources. The capacity value is the marginal contribution a resource provides to reliability, which as noted in the previous report depends on nature of demand and other supply. The performance requirements associated with capacity resources have a key role in harmonising capacity value across different resources. By adjusting performance requirements, the capacity value of different resources can be aligned so that the marginal contribution is the same (or close to the same).

Harmonisation of capacity value does not necessarily mean absolute harmonisation in service levels. Different resources have different characteristics. It is not practical or desirable that service levels are identical. For example, it is unrealistic that:[2]

- all Scheduled Generation provide the same resilience to fuel supply shocks as DSPs
- all DSPs can operate for the same duration as many Scheduled Generators.

Harmonisation of operational requirements is also of interest to the extent that it affects an efficient use of the capacity resources. In this regard, performance requirements are relevant as they affect how resources are dispatched. The limitations on use provided by DSPs are a means of signalling when resources are more or less willing to be dispatched. For Scheduled Generators, the Balancing market is used as a means of determining the merit order of dispatch. In the previous RCMWG meeting the question was raised as to whether DSM might participate in the Balancing Market. This is considered in Section 4.

Of note, performance requirements can also affect the overall volume of capacity that is provided. For example, more stringent (or less stringent) performance requirements may alter the amount of capacity offered into the market. However, the objective of this project is to bring the treatment of different types of capacity resources closer together. As noted, using performance requirements to modify the total volume of capacity is not an objective within the scope of this project. A separate project is being undertaken to examine the overall level of capacity.

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2 Note: The Maximum Reserve Capacity Price is a related but separate process, for which an open-cycle gas generator is used to determine cost but not a service level.

2.2 Using performance requirements to harmonise capacity

2.2.1 Guidelines for performance requirements

A useful starting set of principles for Facilities receiving Capacity Credits is as follows:

- Facilities that obtain Capacity Credits must be available when required
- Facilities don't need to be available at times if there is no risk to reliability.

In effect these principles are currently applied in awarding Capacity Credits to different resource types. For example, under this principle:

- The performance of Intermittent Generators during non-peak periods is not used to determine their Capacity Credits
- DSPs are not required to be available after 8pm
- Scheduled Generators can apply for Planned Outages which must be granted within reason.

In theory it would be possible to develop performance requirements that accommodate each individual Facility's preferences for availability that do not compromise reliability. However, this would be unworkable in practice and is inconsistent with the RCMWG's recommendation to explore simple options first.

In practice, some pragmatic application is appropriate. Performance requirements can be thought of as simple rules that help to ensure that Facilities that earn Capacity Credits are available when required.

It is useful to consider why any limitations on availability are necessary. If Facilities are dispatched in an efficient order then a Facility need only be dispatched when it is required.

Rather than allow limitations on availability an alternative approach which could be applied to harmonise the treatment of DSM with other forms of capacity is as follows:

- There are no limitations placed on availability
- Resources are not penalised for non-performance if dispatched when unnecessary.

Such an approach puts the onus on resources to ensure they are available when required. A Facility can choose to be unavailable (i.e. not to be dispatched) so long as there are other resources that are available to be dispatched to meet the required load. Similarly Facility owners would need to consider the risk of being required on any particular Trading Interval.

Such an approach is, in appearance, a simple means of harmonising the requirements of all scheduled resources. However, there are a number of challenges. First, given the low likelihood of all available Facilities being required, the penalties for non-performance would need to be appropriate to ensure Facilities have sufficient incentive to be available when required. Second is the problem of how to manage dispatch. Whereas the Balancing Market provides a means of organising efficient dispatch during normal events, during a high risk operating state System Management needs information on availability to effectively manage system reliability. Allowing limitation on scheduled resource availability (notification of planned outages and limitations of DSP use) is a means of addressing these issues. The limitations provide information that System Management can use in managing an efficient dispatch and approval of these limitations conveys information to Facilities as to when they will be required.

Given these considerations, the role of performance requirements is to set minimum standards of availability that do not compromise reliability but are helpful in the efficient management of resources. It is on this principle that the performance requirements are considered.

2.2.2 Need for capacity

In setting performance requirement parameters it is useful to consider when capacity resources will be required. The need for capacity ultimately depends on demand and the availability of other resources.

The reliability criteria provides for a generous level of capacity. The current capacity requirement is set to a 1 in 10 year peak forecast plus a buffer (of greater than 10% of forecast peak demand). Given this minimum level of capacity, reliability is only at risk when there is a combination of a high level of demand and a large amount of plant outage. Given that planned outages, by construction, occur at times of low reliability risk, for the purposes of examining reliability risk it is appropriate to focus on Forced Outages (and the less frequent Consequential Outages).

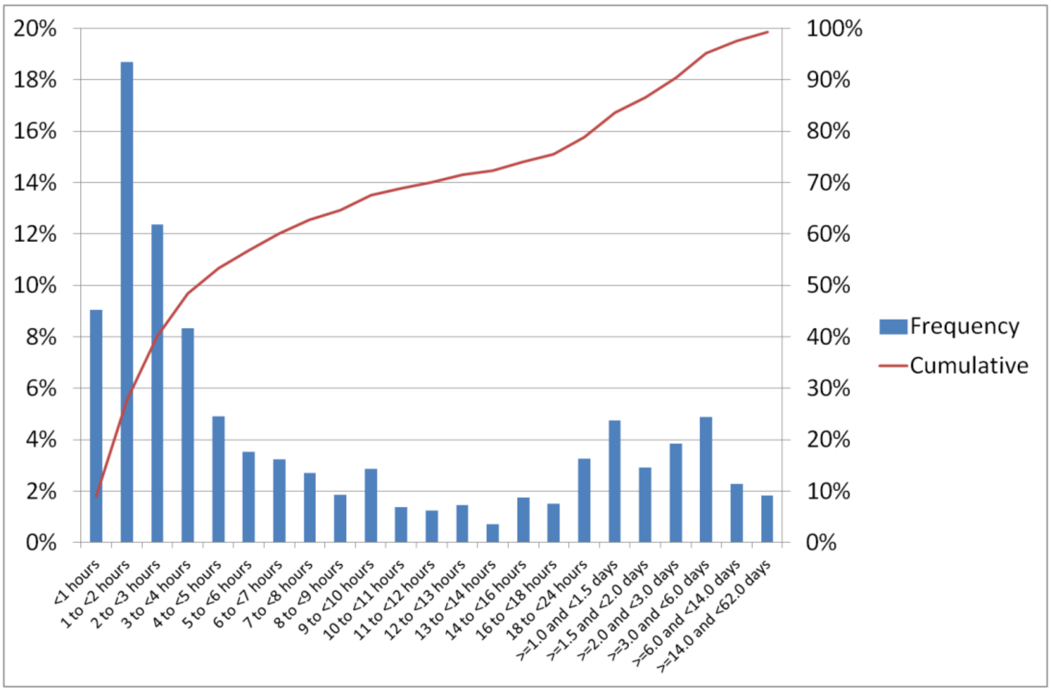
While demand is uncertain, it largely follows predictable patterns with peak demand occurring generally occurring in the afternoon on a hot summer weekday.

For the purposes of this report some examination of Forced Outages was undertaken. There are also some patterns to Forced Outages. Forced Outages are more frequent at particular times. Consistent with outages occurring when plant is being started Forced Outages are more likely to occur:

- In the months December to February
- On weekdays (and in particular Mondays)
- At the beginning of the day.

The length of Forced Outages is also an important consideration. While the length varies significantly, most Forced Outages are short – around 50 percent of outage volume lasts for less than 4 hours

Figure 1: Length of forced outages (weighted by output)



Source: Forced outages since market start.

2.2.3 Reliability risks and performance criteria

Given the pattern of demand and outages there are a number of risk scenarios for which performance requirements may be relevant. Potential scenarios that have been identified are described in the following table.

Table 1: Reliability risk scenarios of relevance to performance requirements

Scenario	How limitations on availability of capacity resources might be binding
S1 Frequent high demand plus frequent outages over a long summer	Risk that more calls of DSM required than available
S2 One-off high number of outages during high demand day	Risk that there is insufficient capacity with short notice period and/or continuous duration capacity required is insufficient
S3 Continual high demand plus outages over consecutive days	Risk that DSM unavailable 3rd consecutive day. Risk if fuel cannot be replenished on daily basis for Scheduled Generators.
S4a Minor fuel supply (or transmission) disruption	As per scenario 3 but higher risk that fuel can't be replenished.
S4b Major fuel supply disruption	Availability limitations may be largely irrelevant

3. Availability of DSM

3.1 Overview

As noted in the prior report, DSPs can nominate a number of limitations on their use subject to some minimum requirements. The key minimum requirements and the proportion of capacity nominating at the minimum requirement is described in Table 2 below. As shown in the table below, in most cases the minimum requirement is nominated.

Table 2: Nominated DSP availability

Performance requirement parameter	Minimum requirement	Percent of capacity at the minimum for Capacity Year 2013/14
Dispatch events per year	At least 6	79%
Hours per day	4 hours per day	81%
Total hours	24 hours	79%
Earliest start	12 noon	71%
Latest finish	8pm	67%
Minimum notice period of dispatch	Must be less or equal to 4 hours	Information to be obtained

Source: DSP nominations

As noted in the previous paper, the extent to which a limitation detracts from the capacity value of DSM depends on the penetration of DSM. The greater the penetration of the limited-availability DSM, the greater the risk that the limitations are binding.

The penetration of DSM has been increasing and based on assigned Capacity Credits will reach 8.2% (500 MW) in 2013/14. The Availability Curve for 2013/2014 (Statement of Opportunities 2011) allows for much greater penetration. It allows for 909 MW (availability class 4) from a total capacity requirement of 5,312 MW — a potential penetration of 17 percent.[3] However, there are natural limits to DSM penetration. As noted in EnerNOC's submission, the current level of DSM penetration in the WEM is similar to the more mature North American markets.

[3] Of note the 909 MW does not set a cap of the amount of DSM that can be provided but is used to determine the amount of the capacity requirement that must be met by Scheduled Generation.

The level of penetration will depend on a number of factors. Stricter performance requirements will likely result in a reduced volume of DSM being offered to the market. Furthermore the volume of DSM offered will vary with other market factors (including the value of Capacity Credits and the level of capacity).

A quantity cap could be applied to address the problem of too high a penetration of limited availability DSM.[4] However such an approach is not simple. If a cap is applied some means of selection would be necessary when more resources are provided than the cap allows. In the North American PJM market a cap is applied and a market process is used to allocate different demand programs into different product types and to form a separate capacity price for different products. Simpler approaches (e.g. a random or first come first served selection) might be possible but would not be as equitable.

In the interests of simplicity and equity a preferred approach is to modify the performance requirement parameters to ensure that they are appropriate given the likely level of DSM penetration.

The key parameters are investigated below. As noted in the previous section a key principle is that requirements set minimum standards of availability that do not compromise reliability but are helpful in the efficient management of resources. It is recognised that a tightening of any parameter may change the capacity value of DSM and make the resource more comparable with other resources but may also result in some loss of DSM. In developing options for changes, options have been considered that either improve reliability or increase the benefits without a loss of reliability. Changes that impose requirements on DSM for no improvement in reliability are not proposed.

The discussion in the previous section also highlighted the relationship between performance requirements and dispatch. The availability limitations should not prevent an individual Facility being available if required; however, it can be desirable to allow a Facility to be dispatched outside of its nominated availability limitations. Such additional resource availability can help to reduce the overall cost of reliability. This approach is analogous to Scheduled Generators being able to produce more energy than they have been certified for capacity.

It is however appropriate that procedures ensure that, consistent with the short and long-term Market Objectives, DSPs are not dispatched unnecessarily. This approach is consistent with the dispatch of scheduled generators, which are only dispatched when they are both required (i.e. to meet a load requirement) and (notwithstanding nergy price limits) at a price which covers the costs of generation.

4 Note that the 909 WM penetration limit is much higher than the current DSP penetration and would unlikely be inappropriate as a cap.

Proposal 1

DSP Facilities may be dispatched outside of nominated availability limitations on a best efforts basis (i.e. with no implications for capacity payment refunds for non-performance).

3.2 Hours availability

The number of hours required of DSM is the product of the number of dispatch events required and the duration of each event. Thus to determine total hours required it is necessary first to consider how often DSM is required (the number of dispatch events) and for how long.

3.2.1 Number of dispatch events

The number of dispatch events required is determined by the number of days on which DSM might be required. A useful approach to estimating the number of days required is to consider for any given capacity year if all DSM were required on the highest peak Trading Interval on how many days would at least some DSM be required.

The answer to this question depends on assumptions about the penetration of DSM and profile of load and outages over a capacity year. A starting point is to consider historical data on loads and outages as this data may provide a guide to how peak demands vary in the course of a capacity year. To simplify the analysis a single measure of the load to be met by available scheduled generation is calculated from the sum of demand (being load and curtailed load) and Forced Outages less Intermittent Generation.[5]

Figure 2 below compares the peak-in-the-day load for the highest peak days relative to the yearly peak for five Capacity Years. In effect it shows historical 'load' duration curves based on the peak trading intervals in each day with the peak normalised to 0 MW. The results are ordered by critical peak (CP) load days. Thus an amount of -400MW on CP6 indicates that on the 6th highest peak day the capacity required from available resources was 400MW less than that required on the peak day.

The figure can be used to ask the question 'if all DSM had been required on the highest peak Trading Interval then on how many different days would some DSM have been required?' The figure indicates that if all DSM had been required at once on the most peak day in these capacity years, on the 6th most peak day (CP6) about 400 MW less of DSM would have been required in the years 2006/07 through to 2008/09 but only about 100MW less would have been required in the capacity year 2010/11. Thus if the 2010/11 year was a guide then, the analysis would suggest that many more dispatch events would be required than the current minimum of 6 events. Based on the 2010/11 profile and a DSM penetration of over 400 MW, some DSM would be dispatched on more than 15 days.

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5 For the purposes of determining the need for a DSP or other any other schedule resources, a Forced Outage is of similar effect as an increase in demand. Similarly Intermittent Generation is has a similar effect to a reduction in demand.

There are, however, a number of qualifications and considerations. The variation in required capacity increases with load and analysis based on low demand years is not necessarily representative. The peak requirements on the years analysed was still significantly less than available capacity. This was particularly the case in 2010/11. If the difference to the peak was measured in percentage terms the amount of dispatch days in 2010/11 would fall to 11 days assuming a DSP penetration of 8 percent.

The number of dispatch events required of a DSP may also be less if not all DSPs are dispatched at once. The analysis is based on all DSPs being required on the peak day, however only a smaller amount being required on other days.

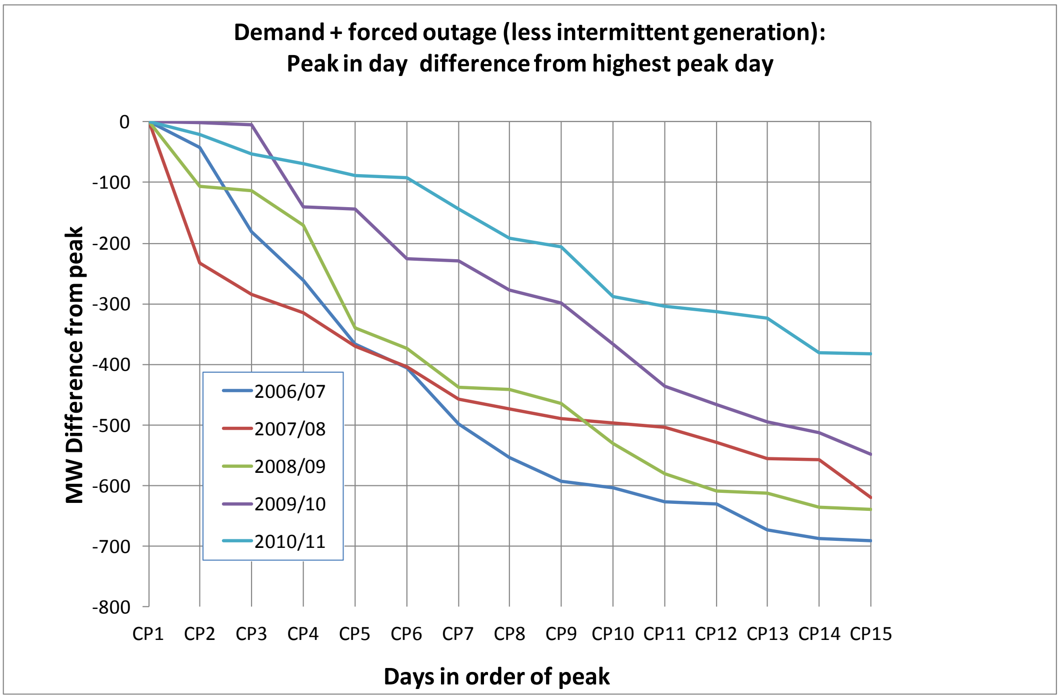
The scenarios under which DSM is required are also a consideration. In the event of an extended fuel disruption over a hot summer DSM may be required for a large number of days (which in turn highlights the contribution of DSM during a fuel disruption). Another scenario for which DSM is used is that there are a number of coincidental outages for other reasons. While outages may reoccur, the likelihood of coincidental outages running for a large number of days appears remote.

From System Management's perspective a limitation on the number of dispatch events may make System Management more reluctant to dispatch DSPs when there is some uncertainty if it will be required.[6]

From a DSP's perspective the minimum number of dispatch events may be of little concern. Notwithstanding the previous point, if the likelihood of being required on more than 15 days is remote then there is negligible additional burden of being required for more than 15 days. This is the case so long as the increased availability of dispatch does not affect the perceived frequency at which DSM is dispatched.

6 If there was no uncertainty in requirements then there should be no uncertainty as to whether DSM should either be used or not used.

Figure 2: Capacity requirements by day as percent of peak day



Source: Outages and market data

On the balance of these scenarios it is recommended that the minimum number of dispatch events be increased to a minimum of 15 events.

It is also recommend that the alternative of an unlimited number of dispatch events be considered. As noted above, such a policy would impose a negligible additional impost on DSPs so long as such a policy did not alter the perceived likelihood of being dispatched. Such a policy might be supported by additional guidelines to ensure that DSPs are not dispatched unnecessarily (or are not penalised when they are). Unlimited dispatch would be administratively simpler and be more consistent with a goal of harmonisation.

Proposal 2

The minimum number of dispatch events is increased to 15 events; or

Alternatively, the number of dispatch events becomes unlimited, and guidelines put in place to help ensure that DSPs are not dispatched unnecessarily (or are not penalised when they are).

3.2.2 The hours per day

Currently DSPs are required to be available for a minimum of 4 hours per day.

International practice is often longer. For example, for the most basic product in PJM, the minimum is 6 hours — for other products a longer duration is required. In some cases there is no limit, however such a policy is generally coupled with some protections. For example, in ISO NY, performance is measured over the best 4 continuous hours.

There are two scenarios where the hours per day limitation might result in DSPs being unavailable when required. First, there is a risk that the peak requirements during the course of day last longer than can be met with by DSPs with a 4 hour limit.

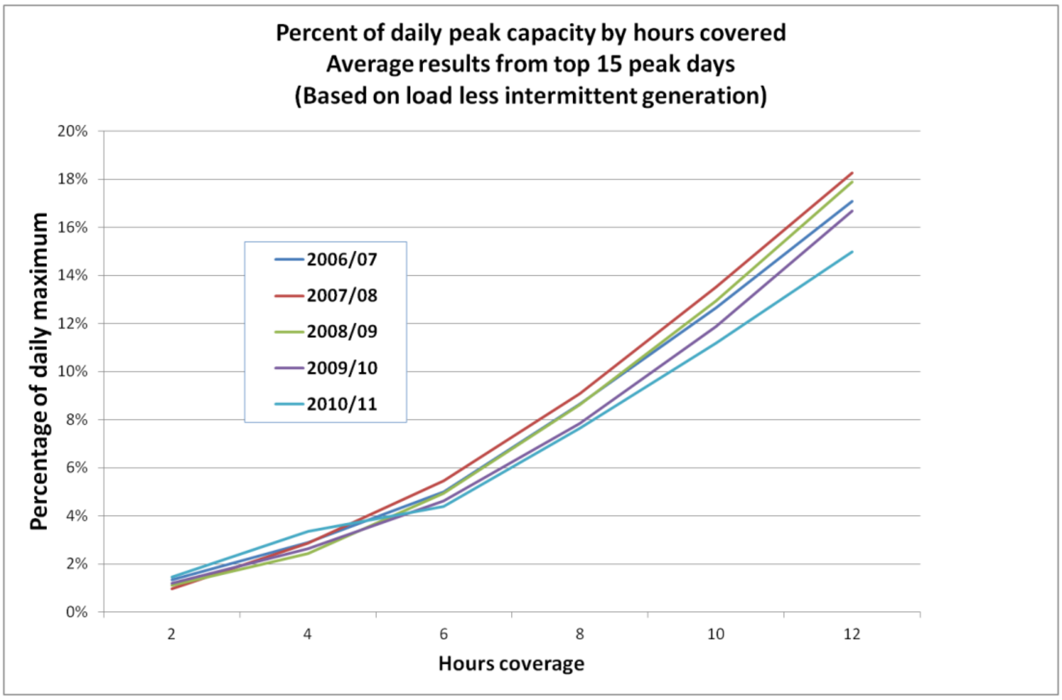
This scenario can be analysed by considering how much DSM is required to meet the peak. An illustration of the issue was presented in the previous report. Subsequently some analysis has been undertaken to determine what duration for DSM would be required given historical peak day profiles. A guide can be assessed by considering the number of hours of duration to cover a given reduction in peak of the day. Analysis based on the years 2006/07 through to 2010/11 is provided in Figure 3 below. The figure illustrates that if the top 8 percent of peak load was removed, the average width (in terms of hours) of the remaining peak would be around 7 to 8 hours.

There are some important qualifications, which suggest that DSPs would not necessarily be required for as long. In particular:

- DSP use can be staggered (as was the case when it was used in 2010/11). For example, by staggering the use of DSPs, DSPs with 4 hours duration could be used to cover a period of up to 7 hours (depending on shape of load curve) while still having all DSPs being used at the absolute peak.
- DSPs ramp up and ramp down i.e. there are benefits to DSPs outside of when they are called.
- The reliability risk depends on there being outages. Given the short-term nature of most outages the duration required of DSPs is likely to be less.
- Finally, some DSPs (around 20 percent in 2013/14) nominate for longer periods or could be voluntarily dispatched for longer periods. Thus it is not necessary that all DSPs provide such a long period.

The required duration depends very much on the penetration of DSM. An increase in the minimum duration requirement would induce a reduction in the amount of DSM provided. Given consideration of the above factors and current levels of penetration, a minimum duration of 6 hours may be sufficient.

Figure 3: Hours coverage required to meet peak loads



Source/ notes: Based on peak-load.

A second scenario for when the dispatch duration of DSP may be important is in its use in helping to manage a fuel crisis that occurs over a number of days. Using DSPs allows fuel stocks to be stretched further. The longer each DSP is available the more useful it will be in such a scenario.

There are a number of factors in considering the extent to which this scenario should be considered. The benefit of using DSM to manage the reliability risk associated with fuel supply shocks depends on the total amount of DSM as well as its duration. An increase in the number of required hours may reduce the amount of DSM available for such a scenario. To the extent that DSM is required to be available for such a scenario reflects the important contribution that DSM can provide.

A change in the minimum hours per day may have significant implications for amount of DSM offered. There are some limitations for DSPs in providing a longer period. Some loads may have operational limits that prevent them running for longer periods. For example:

- A backup generator may only have a limited supply of fuel
- There are limits to how long a refrigeration unit may be switched off.

While aggregators may still use the loads, the total amount of DSM load that can be used at the same time would be reduced. Of note, DSP aggregators can aggregate a number of loads with differing operational restrictions into a capacity program so as to meet the minimum operational standards. The total gross capacity level of a DSP (the total capacity level if all the capacity was used at the same time) may be in excess of the capacity credits allocated to the program.

Proposal 3

The minimum duration (and hours per day) for DSPs be increased to at least 6 hours and possibly 8 hours.

3.2.3 Total number of hours

Given a minimum number of dispatch events of around 15 events and minimum number of hours per day of 6 to 8 hours, a total number of available hours would need to be at least 90-120 hours per Capacity Year.

This could most easily be achieved by retiring the low-availability DSM classes (thereby forming a single DSM Availability Class) and specifying a minimum requirement of (say) 100 hours.

Consistent with the option of an unlimited number of dispatches, it is recommended an unlimited-hours option also be considered. This would be consistent with availability requirements of Scheduled Generators.

Proposal 4

A single availability class be used for which DSP is available for 100 hours, or

Alternatively, there is a single availability class with an unlimited number of hours

(DSPs would not be penalised if they were dispatched outside of their required period of availability).

3.3 Period of availability

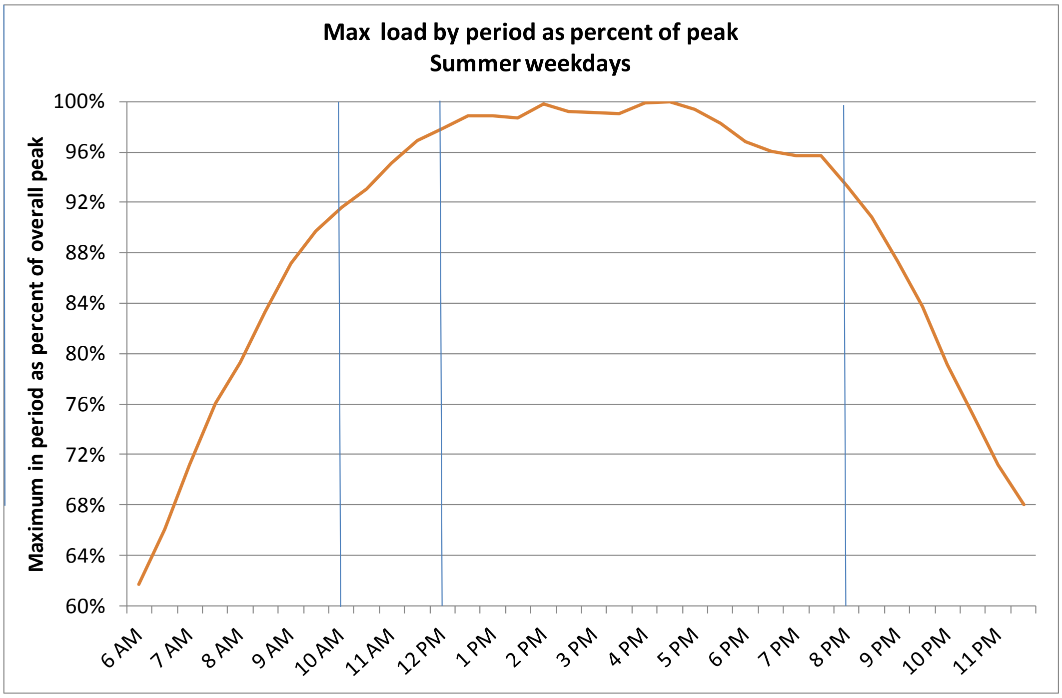
Currently DSPs must make themselves available from between the hours of 12 noon to 8 pm on business days.

The minimum start of noon does not appear to be sufficient. Figure 4 below shows the profile of maximum requirement for scheduled capacity[7] over the course of the day as percentage of the recorded peak.[8] As highlighted in the figure, the peak requirement at 12 noon is greater than that at 8 pm and within 4 percent of the peak requirement. Based on this analysis a required start of at least 10 am appears more appropriate. This is also appropriate given that an outage is more likely to be identified early in the morning.

[7] The requirement for scheduled capacity is measured as measured load + curtailed load less intermittent generation.

[8] For clarity of illustration the figure shows a summary based on all summer peak periods measured over the entire period 2005/06 to 2010/11. A similar pattern occurs for any individual year.

Figure 4: Peak load by period as percent of peak



Source: Summer weekdays 2005/06 to 2010/11.

Similar analysis was also undertaken on whether DSPs should be made available on weekends. Based on historical profiles weekend demand is sufficiently low that it is unnecessary to require DSPs to be available to maintain reliability over weekends. As DSM requires a reduction in demand, many loads associated with DSPs are less likely to be available over weekends. One possible use for DSPs over a weekend is during a fuel crisis to help reduce fuel stocks to support reliability of Scheduled Generators during the following week – for this reason it is preferable that DSPs be used on an optional basis.

Proposal 5

The minimum requirement for DSPs is brought forward so that DSPs must be available from 10am.

There is no change to the requirement that DSPs are not required to be available on weekends.

3.4 Notice period

Currently there is a maximum 4 hour notice period for DSM, that is, DSPs can nominate up-to 4 hours notification before being dispatched. There is no allowance for ramping-up.

In typical circumstances the dispatch order of facilities is determined some time in advance. Under the Balancing market, the merit order is largely established the day before. The gate closure period for the new balancing market will be initially 6 hours but will fall to 2 hours.

However, a 4 hour notice period may be problematic for two reasons.

First, a potential reliability risk is that there are a number of sudden outages. Many Forced Outages are only realised at the time of dispatch. Should a sudden outage occur, System Management can call on the capacity that forms part of the Ready Reserve Standard (capacity that is available to be dispatched within 15 minutes). To keep to the Ready Reserve Standard requirement, System Management may then need to dispatch DSPs to free up some capacity. During the notice period, reliability could be compromised should another Forced Outage occur.

Second, a shorter notice period is desirable to prevent unnecessary dispatch of DSPs. For example, System Management may dispatch DSPs with 4 hours notice to hedge against an uncertain need. The need for capacity may be uncertain 4 hours in advance as a result of uncertain demand and uncertain supply from Intermittent Generation (and to extent from other generation due to outages). A shorter notice period would enable System Management to gain further information before choosing to dispatch. To the extent that System Management can respond to changing conditions in such a way, DSPs have an incentive to nominate a shorter dispatch notice period as it may mean that they can avoid being dispatched.

A shorter notice period could be easily accommodated by some DSPs but may prove problematic for others. In other systems the policy on notification varies. Other policies include:

- A 2 hour notification period with allowance for time ramp-up (as is the case in the PJM market).
- A 2 hour notification period but with a day-ahead notification of probable use (as is the case in the NYISO market).

Providing some advance warning (i.e. day-ahead notification) of probable dispatch would appear reasonable — in effect the Balancing Market provides this for Scheduled Generation.

Given the above considerations it is recommended a 2 hour minimum notification is appropriate coupled with best endeavours day-ahead notification of probable use.

Proposal 6

The minimum notification period be set at 2-hour period but is coupled with a day-ahead notification of probable use.

3.5 Third-day rule

As noted in the prior report, currently, a DSP (under clause 4.12.8) that has been dispatched for a 3rd continuous day is not subject to capacity refund payments.

There is some risk that this limitation is important. It is extremely unlikely that *all* DSPs would be required for three continuous days as this would necessitate an equivalently high level of demand and outage over three continuous days. However some continuous of DSPs over three consecutive days is a possibility. For example:

- Following a fuel disruption, some DSPs are required for three continuous days to help manage a risk to fuel stocks.
- A very hot series of days coupled with some coincident large outages.

In the interests of maintaining a generic rule for all DSPs, it is recommended that:

- the third-day rule is removed, and
- when DSPs are dispatched, the dispatch order for DSPs is organised such that DSPs that have been dispatched on previous days are dispatched last where possible.

Proposal 7

The third day rule is removed. The default dispatch order for DSPs is set to ensure that DSPs dispatched on previous days are dispatched last.

3.6 Real time information on DSP performance

A challenge with the use of DSPs, is that System Management does not have real-time information on the availability and performance of DSPs. The lack of information means that System Management is likely to be less confident in the use of DSM and less able to efficiently use DSPs. For example, without real time information System Management would be more likely to dispatch all DSPs at once rather than stagger the use of DSPs.

Real-time information (telemetry) is possible and is a requirement by ISO-NE for participation in 'Real Time Emergency Generation Resource' demand response product.[9] However, telemetry is not a mandatory requirement for participation in other markets.[10] There is a cost to telemetry — both to DSPs in providing it and System Management in being able to make use of the information. Rather than make it mandatory, DSPs could be encouraged to provide telemetry services if procedures allowed for DSPs providing telemetry services to be dispatched later. Nevertheless in the interest of harmonisation and consistency across resources there is benefit to a consistent provision of real-time information on availability and performance.

9 Of note it is appropriate that the information provided to System Management is on the availability and performance of the DSPs and not the underlying loads.

10 It is not a requirement for participation in emergency demand response programs in other ISO/RTO is North America.

Proposal 8

A requirement for future DSPs is that telemetry service be provided to enable real time information on availability and performance be recorded.

It is recommended that the requirement for existing DSPs would be aligned to the transition arrangements policy.

4. Participation in the balancing market

An issue raised in the previous working group meeting was how to incorporate DSPs into the Balancing Market.

The Balancing Market relates to the capacity market[11] in that it serves to ensure an efficient order of dispatch and through this an efficient use of resources to manage reliability.[12] However, the potential to do so for DSPs is currently limited. Under the new Balancing market DSPs will be placed in a separate dispatch order and will not actively participate in the Balancing Market.

There are a number of challenges associated with using the Balancing Market for organising the dispatch of DSPs. These include the following:

- The net cost to the market of dispatching DSPs is higher than that of Scheduled Generators for the same dispatch payment because dispatching a DSP does not produce energy, and therefore the dispatch payment is funded by other Market Customers. As such an inefficient outcome is likely to occur if a DSP is dispatched ahead of a Scheduled Generator.
- The energy price limits are based on the cost of thermal generation and do not necessarily reflect the efficient dispatch price of DSPs, which may be much higher. With rare exception, DSPs all bid at the maximum price cap. Thus the price limits prevent an efficient ordering of DSP dispatch.
- There is a challenge in integrating an availability hours performance requirement (i.e. whereby a DSP may be available for a total amount of hours). When DSPs only need to be available for a set number of hours they may have incentive to be dispatched out of an efficient merit order to use up the hours.
- Other challenges associated with how DSPs perform and how their performance is measured. DSPs can only reduce demand against an existing level of demand i.e. they cannot reduce demand at some times. Furthermore measurement is currently relative to a static Relevant Demand level.

Potentially each of these issues might be addressed. However, there is also the question of the significance of the benefits. Of note, DSPs and other rarely used Scheduled Generator Facilities:

11 DSPs can also play a useful role in the energy market primarily to overcome a problem of non-cost reflective user-pricing. Curtailable loads also have value in providing ancillary services — for example, demand response programs are used to provide load following services in PJM.

12 To meet the requirements of the absolute peak all available resources may be required and thus the order of dispatch may appear to be unimportant. However, the order of dispatch is important for managing a number of scenarios.

- will generally be dispatched during high risk operating states. At these times System Management may organise the dispatch in the order that it views necessary for ensuring power system security.
- will not have experience in using the Balancing Market to organise dispatch.

Nevertheless the potential for using the Balancing Market to efficiently organise DSP resources is worth further investigation in future Market Evolution planning.

RCM Progress Update

Mike Thomas

29 May 2012

THE LANTAU GROUP
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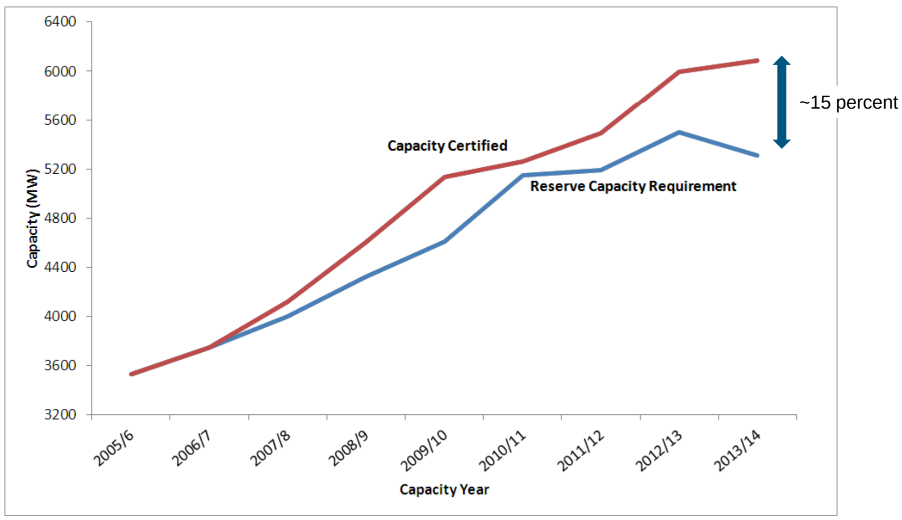
Agenda

- Situation
  - Excess reserve capacity has increased
  - Demand uncertainty
  - The MRCP has decreased substantially
  - Investment appears to have curtailed
- Problem
  - Economic value of capacity is highly sensitive to market conditions
  - The RCP formulation does not respond to these factors nearly enough (up or down)
- Proposal

The growing issue of excess reserve capacity



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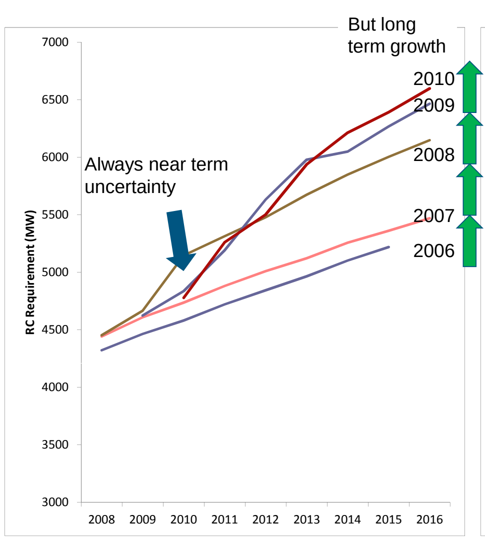
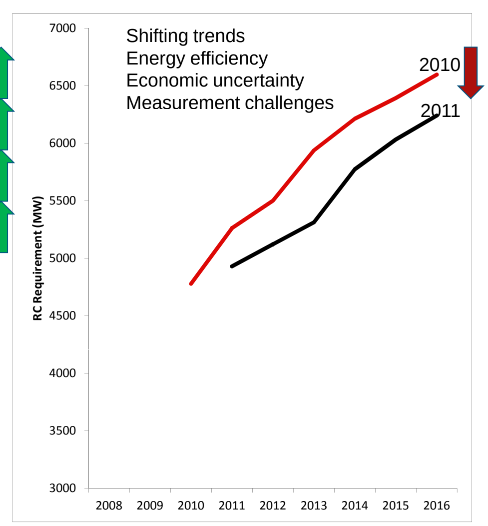
Demand uncertainty





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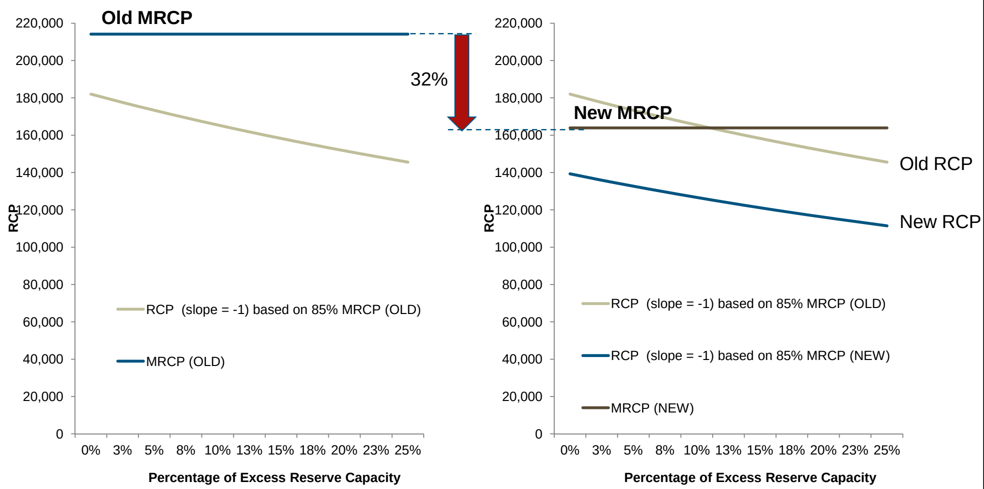
Recent MRCP revision significantly reduces the RCP

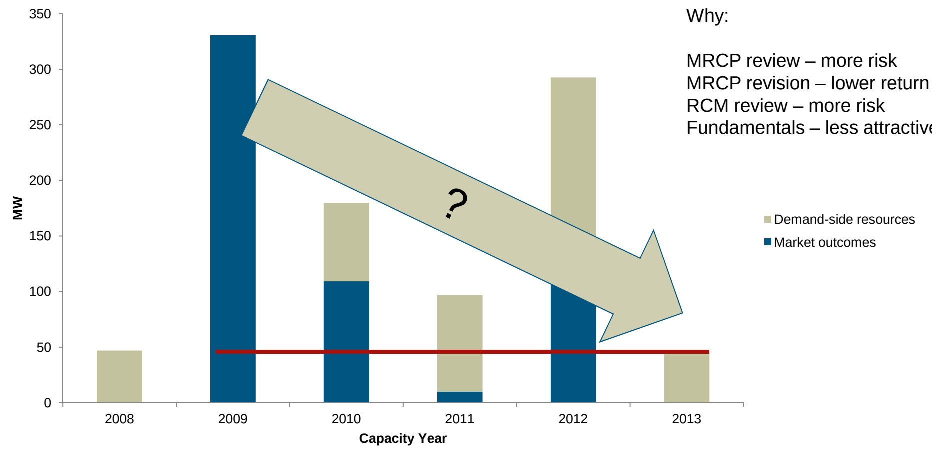


Why is the MRCP called the MRCP?

- M = Maximum
- But the process for calculating the “MRCP” defines an expected value
  - Rigorously determined estimates
  - Actual costs
- Maximum range values are not used to calculate the MRCP
- No probability of exceedence factor or explicit allowance for contingency is incorporated
- No allowance for any other commercial risk beyond the WACC
- Other markets do not define a “maximum” based on an expected value.

Proposal: Rename the MRCP to reflect that it is a best estimate (“Benchmark RCP”)

Apparent reduction in capacity investment



Why:

MRCP review – more risk
MRCP revision – lower return
RCM review – more risk
Fundamentals – less attractive

Investment has slowed – various reasons. While this is "good" , the RCM remains relatively unresponsive to market conditions

Concern: Some excess reserve capacity costs flow through to end-users

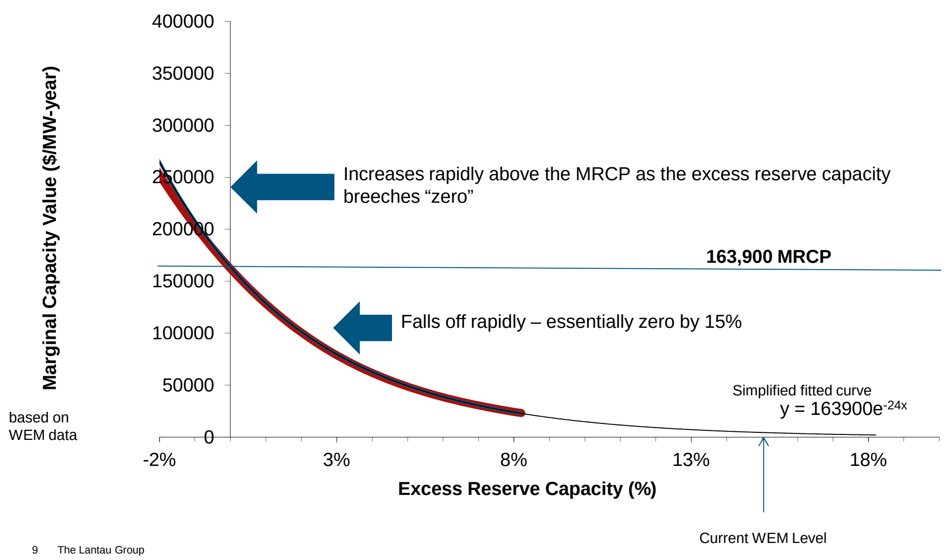
- If retailers are bilaterally contracted, they bear a portion of the cost of excess reserve capacity
  - The RCP adjustment only flows through capacity credits that are purchased through the IMO
  - Not consistent with a market design intended to feature bilateral contracting
- If there is any incentive to support excess reserve capacity then at least some end-users bear additional costs
  - They do obtain somewhat more "security"
  - But the costs are borne disproportionately by bilaterally contracted load-serving entities
  - And the cost of additional capacity credits is above their market value

Anything that reduces the incentive and cost of excess reserve capacity reduces this risk

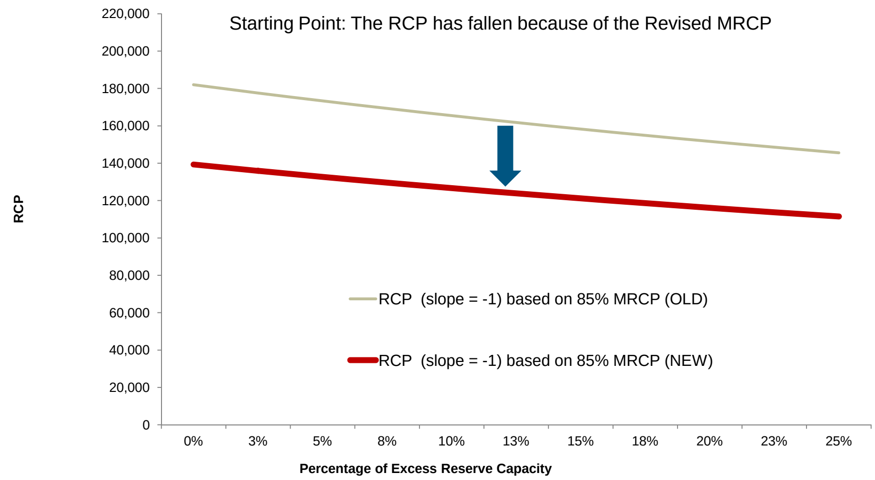
Summary of situation

- Excess reserve capacity has persisted, stubbornly, and increased.
- Impact on retailers and end-users is not benign
- MRCP review introduced significant changes
- RCP does not respond sufficiently (up or down) when market conditions change
- Uncontracted capacity receives a valuable "option" benefit to utilise IMO capacity credits when retailers or end-users place no value on them, but the cost of this option is charged to contracted retailers and end-users

Observation: the economic value of capacity declines at an exponential rate as the amount of excess reserve capacity increases



The RCP falls at a much more shallow rate – the bigger reduction is due to the MRCP revision



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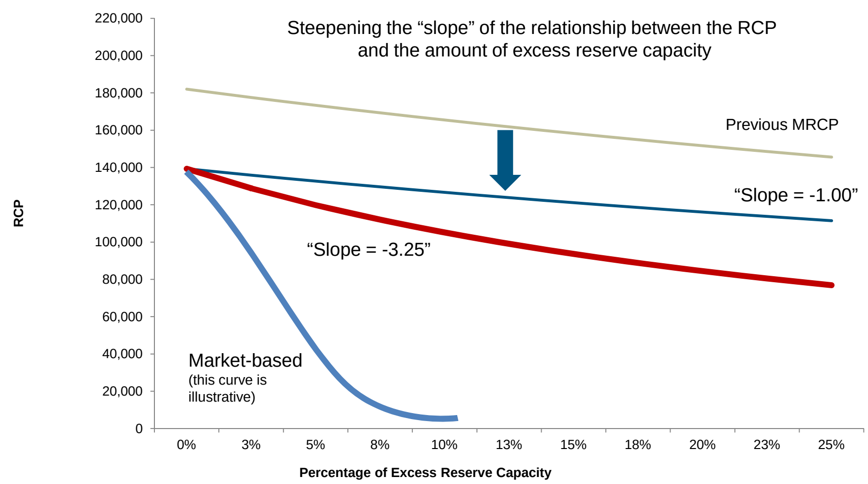
Steeper slope makes the RCP more responsive



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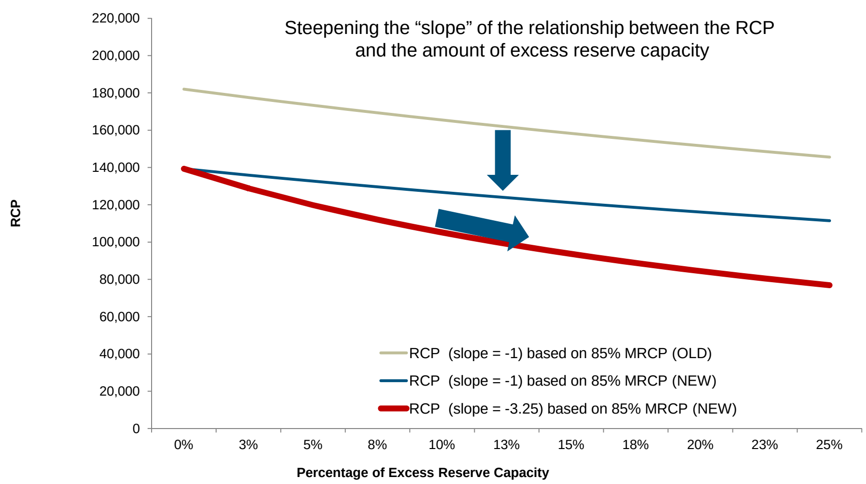
But how steep? Some design principles

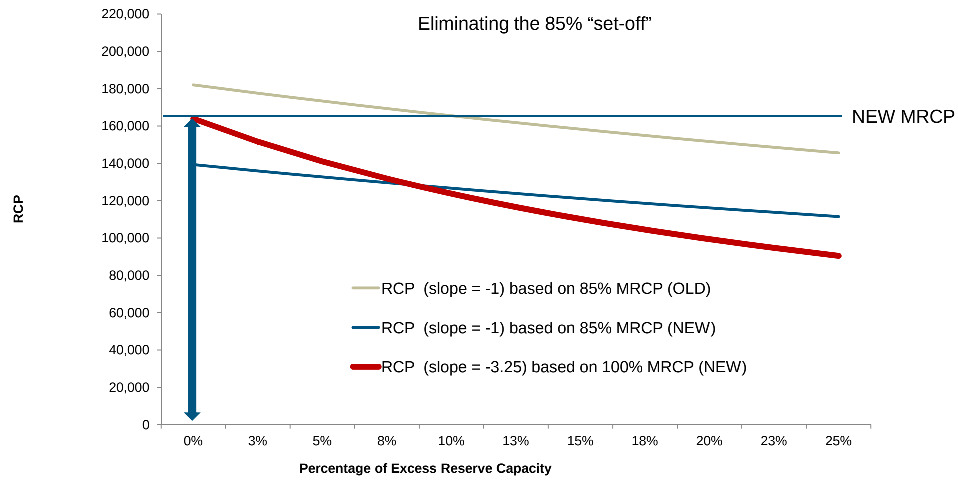
- Steepness should not be greater than what a market would produce
- Mechanism should support needed investment without supporting excess
- Should support commercial risk management (contracting and trading) where possible, without imposing offsetting volatility or risk
- Should not reward inefficient behaviours or rent-seeking gaming
- Should not hamper (should be consistent with) a longer-term evolution towards greater reliance on market mechanisms

Should promote or be consistent with the Market Objectives

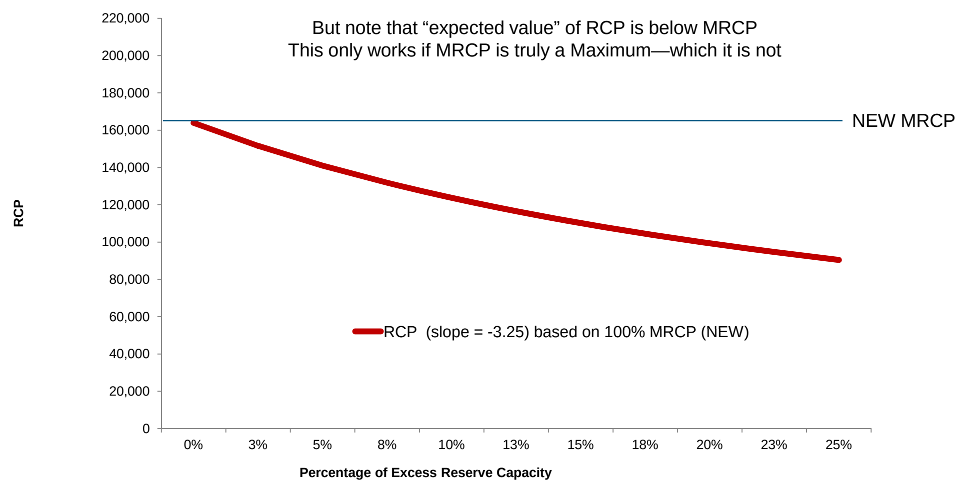
Walking through changes to the RCM (1 of 3)



Walking through the proposed changes to the RCM (2 of 3)



Interaction between RCP and "MRCP"



Selecting the ceiling above "benchmark" RCP

Amount of Excess Reserve Capacity	RCP (slope = -3.25) based on 110% NEW MRCP
0.0%	180,290
2.5%	166,742
5.0%	155,088
7.5%	144,957
10.0%	136,068
12.5%	128,206
15.0%	121,203

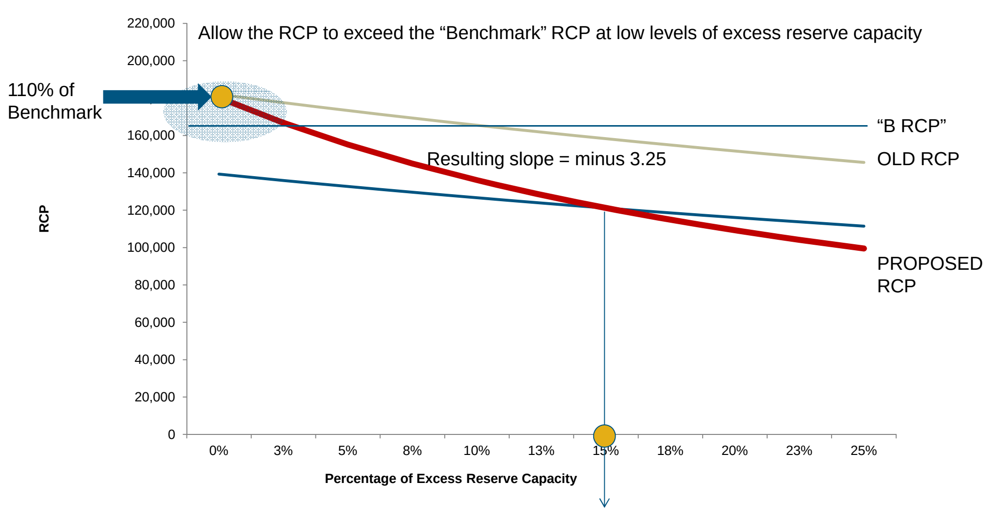
	Expected Value
0-10.0% (average of 5 values)	156,629
0-7.5% (average of 4 values)	161,769
0-5.0% (average of 3 values)	167,373

Benchmark

163,900

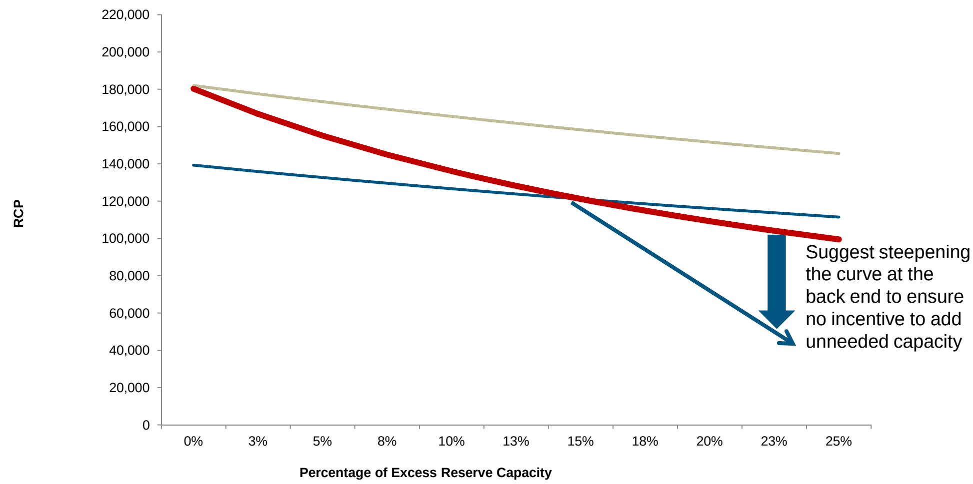
110% appears reasonable if long-term excess reserve capacity is within 0 to 5 or 7 percent
(Not advised to increase above this, as supplementary auction provides secure backstop)

Setting the slope and reference point to benchmark results in minimal change in RCP compared to current settings – no transition required

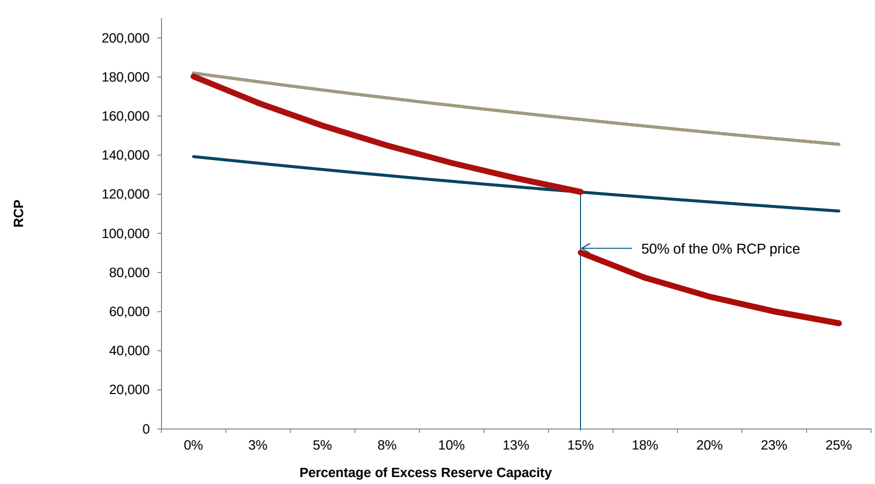


Approximate current level of excess reserve capacity

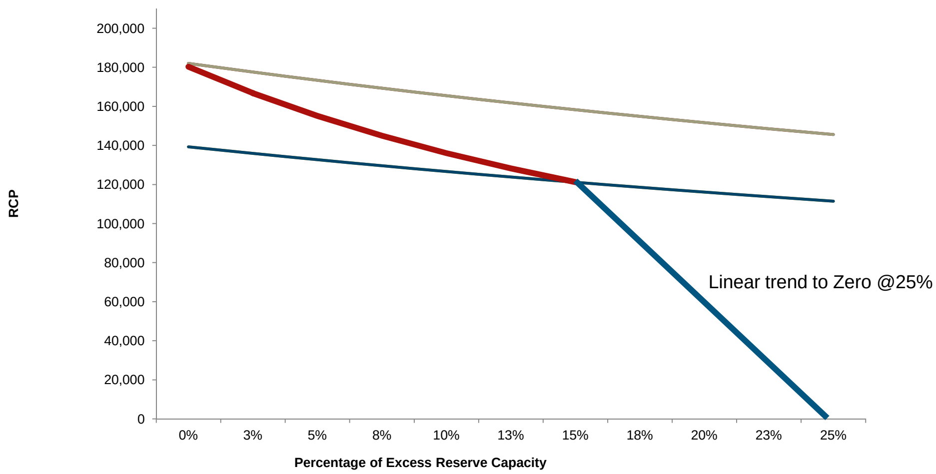
While steeper than present arrangements, the proposed "slope" does not necessarily mitigate the cost of severe excess reserve capacity



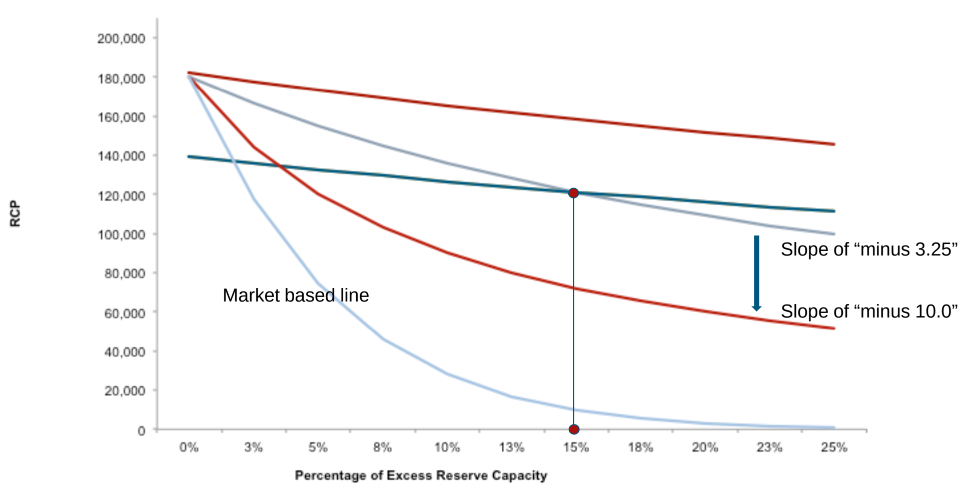
Option 1: Introduce a step change at 15%



Option 2: Trend to RCP=Zero at 25%



Option 3: Use even steeper slope, but transition



Summary

- The RCP is not dynamic enough to accommodate the significant changes in market conditions that we see in the WEM
- The RCP can easily be made more dynamic
  - Steepen the “slope” factor
  - Up to 3.25 slope without any transition issues
  - Some additional adjustment after 15% excess reserve capacity is reasonable
- At same time
  - Change name of “MRCP” to reflect what it actually is and avoid confusion
  - Eliminate 85% MRCP offset as it has no basis in logic given the way the MRCP is now calculated
- The above would link the RCP more strongly to market conditions, while retaining a managed character
  - More robust during “up” and “down” economic cycles

The proposed changes are consistent with a longer-term evolution direction

- Key elements of a workable auction model for valuing capacity credits
  - Develop a profiled future obligation for load serving entities (LSEs) – similar to the IRCR
    - 1 year-out: 100% of IRCR
    - 2 years-out: 95 to 100 % of IRCR
    - 3 years-out: 80% to 90% of IRCR
    - 4 years-out: 50% to 80% of IRCR etc.
  - Develop an acceptable verification process and potential backstop to assure capacity forward contracts are credible
    - Can be achieved by a material financial commitment
    - Standard may need to become more physical / supported by testing/verification as date approaches
  - Define auction “product” and differentiate role of auction from role of trading
    - multi-year contracts or single year credits?
    - if single-year credits: for what (future) year
    - determine if credits need to have vintages or other attributes
- Auction processes involve considerable complexity – as indicated by the frequent revisions to capacity auction designs found in other major capacity markets

Devil is in the details: PJM's Reliability Pricing Model (RPM)

- Implemented in 2007, the RPM, based on making capacity commitments three years ahead, is designed to create long-term price signals to attract needed investments in reliability in the PJM region.
  - The long-term RPM approach…includes incentives that are designed to stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity – resources that include not just generating plants, but demand response and transmission facilities.
  - The RPM model works in conjunction with PJM's Regional Transmission Expansion Planning (RTEP) process to ensure the reliability of the PJM region for future years.
  - The RPM includes the continued use of self-supply and bilateral contracts by load-serving entities (LSEs) to meet their capacity obligations.
  - The capacity auctions under the RPM obtain the remaining capacity that is needed after market participants have committed the resources they will supply themselves or provide through contracts.
- The RPM provides:
  - Procurement of capacity three years before it is needed through a competitive auction;
  - Locational pricing for capacity that reflects limitations on the transmission system's ability to deliver electricity into an area and to account for the differing need for capacity in various areas of PJM;
  - A variable resource requirement to help set the price for capacity;
  - A backstop mechanism to ensure that sufficient resources will be available to preserve system reliability.

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Observation: the longer-term value of capacity credits is more stable than the shorter-term value

- The existing "RCM" is not a spot market for capacity credits – it is merely a support mechanism for a reasonable and secure capacity supply
  - The longer-term value is based on the estimated LRMC, not current supply & demand conditions
- The RCM needs to respond to short-term conditions, but should also be consistent with longer-term investment signals

Year new capacity is needed	Present Value of a future Capacity Credit
Year 0	163,900
Year +1	153,421
Year +2	143,613
Year +3	134,431
Year +4	125,836
Year +5	117,791
Year +6	110,260
Year +7	103,211
Year +8	96,612
Year +9	90,436
Year +10	84,654

Based on WACC = 6.83

Agenda Item 7: Dynamic Reserve Capacity Refund regime – Consideration to date

1. BACKGROUND

The Reserve Capacity Mechanism Working Group (RCMWG) Terms of Reference includes the consideration of a Dynamic Reserve Capacity Refund regime. This paper provides a background of the development of the regime to date and is intended to guide further discussions by the RCMWG with respect to the next steps in the process.

2. OVERVIEW OF CONSIDERATIONS TO DATE

The Dynamic Reserve Capacity Refund regime was considered by the Rules Development Implementation Working Group (RDIWG) at several meetings prior to the decision to include the regime into the review of the Reserve Capacity Mechanism. A brief overview of the key milestones in the development of the regime is presented below:

- At the 15 March 2011 meeting (Meeting 10) Mr Greg Thorpe (Oakley Greenwood) presented a paper on the Review of Capacity Cost Refunds which included for discussion the creation of a dynamically calculated refund regime and the level of refunds. At this meeting, RDIWG members agreed that a dynamic refund regime should be established.

- At the 5 April 2011 meeting (Meeting 11), the IMO presented a paper outlining the following alternative refund mechanisms:

  - A dynamic refund rate based on the reserve available in any particular interval.

  - A refund rate based on a dynamic reserve calculation overlaid with longer term factors.

  The IMO proposed the adoption of a basic reserve related refund approach. A copy of the paper containing the IMO's proposal is provided as Appendix 1 to this paper.

  During the same meeting Griffin Energy presented an alternative refund regime design that would differentiate facilities by type and therefore recognise that the incentives for availability of facilities differ.

- At the 31 May 2011 meeting (Meeting 13), the IMO provided a paper outlining the core principles behind the Reserve Capacity Refunds design. During the same meeting Mr Mike Thomas (The Lantau Group) provided the RDIWG with details of The Lantau Groups peer review of the changes proposed to the refund regime and then assess the their impact and consistency with the broader Reserve Capacity Mechanism review. A copy of The Lantau Groups paper is provided as Appendix 2 to this paper. A brief overview of the recommendations presented by The Lantau Group is provided below:

  - Consideration of the refund regime is recommended only in the context of the broader review of the RCM, as implementing the proposed dynamic refund regime without making nay other changes to the RCM itself would have the effect of reducing refund exposure to generators;

- A more integrated solution would be to link changes to the refund regime to changes to the RCM itself. For example, a consistent change would see the introduction of a more market-based price paid by the IMO for Capacity Credits.

- Potential to include a symmetric aspect to the refunds regime such that penalties for failure to present capacity can be offset to a degree by the ability to present more capacity than has been accredited.

- Cautioned against early adoption of the dynamic refund regime and recommended the IMO explicitly consider the interactions between the refund regime and the Reserve Capacity Mechanism and coordinated the proposed changes.

The RDIWG accepted the of IMO/ The Lantau Group that any changes to the refund regime should be considered as part of the Reserve Capacity Review (albeit requesting that the removal of the net STEM Shortfall refund obligation proceed with the other proposed changes for the new Balancing market).

A copy of the papers presented to the RDIWG at the meetings is available on the following Market Web Site: http://www.imowa.com.au/RDIWG

3. RECOMMENDATIONS

The IMO recommends that the RCMWG:

- note the key milestones in the development of a dynamic refund regime to date; and

- discuss the proposed basic reserve related refund approach (Appendix 1).

- discuss the recommendations presented in The Lantau Report (Appendix 2).